Supreme Court of the United States
FEDERAL POWER COMMISSION et al.
v.
HOPE NATURAL GAS CO.
CITY OF CLEVELAND
v.
SAME.
Nos. 34 and 35.

Argued Oct. 20, 21, 1943.
Decided Jan. 3, 1944.

Separate proceedings before the Federal Power Commission by such Commission, by the City of Cleveland and the City of Akron, and by Pennsylvania Public Utility Commission wherein the State of West Virginia and its Public Service Commission were permitted to intervene concerning rates charged by Hope Natural Gas Company which were consolidated for hearing. An order fixing rates was reversed and remanded with directions by the Circuit Court of Appeals, 134 F.2d 287, and Federal Power Commission, City of Akron and Pennsylvania Public Utility Commission in one case and the City of Cleveland in another bring certiorari.

Reversed.

Mr. Justice REED, Mr. Justice FRANKFURTER and Mr. Justice JACKSON, dissenting.

On Writs of Certiorari to the United States Circuit Court of Appeals for the Fourth Circuit.

West Headnotes

[1] **Public Utilities 317A 120**

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak120 k. Nature and Extent in General. Most Cited Cases
(Formerly 317Ak7.1, 317Ak7)
Rate-making is only one species of price-fixing which, like other applications of the police power, may reduce the value of the property regulated, but that does not render the regulation invalid.

[2] **Public Utilities 317A 123**

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak123 k. Reasonableness of Charges in General. Most Cited Cases
(Formerly 317Ak7.4, 317Ak7)
Rates cannot be made to depend upon fair value, which is the end product of the process of rate-making and not the starting point, when the value of the going enterprise depends on earnings under whatever rates may be anticipated.

[3] **Gas 190 14.3(2)**

190 Gas
190k14 Charges
190k14.3 Administrative Regulation
190k14.3(2) k. Federal Power Commission. Most Cited Cases
(Formerly 190k14(1))
The rate-making function of the Federal Power Commission under the Natural Gas Act involves the making of pragmatic adjustments, and the Commission is not bound to the use of any single formula or combination of formulae in determining rates. Natural Gas Act, § § 4(a), 5(a), 6, 15 U.S.C.A. § § 717c(a), 717d(a), 717e.

[4] **Gas 190 14.5(6)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(6) k. Scope of Review and Trial De Novo. Most Cited Cases
(Formerly 190k14(1))
When order of Federal Power Commission fixing natural gas rates is challenged in the courts, the question is whether order viewed in its entirety meets the requirements of the Natural Gas Act. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[5] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges

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190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
Under the statutory standard that natural gas rates shall be "just and reasonable" it is the result reached and not the method employed that is controlling. Natural Gas Act § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[6] **Gas 190 14.5(6)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(6) k. Scope of Review and Trial De Novo. Most Cited Cases
(Formerly 190k14(1))
If the total effect of natural gas rates fixed by Federal Power Commission cannot be said to be unjust and unreasonable, judicial inquiry under the Natural Gas Act is at an end. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[7] **Gas 190 14.5(7)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(7) k. Presumptions. Most Cited Cases
(Formerly 190k14(1))
An order of the Federal Power Commission fixing rates for natural gas is the product of expert judgment, which carries a presumption of validity, and one who would upset the rate must make a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[8] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
The fixing of just and reasonable rates for natural gas by the Federal Power Commission involves a balancing of the investor and the consumer interests. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[9] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
As respects rates for natural gas, from the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business, which includes service on the debt and dividends on stock, and by such standard the return to the equity owner should be commensurate with the terms on investments in other enterprises having corresponding risks, and such returns should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[10] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
The fixing by the Federal Power Commission of a rate of return that permitted a natural gas company to earn $2,191,314 annually was supported by substantial evidence. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[11] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
Rates which enable a natural gas company to operate successfully, to maintain its financial integrity, to attract capital and to compensate its investors for the risks assumed cannot be condemned as invalid, even though they might produce only a meager return on the so-called "fair value" rate base. Natural Gas Act,

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§ § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[12] **Gas 190 14.4(4)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(4) k. Method of Valuation. Most Cited Cases
(Formerly 190k14(1))
A return of only 3 27/100 per cent. on alleged rate base computed on reproduction cost new to natural gas company earning an annual average return of about 9 per cent. on average investment and satisfied with existing gas rates suggests an inflation of the base on which the rate had been computed, and justified Federal Power Commission in rejecting reproduction cost as the measure of the rate base. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[13] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
There is no constitutional requirement that owner who engages in a wasting-asset business of limited life shall receive at the end more than he has put into it, and such rule is applicable to a natural gas company since the ultimate exhaustion of its supply of gas is inevitable. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[14] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
In fixing natural gas rate the basing of annual depreciation on cost is proper since by such procedure the utility is made whole and the integrity of its investment is maintained, and no more is required. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[15] **Gas 190 14.3(4)**

190 Gas
190k14 Charges
190k14.3 Administrative Regulation
190k14.3(4) k. Findings and Orders. Most Cited Cases
(Formerly 190k14(1))
There are no constitutional requirements more exacting than the standards of the Natural Gas Act which are that gas rates shall be just and reasonable, and a rate order which conforms with the act is valid. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[16] **Commerce 83 62.2**

83 Commerce
83II Application to Particular Subjects and Methods of Regulation
83II(B) Conduct of Business in General
83k62.2 k. Gas. Most Cited Cases
(Formerly 83k13)
The purpose of the Natural Gas Act was to provide through the exercise of the national power over interstate commerce an agency for regulating the wholesale distribution to public service companies of natural gas moving in interstate commerce not subject to certain types of state regulation, and the act was not intended to take any authority from state commissions or to usurp state regulatory authority. Natural Gas Act, § 1 et seq., 15 U.S.C.A. § 717 et seq.

[17] **Mines and Minerals 260 92.5(3)**

260 Mines and Minerals
260III Operation of Mines, Quarries, and Wells
260III(A) Statutory and Official Regulations
260k92.5 Federal Law and Regulations
260k92.5(3) k. Oil and Gas. Most Cited Cases
(Formerly 260k92.7, 260k92)
Under the Natural Gas Act, the Federal Power Commission has no authority over the production or gathering of natural gas. Natural Gas Act, § 1(b), 15 U.S.C.A. § 717(b).

[18] **Gas 190 14.1(1)**

190 Gas
190k14 Charges
190k14.1 In General
190k14.1(1) k. In General; Amount and

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Regulation. Most Cited Cases
(Formerly 190k14(1))
The primary aim of the Natural Gas Act was to protect consumers against exploitation at the hands of natural gas companies and holding companies owning a majority of the pipe-line mileage which moved gas in interstate commerce and against which state commissions, independent producers and communities were growing quite helpless. Natural Gas Act, § § 4, 6-10, 14, 15 U.S.C.A. § § 717c, 717e-717i, 717m.

[19] **Gas 190 14.1(1)**

190 Gas
190k14 Charges
190k14.1 In General
190k14.1(1) k. In General; Amount and Regulation. Most Cited Cases
(Formerly 190k14(1))
Apart from the express exemptions contained in § 7 of the Natural Gas Act considerations of conservation are material where abandonment or extensions of facilities or service by natural gas companies are involved, but exploitation of consumers by private operators through maintenance of high rates cannot be continued because of the indirect benefits derived therefrom by a state containing natural gas deposits. Natural Gas Act, § § 4, 5, and § 7 as amended 15 U.S.C.A. § § 717c, 717d, 717f.

[20] **Commerce 83 62.2**

83 Commerce
83II Application to Particular Subjects and Methods of Regulation
83II(B) Conduct of Business in General
83k62.2 k. Gas. Most Cited Cases
(Formerly 83k13)
A limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state, either to safeguard its tax revenues from such industry, or to protect the interests of those who sell their gas to the interstate operator, particularly where the return allowed the company by the Federal Power Commission was a net return after all such charges. Natural Gas Act, § § 4, 5, and § 7, as amended, 15 U.S.C.A. § § 717c, 717d, 717f.

[21] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
The Natural Gas Act granting Federal Power Commission power to fix "just and reasonable rates" does not include the power to fix rates which will disallow or discourage resales for industrial use. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[22] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
The wasting-asset nature of the natural gas industry does not require the maintenance of the level of rates so that natural gas companies can make a greater profit on each unit of gas sold. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[23] **Federal Courts 170B 452**

170B Federal Courts
170BVII Supreme Court
170BVII(B) Review of Decisions of Courts of Appeals
170Bk452 k. Certiorari in General. Most Cited Cases
(Formerly 106k383(1))
Where the Federal Power Commission made no findings as to any discrimination or unreasonable differences in rates, and its failure was not challenged in the petition to review, and had not been raised or argued by any party, the problem of discrimination was not open to review by the Supreme Court on certiorari. Natural Gas Act, § 4(b), 15 U.S.C.A. § 717c(b).

[24] **Constitutional Law 92 74**

92 Constitutional Law
92III Distribution of Governmental Powers and Functions
92III(B) Judicial Powers and Functions
92k71 Encroachment on Executive
92k74 k. Powers, Duties, and Acts Under Legislative Authority. Most Cited Cases
(Formerly 15Ak226)
Congress has entrusted the administration of the

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Natural Gas Act to the Federal Power Commission and not to the courts, and apart from the requirements of judicial review, it is not for the Supreme Court to advise the Commission how to discharge its functions. Natural Gas Act, § § 1 et seq., 19(b), 15 U.S.C.A. § § 717 et seq., 717r(b).

[25] **Gas 190 14.5(3)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(3) k. Decisions Reviewable. Most Cited Cases
(Formerly 190k14(1))
Under the Natural Gas Act, where order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action, the order is not reviewable, and resort to the courts in such situation is either premature or wholly beyond the province of such courts. Natural Gas Act, § 19(b), 15 U.S.C.A. § 717r(b).

[26] **Gas 190 14.5(4)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(4) k. Persons Entitled to Relief; Parties. Most Cited Cases
(Formerly 190k14(1))
Findings of the Federal Power Commission on lawfulness of past natural gas rates, which the Commission was without power to enforce, were not reviewable under the Natural Gas Act giving any "party aggrieved" by an order of the Commission the right of review. Natural Gas Act, § 19(b), 15 U.S.C.A. § 717r(b).

****283 *592** Mr. Francis M. Shea, Asst. Atty. Gen., for petitioners Federal Power Com'n and others.
***593** Mr. Spencer W. Reeder, of Cleveland, Ohio, for petitioner City of cleveland.
Mr. William B. Cockley, of Cleveland, Ohio, for respondent.
Mr. M. M. Neeley, of Charleston, W. Va., for State of West Virginia, as amicus curiae by special leave of Court.

Mr. Justice DOUGLAS delivered the opinion of the Court.
The primary issue in these cases concerns the validity under the Natural Gas Act of 1938, 52 Stat. 821, 15 U.S.C. s 717 et seq., 15 U.S.C.A. s 717 et seq., of a rate order issued by the Federal Power Commission reducing the rates chargeable by Hope Natural Gas Co., 44 P.U.R.,N.S., 1. On a petition for review of the order made pursuant to s 19(b) of the Act, the ***594** Circuit Court of Appeals set it aside, one judge dissenting. 4 Cir., 134 F.2d 287. The cases ****284** are here on petitions for writs of certiorari which we granted because of the public importance of the questions presented. City of Cleveland v. Hope Natural Gas Co., 319 U.S. 735, 63 S.Ct. 1165.

Hope is a West Virginia corporation organized in 1898. It is a wholly owned subsidiary of Standard Oil Co. (N.J.). Since the date of its organization, it has been in the business of producing, purchasing and marketing natural gas in that state. [FN1] It sells some of that gas to local consumers in West Virginia. But the great bulk of it goes to five customer companies which receive it at the West Virginia line and distribute it in Ohio and in Pennsylvania. [FN2] In July, 1938, the cities of Cleveland and Akron filed complaints with the Commission charging that the rates collected by Hope from East Ohio Gas Co. (an affiliate of Hope which distributes gas in Ohio) were excessive and unreasonable. Later in 1938 the Commission on its own motion instituted an investigation to determine the reasonableness of all of Hope's interstate rates. In March ***595** 1939 the Public Utility Commission of Pennsylvania filed a complaint with the Commission charging that the rates collected by Hope from Peoples Natural Gas Co. (an affiliate of Hope distributing gas in Pennsylvania) and two non-affiliated companies were unreasonable. The City of Cleveland asked that the challenged rates be declared unlawful and that just and reasonable rates be determined from June 30, 1939 to the date of the Commission's order. The latter finding was requested in aid of state regulation and to afford the Public Utilities Commission of Ohio a proper basic for disposition of a fund collected by East Ohio under bond from Ohio consumers since June 30, 1939. The cases were consolidated and hearings were held.

FN1 Hope produces about one-third of its annual gas requirements and purchases the rest under some 300 contracts.

FN2 These five companies are the East Ohio Gas Co., the Peoples Natural Gas Co., the

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River Gas Co., the Fayette County Gas Co., and the Manufacturers Light & Heat Co. The first three of these companies are, like Hope, subsidiaries of Standard Oil Co. (N.J.). East Ohio and River distribute gas in Ohio, the other three in Pennsylvania. Hope's approximate sales in m.c.f. for 1940 may be classified as follows:

Local West Virginia. sales.	11,000,000
East Ohio.	40,000,000
Peoples.	10,000,000
River.	400,000
Fayette.	860,000
Manufacturers.	2,000,000

Local West Virginia

Hope's natural gas is processed by Hope Construction & Refining Co., an affiliate, for the extraction of gasoline and butane. Domestic Coke Corp., another affiliate, sells coke-oven gas to Hope for boiler fuel.

On May 26, 1942, the Commission entered its order and made its findings. Its order required Hope to decrease its future interstate rates so as to reflect a reduction, on an annual basis of not less than $3,609,857 in operating revenues. And it established 'just and reasonable' average rates per m.c.f. for each of the five customer companies. [FN3] In response to the prayer of the City of Cleveland the Commission also made findings as to the lawfulness of past rates, although concededly it had no authority under the Act to fix past rates or to award reparations. 44 P.U.R.,U.S., at page 34. It found that the rates collected by Hope from East Ohio were unjust, unreasonable, excessive and therefore unlawful, by $830,892 during 1939, $3,219,551 during 1940, and $2,815,789 on an annual basis since 1940. It further found that just, reasonable, and lawful rates for gas sold by Hope to East Ohio for resale for ultimate public consumption were those required ***596** to produce $11,528,608 for 1939, $11,507,185 for 1940 and $11.910,947 annually since 1940.

FN3 These required minimum reductions of 7¢ per m.c.f. from the 36.5¢ and 35.5¢ rates previously charged East Ohio and Peoples, respectively, and 3¢ per m.c.f. from the 31.5¢ rate previously charged Fayette and Manufacturers.

The Commission established an interstate rate base of $33,712,526 which, it found, represented the 'actual legitimate cost' of the company's interstate property less depletion and depreciation and plus unoperated acreage, working capital and future net capital additions. The Commission, beginning with book cost, made ****285** certain adjustments not necessary to relate here and found the 'actual legitimate cost' of the plant in interstate service to be $51,957,416, as of December 31, 1940. It deducted accrued depletion and depreciation, which it found to be $22,328,016 on an 'economic-service-life' basis. And it added $1,392,021 for future net capital additions, $566,105 for useful unoperated acreage, and $2,125,000 for working capital. It used 1940 as a test year to estimate future revenues and expenses. It allowed over $16,000,000 as annual operating expenses-about $1,300,000 for taxes, $1,460,000 for depletion and depreciation, $600,000 for exploration and development costs, $8,500,000 for gas purchased. The Commission allowed a net increase of $421,160 over 1940 operating expenses, which amount was to take care of future increase in wages, in West Virginia property taxes, and in exploration and development costs. The total amount of deductions allowed from interstate revenues was $13,495,584.

Hope introduced evidence from which it estimated reproduction cost of the property at $97,000,000. It also presented a so-called trended 'original cost' estimate which exceeded $105,000,000. The latter was designed 'to indicate what the original cost of the property would have been if 1938 material and labor prices had prevailed throughout the whole period of the piece-meal construction of the company's property since 1898.' 44 P.U.R.,N.S., at pages 8, 9. Hope estimated by the 'percent condition' method accrued depreciation at about 35% of ***597** reproduction cost new. On that basis Hope contended for a rate base of $66,000,000. The Commission refused to place any reliance on reproduction cost new, saying that it was 'not predicated upon facts' and was 'too conjectural and illusory to be given any weight in these proceedings.' Id., 44 P.U.R.,U.S., at page 8. It likewise refused to give any 'probative value' to trended 'original cost' since it was 'not founded in fact' but was 'basically erroneous' and produced 'irrational results.' Id., 44 P.U.R., N.S., at page 9. In determining the amount of accrued depletion and depreciation the Commission, following Lindheimer v. Illinois Bell

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Telephone Co., 292 U.S. 151, 167-169, 54 S.Ct. 658, 664-666, 78 L.Ed. 1182; Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 592, 593, 62 S.Ct. 736, 745, 746, 86 L.Ed. 1037, based its computation on 'actual legitimate cost'. It found that Hope during the years when its business was not under regulation did not observe 'sound depreciation and depletion practices' but 'actually accumulated an excessive reserve' [FN4] of about $46,000,000. Id., 44 P.U.R.,N.S., at page 18. One member of the Commission thought that the entire amount of the reserve should be deducted from 'actual legitimate cost' in determining the rate base. [FN5] The majority of the ***598** Commission concluded, however, that where, as here, a business is brought under regulation for the first time and where incorrect depreciation and depletion practices have prevailed, the deduction of the reserve requirement (actual existing depreciation and depletion) rather than the excessive reserve should be made so as to ****286** lay 'a sound basis for future regulation and control of rates.' Id., 44 P.U.R.,N.S., at page 18. As we have pointed out, it determined accrued depletion and depreciation to be $22,328,016; and it allowed approximately $1,460,000 as the annual operating expense for depletion and depreciation. [FN6]

FN4 The book reserve for interstate plant amounted at the end of 1938 to about $18,000,000 more than the amount determined by the Commission as the proper reserve requirement. The Commission also noted that 'twice in the past the company has transferred amounts aggregating $7,500,000 from the depreciation and depletion reserve to surplus. When these latter adjustments are taken into account, the excess becomes $25,500,000, which has been exacted from the ratepayers over and above the amount required to cover the consumption of property in the service rendered and thus to keep the investment unimpaired.' 44 P.U.R.,N.S., at page 22.

FN5 That contention was based on the fact that 'every single dollar in the depreciation and depletion reserves' was taken 'from gross operating revenues whose only source was the amounts charged customers in the past for natural gas. It is, therefore, a fact that the depreciation and depletion reserves have been contributed by the customers and do not represent any investment by Hope.' Id., 44 P.U.R.,N.S., at page 40. And see Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 424, 425, 29 S.Ct. 357, 361, 362, 53 L.Ed. 577; 2 Bonbright, Valuation of Property (1937), p. 1139.

FN6 The Commission noted that the case was 'free from the usual complexities involved in the estimate of gas reserves because the geologists for the company and the Commission presented estimates of the remaining recoverable gas reserves which were about one per cent apart.' 44 P.U.R.,N.S., at pages 19, 20.

The Commission utilized the 'straight-line-basis' for determining the depreciation and depletion reserve requirements. It used estimates of the average service lives of the property by classes based in part on an inspection of the physical condition of the property. And studies were made of Hope's retirement experience and maintenance policies over the years. The average service lives of the various classes of property were converted into depreciation rates and then applied to the cost of the property to ascertain the portion of the cost which had expired in rendering the service.

The record in the present case shows that Hope is on the lookout for new sources of supply of natural gas and is contemplating an extension of its pipe line into Louisiana for that purpose. The Commission recognized in fixing the rates of depreciation that much material may be used again when various present sources of gas supply are exhausted, thus giving that property more than scrap value at the end of its present use.

Hope's estimate of original cost was about $69,735,000-approximately $17,000,000 more than the amount found by the Commission. The item of $17,000,000 was made up largely of expenditures which prior to December 31, 1938, were charged to operating expenses. Chief among those expenditures was some $12,600,000 expended ***599** in well-drilling prior to 1923. Most of that sum was expended by Hope for labor, use of drilling-rigs, hauling, and similar costs of well-drilling. Prior to 1923 Hope followed the general practice of the natural gas industry and charged the cost of drilling wells to operating expenses. Hope continued that practice until the Public Service Commission of West Virginia in 1923 required it to capitalize such expenditures, as does the Commission under its present Uniform System of Accounts. [FN7] The Commission refused to add such items to the rate base stating that 'No greater injustice to consumers could be done than to allow items as operating expenses and at a later date include them in the rate base, thereby placing multiple charges upon the consumers.' Id., 44 P.U.R.,N.S., at page 12. For the same reason the Commission excluded from the rate base about $1,600,000 of expenditures on properties which Hope acquired from other utilities, the latter having charged those payments to operating expenses. The Commission disallowed certain other overhead items amounting to

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over $3,000,000 which also had been previously charged to operating expenses. And it refused to add some $632,000 as interest during construction since no interest was in fact paid.

FN7 See Uniform System of Accounts prescribed for Natural Gas Companies effective January 1, 1940, Account No. 332.1.

Hope contended that it should be allowed a return of not less than 8%. The Commission found that an 8% return would be unreasonable but that 6 1/2% was a fair rate of return. That rate of return, applied to the rate base of $33,712,526, would produce $2,191,314 annually, as compared with the present income of not less than $5,801,171.

The Circuit Court of Appeals set aside the order of the Commission for the following reasons. (1) It held that the rate base should reflect the 'present fair value' of the ***600** property, that the Commission in determining the 'value' should have considered reproduction cost and trended original cost, and that 'actual legitimate cost' (prudent investment) was not the proper measure of 'fair value' where price levels had changed since the investment. (2) It concluded that the well-drilling costs and overhead items in the amount of some $17,000,000 should have been included in the rate base. (3) It held that accrued depletion and depreciation and the annual allowance for that expense should be computed on the basis of 'present fair value' of the property not on the basis of 'actual legitimate cost'.

****287** The Circuit Court of Appeals also held that the Commission had no power to make findings as to past rates in aid of state regulation. But it concluded that those findings were proper as a step in the process of fixing future rates. Viewed in that light, however, the findings were deemed to be invalidated by the same errors which vitiated the findings on which the rate order was based.

Order Reducing Rates. Congress has provided in s 4(a) of the Natural Gas Act that all natural gas rates subject to the jurisdiction of the Commission 'shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.' Sec. 5(a) gives the Commission the power, after hearing, to determine the 'just and reasonable rate' to be thereafter observed and to fix the rate by order. Sec. 5(a) also empowers the Commission to order a 'decrease where existing rates are unjust * * * unlawful, or are not the lowest reasonable rates.' And Congress has provided in s 19(b) that on review of these rate orders the 'finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive.' Congress, however, has provided no formula by which the 'just and reasonable' rate is to be determined. It has not filled in the ***601** details of the general prescription FN8 of s 4(a) and s 5(a). It has not expressed in a specific rule the fixed principle of 'just and reasonable'.

FN8. Sec. 6 of the Act comes the closest to supplying any definite criteria for rate making. It provides in subsection (a) that, 'The Commission may investigate the ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.' Subsection (b) provides that every natural-gas company on request shall file with the Commission a statement of the 'original cost' of its property and shall keep the Commission informed regarding the 'cost' of all additions, etc.

[1] [2] When we sustained the constitutionality of the Natural Gas Act in the Natural Gas Pipeline Co. case, we stated that the 'authority of Congress to regulate the prices of commodities in interstate commerce is at least as great under the Fifth Amendment as is that of the states under the Fourteenth to regulate the prices of commodities in intrastate commerce.' 315 U.S. at page 582, 62 S.Ct. at page 741, 86 L.Ed. 1037. Rate-making is indeed but one species of price-fixing. Munn v. Illinois, 94 U.S. 113, 134, 24 L.Ed. 77. The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid. Block v. Hirsh, 256 U.S. 135, 155-157, 41 S.Ct. 458, 459, 460, 65 L.Ed. 865, 16 A.L.R. 165; Nebbia v. New York, 291 U.S. 502, 523-539, 54 S.Ct. 505, 509-517, 78 L.Ed. 940, 89 A.L.R. 1469, and cases cited. It does, however, indicate that 'fair value' is the end product of the process of rate-making not the starting point as the Circuit Court of Appeals held. The heart of the matter is that rates cannot be made to depend upon 'fair value' when the value of the going enterprise depends on earnings under whatever rates may be anticipated. FN9

FN9 We recently stated that the meaning of the word 'value' is to be gathered 'from the purpose for which a valuation is being made. Thus the question in a valuation for rate making is how much a utility will be allowed to earn. The basic

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question in a valuation for reorganization purposes is how much the enterprise in all probability can earn.' Institutional Investors v. Chicago, M., St. P. & P.R. Co., 318 U.S. 523, 540, 63 S.Ct. 727, 738.

***602** [3] [4] [5] [6] [7] We held in Federal Power Commission v. Natural Gas Pipeline Co., supra, that the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' Id., 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. And when the Commission's order is challenged in the courts, the question is whether that order 'viewed in its entirety' meets the requirements of the Act. Id., 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. Cf. ****288**Los Angeles Gas & Electric Corp. v. Railroad Commission, 289 U.S. 287, 304, 305, 314, 53 S.Ct. 637, 643, 644, 647, 77 L.Ed. 1180; West Ohio Gas Co. v. Public Utilities Commission (No. 1), 294 U.S. 63, 70, 55 S.Ct. 316, 320, 79 L.Ed. 761; West v. Chesapeake & Potomac Tel. Co., 295 U.S. 662, 692, 693, 55 S.Ct. 894, 906, 907, 79 L.Ed. 1640 (dissenting opinion). It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the Commission's order does not become suspect by reason of the fact that it is challenged. It is the product of expert judgment which carries a presumption of validity. And he who would upset the rate order under the Act carries the heavy burden of making a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Cf. Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 29 S.Ct. 357, 53 L.Ed. 577; Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at pages 164, 169, 54 S.Ct. at pages 663, 665, 78 L.Ed. 1182; Railroad Commission v. Pacific Gas & E. Co., 302 U.S. 388, 401, 58 S.Ct. 334, 341, 82 L.Ed. 319.

***603** [8] [9] The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745, 86 L.Ed. 1037. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346, 12 S.Ct. 400, 402, 36 L.Ed. 176. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. See State of Missouri ex rel. South-western Bell Tel. Co. v. Public Service Commission, 262 U.S. 276, 291, 43 S.Ct. 544, 547, 67 L.Ed. 981, 31 A.L.R. 807 (Mr. Justice Brandeis concurring). The conditions under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at. For we are of the view that the end result in this case cannot be condemned under the Act as unjust and unreasonable from the investor or company viewpoint.

We have already noted that Hope is a wholly owned subsidiary of the Standard Oil Co. (N.J.). It has no securities outstanding except stock. All of that stock has been owned by Standard since 1908. The par amount presently outstanding is approximately $28,000,000 as compared with the rate base of $33,712,526 established by ***604** the Commission. Of the total outstanding stock $11,000,000 was issued in stock dividends. The balance, or about $17,000,000, was issued for cash or other assets. During the four decades of its operations Hope has paid over $97,000,000 in cash dividends. It had, moreover, accumulated by 1940 an earned surplus of about $8,000,000. It had thus earned the total investment in the company nearly seven times. Down to 1940 it earned over 20% per year on the average annual amount of its capital stock issued for cash or other assets. On an average invested capital of some $23,000,000 Hope's average earnings have been about 12% a year. And during this period it had accumulated in addition reserves for depletion and depreciation of about $46,000,000. Furthermore, during 1939, 1940 and 1941, Hope paid dividends of 10% on its stock. And in the year 1942, during about half of which the lower rates were in effect, it paid dividends of 7 1/2%. From 1939-1942 its earned surplus increased from $5,250,000 to about $13,700,000, i.e., to almost half the par value of its outstanding stock.

As we have noted, the Commission fixed a rate of return which permits Hope to earn $2,191,314 annually. In determining that amount it stressed the importance of maintaining the financial integrity of the ****289** company. It considered the financial history of Hope and a vast

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array of data bearing on the natural gas industry, related businesses, and general economic conditions. It noted that the yields on better issues of bonds of natural gas companies sold in the last few years were 'close to 3 per cent', 44 P.U.R.,N.S., at page 33. It stated that the company was a 'seasoned enterprise whose risks have been minimized' by adequate provisions for depletion and depreciation (past and present) with 'concurrent high profits', by 'protected established markets, through affiliated distribution companies, in populous and industralized areas', and by a supply of gas locally to meet all requirements,***605** 'except on certain peak days in the winter, which it is feasible to supplement in the future with gas from other sources.' Id., 44 P.U.R.,N.S., at page 33. The Commission concluded, 'The company's efficient management, established markets, financial record, affiliations, and its prospective business place it in a strong position to attract capital upon favorable terms when it is required.' Id., 44 P.U.R.,N.S., at page 33.

[10] [11] [12] In view of these various considerations we cannot say that an annual return of $2,191,314 is not 'just and reasonable' within the meaning of the Act. Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, even though they might produce only a meager return on the so-called 'fair value' rate base. In that connection it will be recalled that Hope contended for a rate base of $66,000,000 computed on reproduction cost new. The Commission points out that if that rate base were accepted, Hope's average rate of return for the four-year period from 1937-1940 would amount to 3.27%. During that period Hope earned an annual average return of about 9% on the average investment. It asked for no rate increases. Its properties were well maintained and operated. As the Commission says such a modest rate of 3.27% suggests an 'inflation of the base on which the rate has been computed.' Dayton Power & Light Co. v. Public Utilities Commission, 292 U.S. 290, 312, 54 S.Ct. 647, 657, 78 L.Ed. 1267. Cf. Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at page 164, 54 S.Ct. at page 663, 78 L.Ed. 1182. The incongruity between the actual operations and the return computed on the basis of reproduction cost suggests that the Commission was wholly justified in rejecting the latter as the measure of the rate base.

In view of this disposition of the controversy we need not stop to inquire whether the failure of the Commission to add the $17,000,000 of well-drilling and other costs to ***606** the rate base was consistent with the prudent investment theory as developed and applied in particular cases.

[13] [14] [15] Only a word need be added respecting depletion and depreciation. We held in the Natural Gas Pipeline Co. case that there was no constitutional requirement 'that the owner who embarks in a wasting-asset business of limited life shall receive at the end more than he has put into it.' 315 U.S. at page 593, 62 S.C. at page 746, 86 L.Ed. 1037. The Circuit Court of Appeals did not think that that rule was applicable here because Hope was a utility required to continue its service to the public and not scheduled to end its business on a day certain as was stipulated to be true of the Natural Gas Pipeline Co. But that distinction is quite immaterial. The ultimate exhaustion of the supply is inevitable in the case of all natural gas companies. Moreover, this Court recognized in Lindheimer v. Illinois Bell Tel. Co., supra, the propriety of basing annual depreciation on cost. [FN10] By such a procedure the ****290** utility is made whole and the integrity of its investment maintained. [FN11] No more is required. [FN12] We cannot approve the contrary holding ***607** of United Railways & Electric Co. v. West, 280 U.S. 234, 253, 254, 50 S.Ct. 123, 126, 127, 74 L.Ed. 390. Since there are no constitutional requirements more exacting than the standards of the Act, a rate order which conforms to the latter does not run afoul of the former.

FN10 Chief Justice Hughes said in that case (292 U.S. at pages 168, 169, 54 S.Ct. at page 665, 78 L.Ed. 1182): 'If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.'

FN11 See Mr. Justice Brandeis (dissenting) in United Railways & Electric Co. v. West, 280 U.S. 234, 259-288, 50 S.Ct. 123, 128-138, 74 L.Ed. 390, for an extended analysis of the problem.

FN12 It should be noted that the Act provides no specific rule governing depletion and depreciation. Sec. 9(a) merely states that the

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> Commission 'may from time to time ascertain and determine, and by order fix, the proper and adequate rates of depreciation and amortization of the several classes of property of each natural-gas company used or useful in the production, transportation, or sale of natural gas.'

The Position of West Virginia. The State of West Virginia, as well as its Public Service Commission, intervened in the proceedings before the Commission and participated in the hearings before it. They have also filed a brief amicus curiae here and have participated in the argument at the bar. Their contention is that the result achieved by the rate order 'brings consequences which are unjust to West Virginia and its citizens' and which 'unfairly depress the value of gas, gas lands and gas leaseholds, unduly restrict development of their natural resources, and arbitrarily transfer their properties to the residents of other states without just compensation therefor.'

West Virginia points out that the Hope Natural Gas Co. holds a large number of leases on both producing and unoperated properties. The owner or grantor receives from the operator or grantee delay rentals as compensation for postponed drilling. When a producing well is successfully brought in, the gas lease customarily continues indefinitely for the life of the field. In that case the operator pays a stipulated gas-well rental or in some cases a gas royalty equivalent to one-eighth of the gas marketed. [FN13] Both the owner and operator have valuable property interests in the gas which are separately taxable under West Virginia law. The contention is that the reversionary interests in the leaseholds should be represented in the rate proceedings since it is their gas which is being sold in interstate ***608** commerce. It is argued, moreover, that the owners of the reversionary interests should have the benefit of the 'discovery value' of the gas leaseholds, not the interstate consumers. Furthermore, West Virginia contends that the Commission in fixing a rate for natural gas produced in that State should consider the effect of the rate order on the economy of West Virginia. It is pointed out that gas is a wasting asset with a rapidly diminishing supply. As a result West Virginia's gas deposits are becoming increasingly valuable. Nevertheless the rate fixed by the Commission reduces that value. And that reduction, it is said, has severe repercussions on the economy of the State. It is argued in the first place that as a result of this rate reduction Hope's West Virginia property taxes may be decreased in view of the relevance which earnings have under West Virginia law in the assessment of property for tax purposes. [FN14] Secondly, it is pointed out that West Virginia has a production tax [FN15] on the 'value' of the gas exported from the State. And we are told that for purposes of that tax 'value' becomes under West Virginia law 'practically the substantial equivalent of market value.' Thus West Virginia argues that undervaluation of Hope's gas leaseholds will cost the State many thousands of dollars in taxes. The effect, it is urged, is to impair West Virginia's tax structure for the benefit of Ohio and Pennsylvania consumers. West Virginia emphasizes, moreover, its deep interest in the conservation of its natural resources including its natural gas. It says that a reduction of the value of these leasehold values will jeopardize these conservation policies in three respects: (1) ****291** exploratory development of new fields will be discouraged; (2) abandonment of lowyield high-cost marginal wells will be hastened; and (3) secondary recovery of oil will be hampered. ***609** Furthermore, West Virginia contends that the reduced valuation will harm one of the great industries of the State and that harm to that industry must inevitably affect the welfare of the citizens of the State. It is also pointed out that West Virginia has a large interest in coal and oil as well as in gas and that these forms of fuel are competitive. When the price of gas is materially cheapened, consumers turn to that fuel in preference to the others. As a result this lowering of the price of natural gas will have the effect of depreciating the price of West Virginia coal and oil.

> FN13 See Simonton, The Nature of the Interest of the Grantee Under an Oil and Gas Lease (1918), 25 W.Va.L.Quar. 295.

> FN14 West Penn Power Co. v. Board of Review, 112 W.Va. 442, 164 S.E. 862.

> FN15 W.Va.Rev.Code of 1943, ch. 11. Art. 13, ss 2a, 3a.

West Virginia insists that in neglecting this aspect of the problem the Commission failed to perform the function which Congress entrusted to it and that the case should be remanded to the Commission for a modification of its order. [FN16]

> FN16 West Virginia suggests as a possible solution (1) that a 'going concern value' of the company's tangible assets be included in the rate base and (2) that the fair market value of gas delivered to customers be added to the outlay for operating expenses and taxes.

We have considered these contentions at length in view of the earnestness with which they have been urged upon us. We have searched the legislative history of the Natural

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Gas Act for any indication that Congress entrusted to the Commission the various considerations which West Virginia has advanced here. And our conclusion is that Congress did not.

[16] [17] We pointed out in Illinois Natural Gas Co. v. Central Illinois Public Service Co., 314 U.S. 498, 506, 62 S.Ct. 384, 387, 86 L.Ed. 371, that the purpose of the Natural Gas Act was to provide, 'through the exercise of the national power over interstate commerce, an agency for regulating the wholesale distribution to public service companies of natural gas moving interstate, which this Court had declared to be interstate commerce not subject to certain types of state regulation.' As stated in the House Report the 'basic purpose' of this legislation was 'to occupy' the field in which such cases as ***610**State of Missouri v. Kansas Natural Gas Co., 265 U.S. 298, 44 S.Ct. 544, 68 L.Ed. 1027, and Public Utilities Commission v. Attleboro Steam & Electric Co., 273 U.S. 83, 47 S.Ct. 294, 71 L.Ed. 549, had held the States might not act. H.Rep. No. 709, 75th Cong., 1st Sess., p. 2. In accomplishing that purpose the bill was designed to take 'no authority from State commissions' and was 'so drawn as to complement and in no manner usurp State regulatory authority.' Id., p. 2. And the Federal Power Commission was given no authority over the 'production or gathering of natural gas.' s 1(b).

[18] The primary aim of this legislation was to protect consumers against exploitation at the lands of natural gas companies. Due to the hiatus in regulation which resulted from the Kansas Natural Gas Co. case and related decisions state commissions found it difficult or impossible to discover what it cost interstate pipe-line companies to deliver gas within the consuming states; and thus they were thwarted in local regulation. H.Rep., No. 709, supra, p. 3. Moreover, the investigations of the Federal Trade Commission had disclosed that the majority of the pipe-line mileage in the country used to transport natural gas, together with an increasing percentage of the natural gas supply for pipe-line transportation, had been acquired by a handful of holding companies. [FN17] State commissions, independent producers, and communities having or seeking the service were growing quite helpless against these combinations. [FN18] These were the types of problems with which those participating in the hearings were pre-occupied. [FN19] Congress addressed itself to those specific evils.

FN17 S.Doc. 92, Pt. 84-A, ch. XII, Final Report, Federal Trade Commission to the Senate pursuant to S.Res.No. 83, 70th Cong., 1st Sess.

FN18 S.Doc. 92, Pt. 84-A, chs. XII, XIII, op. cit., supra, note 17.

FN19 See Hearings on H.R. 11662, Subcommittee of House Committee on Interstate & Foreign Commerce, 74th Cong., 2d Sess.; Hearings on H.R. 4008, House Committee on Interstate & Foreign Commerce, 75th Cong., 1st Sess.

611** The Federal Power Commission was given*292** broad powers of regulation. The fixing of 'just and reasonable' rates (s 4) with the powers attendant thereto [FN20] was the heart of the new regulatory system. Moreover, the Commission was given certain authority by s 7(a), on a finding that the action was necessary or desirable 'in the public interest,' to require natural gas companies to extend or improve their transportation facilities and to sell gas to any authorized local distributor. By s 7(b) it was given control over the abandonment of facilities or of service. And by s 7(c), as originally enacted, no natural gas company could undertake the construction or extension of any facilities for the transportation of natural gas to a market in which natural gas was already being served by another company, or sell any natural gas in such a market, without obtaining a certificate of public convenience and necessity from the Commission. In passing on such applications for certificates of convenience and necessity the Commission was told by s 7(c), as originally enacted, that it was 'the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.' The latter provision was deleted from s 7(c) when that subsection was amended by the Act of February 7, 1942, 56 Stat. 83. By that amendment limited grandfather rights were granted companies desiring to extend their facilities and services over the routes or within the area which they were already serving. Moreover, s 7(c) was broadened so as to require certificates***612** of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but in other situations as well.

FN20 The power to investigate and ascertain the 'actual legitimate cost' of property (s 6), the requirement as to books and records (s 8), control over rates of depreciation (s 9), the requirements for periodic and special reports (s 10), the broad powers of investigation (s 14) are among the chief powers supporting the rate making function.

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[19] These provisions were plainly designed to protect the consumer interests against exploitation at the hands of private natural gas companies. When it comes to cases of abandonment or of extensions of facilities or service, we may assume that, apart from the express exemptions [FN21] contained in s 7, considerations of conservation are material to the issuance of certificates of public convenience and necessity. But the Commission was not asked here for a certificate of public convenience and necessity under s 7 for any proposed construction or extension. It was faced with a determination of the amount which a private operator should be allowed to earn from the sale of natural gas across state lines through an established distribution system. Secs. 4 and 5, not s 7, provide the standards for that determination. We cannot find in the words of the Act or in its history the slightest intimation or suggestion that the exploitation of consumers by private operators through the maintenance of high rates should be allowed to continue provided the producing states obtain indirect benefits from it. That apparently was the Commission's view of the matter, for the same arguments advanced here were presented to the Commission and not adopted by it.

FN21 Apart from the grandfather clause contained in s 7(c), there is the provision of s 7(f) that a natural gas company may enlarge or extend its facilities with the 'service area' determined by the Commission without any further authorization.

We do not mean to suggest that Congress was unmindful of the interests of the producing states in their natural gas supplies when it drafted the Natural Gas Act. As we have said, the Act does not intrude on the domain traditionally reserved for control by state commissions; and the Federal Power Commission was given no authority over***613** 'the production or gathering of natural gas.' s 1(b). In addition, Congress recognized the legitimate interests of the States in the conservation of natural gas. By s 11 Congress instructed the Commission to make reports on compacts between two or more States dealing with the conservation, production and transportation of natural gas. [FN22] The Commission was also ****293** directed to recommend further legislation appropriate or necessary to carry out any proposed compact and 'to aid in the conservation of natural-gas resources within the United States and in the orderly, equitable, and economic production, transportation, and distribution of natural gas.' s 11(a). Thus Congress was quite aware of the interests of the producing states in their natural gas supplies. [FN23] But it left the protection of ***614** those interests to measures other than the maintenance of high rates to private companies. If the Commission is to be compelled to let the stockholders of natural gas companies have a feast so that the producing states may receive crumbs from that table, the present Act must be redesigned. Such a project raises questions of policy which go beyond our province.

FN22 See P.L. 117, approved July 7, 1943, 57 Stat. 383 containing an 'Interstate Compact to Conserve Oil and Gas' between Oklahoma, Texas, New Mexico, Illinois, Colorado, and Kansas.

FN23 As we have pointed out, s 7(c) was amended by the Act of February 7, 1942, 56 Stat. 83, so as to require certificates of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but to other situations as well. Considerations of conservation entered into the proposal to give the Act that broader scope. H.Rep.No. 1290, 77th Cong. 1st Sess., pp. 2, 3. And see Annual Report, Federal Power Commission (1940) pp. 79, 80; Baum, The Federal Power Commission and State Utility Regulation (1942), p. 261.
The bill amending s 7(c) originally contained a subsection (h) reading as follows: 'Nothing contained in this section shall be construed to affect the authority of a State within which natural gas is produced to authorize or require the construction or extension of facilities for the transportation and sale of such gas within such State: Provided, however, That the Commission, after a hearing upon complaint or upon its own motion, may by order forbid any intrastate construction or extension by any natural-gas company which it shall find will prevent such company from rendering adequate service to its customers in interstate or foreign commerce in territory already being served.' See Hearings on H.R. 5249, House Committee on Interstate & Foreign Commerce, 77th Cong., 1st Sess., pp. 7, 11, 21, 29, 32, 33. In explanation of its deletion the House Committee Report stated, pp. 4, 5: 'The increasingly important problems raised by the desire of several States to regulate the use of the natural gas produced therein in the interest of consumers within such States, as against the Federal power to regulate interstate commerce in the interest of both interstate and intrastate consumers, are deemed by the committee to warrant further intensive study and probably a more retailed and comprehensive plan for the handling thereof than that which would have been provided by the stricken subsection.'

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[20] It is hardly necessary to add that a limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state either to safeguard its tax revenues from that industry [FN24] or to protect the interests of those who sell their gas to the interstate operator. [FN25] The return which ****294** the Commission***615** allowed was the net return after all such charges.

FN24 We have noted that in the annual operating expenses of some $16,000.000 the Commission included West Virginia and federal taxes. And in the net increase of $421,160 over 1940 operating expenses allowed by the Commission was some $80,000 for increased West Virginia property taxes. The adequacy of these amounts has not been challenged here.

FN25 The Commission included in the aggregate annual operating expenses which it allowed some $8,500,000 for gas purchased. It also allowed about $1,400,000 for natural gas production and about $600,000 for exploration and development.

It is suggested, however, that the Commission in ascertaining the cost of Hope's natural gas production plant proceeded contrary to s 1(b) which provides that the Act shall not apply to 'the production or gathering of natural gas'. But such valuation, like the provisions for operating expenses, is essential to the rate-making function as customarily performed in this country. Cf. Smith, The Control of Power Rates in the United States and England (1932), 159 The Annals 101. Indeed s 14(b) of the Act gives the Commission the power to 'determine the propriety and reasonableness of the inclusion in operating expenses, capital, or surplus of all delay rentals or other forms of rental or compensation for unoperated lands and leases.'

It is suggested that the Commission has failed to perform its duty under the Act in that it has not allowed a return for gas production that will be enough to induce private enterprise to perform completely and efficiently its functions for the public. The Commission, however, was not oblivious of those matters. It considered them. It allowed, for example, delay rentals and exploration and development costs in operating expenses. [FN26] No serious attempt has been made here to show that they are inadequate. We certainly cannot say that they are, unless we are to substitute our opinions for the expert judgment of the administrators to whom Congress entrusted the decision. Moreover, if in light of experience they turn out to be inadequate for development of new sources of supply, the doors of the Commission are open for increased allowances. This is not an order for all time. The Act contains machinery for obtaining rate adjustments. s 4.

FN26 See note 25, supra.

[21] [22] But it is said that the Commission placed too low a rate on gas for industrial purposes as compared with gas for domestic purposes and that industrial uses should be discouraged. It should be noted in the first place that the rates which the Commission has fixed are Hope's interstate wholesale rates to distributors not interstate rates to industrial users [FN27] and domestic consumers. We hardly ***616** can assume, in view of the history of the Act and its provisions, that the resales intrastate by the customer companies which distribute the gas to ultimate consumers in Ohio and Pennsylvania are subject to the rate-making powers of the Commission. [FN28] But in any event those rates are not in issue here. Moreover, we fail to find in the power to fix 'just and reasonable' rates the power to fix rates which will disallow or discourage resales for industrial use. The Committee Report stated that the Act provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions'. H.Rep.No.709, supra, p. 3. Yet if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine which has no express statutory sanction. The same would be true if we were to hold that the wasting-asset nature of the industry required the maintenance of the level of rates so that natural gas companies could make a greater profit on each unit of gas sold. Such theories of rate-making for this industry may or may not be desirable. The difficulty is that s 4(a) and s 5(a) contain only the conventional standards of rate-making for natural gas companies. [FN29] The ***617** Act of February 7, 1942, by broadening s 7 gave the Commission some additional authority to deal with the conservation aspects of the problem. [FN30] But s 4(a) and s 5(a) were not changed. If the standard****295** of 'just and reasonable' is to sanction the maintenance of high rates by a natural gas company because they restrict the use of natural gas for certain purposes, the Act must be further amended.

FN27 The Commission has expressed doubts over its power to fix rates on 'direct sales to industries' from interstate pipelines as distinguished from 'sales for resale to the industrial customers of distributing companies.' Annual Report, Federal Power Commission (1940), p. 11.

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FN28. Sec. 1(b) of the Act provides: 'The provisions of this Act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.' And see s 2(6), defining a 'natural-gas company', and H.Rep.No. 709, supra, pp. 2, 3.

FN29 The wasting-asset characteristic of the industry was recognized prior to the Act as requiring the inclusion of a depletion allowance among operating expenses. See Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398, 404, 405, 54 S.Ct. 763, 766, 767, 78 L.Ed. 1327, 91 A.L.R. 1403. But no such theory of rate-making for natural gas companies as is now suggested emerged from the cases arising during the earlier period of regulation.

FN30 The Commission has been alert to the problems of conservation in its administration of the Act. It has indeed suggested that it might be wise to restrict the use of natural gas 'by functions rather than by areas.' Annual Report (1940) p. 79.

The Commission stated in that connection that natural gas was particularly adapted to certain industrial uses. But it added that the general use of such gas 'under boilers for the production of steam' is 'under most circumstances of very questionable social economy.' Ibid.

[23] [24] It is finally suggested that the rates charged by Hope are discriminatory as against domestic users and in favor of industrial users. That charge is apparently based on s 4(b) of the Act which forbids natural gas companies from maintaining 'any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.' The power of the Commission to eliminate any such unreasonable differences or discriminations is plain. s 5(a). The Commission, however, made no findings under s 4(b). Its failure in that regard was not challenged in the petition to review. And it has not been raised or argued here by any party. Hence the problem of discrimination has no proper place in the present decision. It will be time enough to pass on that issue when it is presented to us. Congress has entrusted the administration of the Act to the Commission not to the courts. Apart from the requirements of judicial review it is not ***618** for us to advise the Commission how to discharge its functions.

Findings as to the Lawfulness of Past Rates. As we have noted, the Commission made certain findings as to the lawfulness of past rates which Hope had charged its interstate customers. Those findings were made on the complaint of the City of Cleveland and in aid of state regulation. It is conceded that under the Act the Commission has no power to make reparation orders. And its power to fix rates admittedly is limited to those 'to be thereafter observed and in force.' s 5(a). But the Commission maintains that it has the power to make findings as to the lawfulness of past rates even though it has no power to fix those rates. FN31 However that may be, we do not think that these findings were reviewable under s 19(b) of the Act. That section gives any party 'aggrieved by an order' of the Commission a review 'of such order' in the circuit court of appeals for the circuit where the natural gas company is located or has its principal place of business or in the United States Court of Appeals for the District of Columbia. We do not think that the findings in question fall within that category.

FN31 The argument is that s 4(a) makes 'unlawful' the charging of any rate that is not just and reasonable. And s 14(a) gives the Commission power to investigate any matter 'which it may find necessary or proper in order to determine whether any person has violated' any provision of the Act. Moreover, s 5(b) gives the Commission power to investigate and determine the cost of production or transportation of natural gas in cases where it has 'no authority to establish a rate governing the transportation or sale of such natural gas.' And s 17(c) directs the Commission to 'make available to the several State commissions such information and reports as may be of assistance in State regulation of natural-gas companies.' For a discussion of these points by the Commission see 44 P.U.R.,N.S., at pages 34, 35.

[25] [26] The Court recently summarized the various types of administrative action or determination reviewable as orders under the Urgent Deficiencies Act of October 22, ***619** 1913, 28 U.S.C. ss 45, 47a, 28 U.S.C.A. ss 45, 47a, and kindred statutory provisions. Rochester Tel. Corp. v. United States, 307 U.S. 125, 59 S.Ct. 754, 83 L.Ed. 1147. It was there pointed out that where 'the order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action', it is not

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reviewable. Id., 307 U.S. at page 130, 59 S.Ct. at page 757, 83 L.Ed. 1147. The Court said, 'In view of traditional conceptions of federal judicial power, resort to the courts in these situations is either premature or wholly beyond their province.' ****296**Id., 307 U.S. at page 130, 59 S.Ct. at page 757, 83 L.Ed. 1147. And see United States v. Los Angeles s.l.r. c/o., 273 U.S. 299, 309, 310, 47 S.Ct. 413, 414, 415, 71 L.Ed. 651; Shannahan v. United States, 303 U.S. 596, 58 S.Ct. 732, 82 L.Ed. 1039. These considerations are apposite here. The Commission has no authority to enforce these findings. They are 'the exercise solely of the function of investigation.' United States v. Los Angeles & S.L.R. Co., supra, 273 U.S. at page 310, 47 S.Ct. at page 414, 71 L.Ed. 651. They are only a preliminary, interim step towards possible future action-action not by the Commission but by wholly independent agencies. The outcome of those proceedings may turn on factors other than these findings. These findings may never result in the respondent feeling the pinch of administrative action.

Reversed.

Mr. Justice ROBERTS took no part in the consideration or decision of this case.

Opinion of Mr. Justice BLACK and Mr. Justice MURPHY.

We agree with the Court's opinion and would add nothing to what has been said but for what is patently a wholly gratuitous assertion as to Constitutional law in the dissent of Mr. Justice FRANKFURTER. We refer to the statement that 'Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra (134 U.S. 418, 10 S.Ct. 462, 702, 33 L.Ed. 970), may fairly be claimed.' That was the case in which a majority of this Court was finally induced to expand the meaning ***620** of 'due process' so as to give courts power to block efforts of the state and national governments to regulate economic affairs. The present case does not afford a proper occasion to discuss the soundness of that doctrine because, as stated in Mr. Justice FRANKFURTER'S dissent, 'That issue is not here in controversy.' The salutary practice whereby courts do not discuss issues in the abstract applies with peculiar force to Constitutional questions. Since, however, the dissent adverts to a highly controversial due process doctrine and implies its acceptance by Congress, we feel compelled to say that we do not understand that Congress voluntarily has acquiesced in a Constitutional principle of government that courts, rather than legislative bodies, possess final authority over regulation of economic affairs. Even this Court has not always fully embraced that principle, and we wish to repeat that we have never acquiesced in it, and do not now. See Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 599-601, 62 S.Ct. 736, 749, 750, 86 L.Ed. 1037.

Mr. Justice REED, dissenting.

This case involves the problem of rate making under the Natural Gas Act. Added importance arises from the obvious fact that the principles stated are generally applicable to all federal agencies which are entrusted with the determination of rates for utilities. Because my views differ somewhat from those of my brethren, it may be of some value to set them out in a summary form.

The Congress may fix utility rates in situations subject to federal control without regard to any standard except the constitutional standards of due process and for taking private property for public use without just compensation. Wilson v. New, 243 U.S. 332, 350, 37 S.Ct. 298, 302, 61 L.Ed. 755, L.R.A.1917E, 938, Ann.Cas.1918A, 1024. A Commission, however, does not have this freedom of action. Its powers are limited not only by the constitutional standards but also by the standards of the delegation. Here the standard added by the Natural Gas Act is that the rate be 'just ***621** and reasonable.' [FN1] Section 6 [FN2] ****297** throws additional light on the meaning of these words.

FN1 Natural Gas Act, s 4(a), 52 Stat. 821, 822, 15 U.S.C. s 717c(a), 15 U.S.C.A. s 717c(a).

FN2 52 Stat. 821, 824, 15 U.S.C. s 717e, 15 U.S.C.A. s 717e:

'(a) The Commission may investigate and ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.

'(b) Every natural-gas company upon request shall file with the Commission an inventory of all or any part of its property and a statement of the original cost thereof, and shall keep the Commission informed regarding the cost of all additions, betterments, extensions, and new construction.'

When the phrase was used by Congress to describe allowable rates, it had relation to something ascertainable. The rates were not left to the whim of the Commission. The rates fixed would produce an annual return and that annual return was to be compared with a theoretical just and reasonable return, all risks considered, on the fair value of the property used and useful in the public service at the time of the determination.

Such an abstract test is not precise. The agency charged

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with its determination has a wide range before it could properly be said by a court that the agency had disregarded statutory standards or had confiscated the property of the utility for public use. Cf. Chicago, M. & St. P.R. Co. v. Minnesota, 134 U.S. 418, 461-466, 10 S.Ct. 462, 702, 703-705, 33 L.Ed. 970, dissent. This is as Congress intends. Rates are left to an experienced agency particularly competent by training to appraise the amount required.

The decision as to a reasonable return had not been a source of great difficulty, for borrowers and lenders reached such agreements daily in a multitude of situations; and although the determination of fair value had been troublesome, its essentials had been worked out in fairness to investor and consumer by the time of the enactment***622** of this Act. Cf. Los Angeles G. & E. Corp. v. Railroad Comm., 289 U.S. 287, 304 et seq., 53 S.Ct. 637, 643 et seq., 77 L.Ed. 1180. The results were well known to Congress and had that body desired to depart from the traditional concepts of fair value and earnings, it would have stated its intention plainly. Helvering v. Griffiths, 318 U.S. 371, 63 S.Ct. 636.

It was already clear that when rates are in dispute, 'earnings produced by rates do not afford a standard for decision.' 289 U.S. at page 305, 53 S.Ct. at page 644, 77 L.Ed. 1180. Historical cost, prudent investment and reproduction cost [FN3] were all relevant factors in determining fair value. Indeed, disregarding the pioneer investor's risk, if prudent investment and reproduction cost were not distorted by changes in price levels or technology, each of them would produce the same result. The realization from the risk of an investment in a speculative field, such as natural gas utilities, should be reflected in the present fair value. [FN4] The amount of evidence to be admitted on any point was of course in the agency's reasonable discretion, and it was free to give its own weight to these or other factors and to determine from all the evidence its own judgment as to the necessary rates.

FN3 'Reproduction cost' has been variously defined, but for rate making purposes the most useful sense seems to be, the minimum amount necessary to create at the time of the inquiry a modern plant capable of rendering equivalent service. See I Bonbright, Valuation of Property (1937) 152. Reproduction cost as the cost of building a replica of an obsolescent plant is not of real significance.

'Prudent investment' is not defined by the Court. It may mean the sum originally put in the enterprise, either with or without additional amounts from excess earnings reinvested in the business.

FN4 It is of no more than bookkeeping significance whether the Commission allows a rate of return commensurate with the risk of the original investment or the lower rate based on current risk and a capitalization reflecting the established earning power of a successful company and the probable cost of duplicating its services. Cf. American T. & T. Co. v. United States, 299 U.S. 232, 57 S.Ct. 170, 81 L.Ed. 142. But the latter is the traditional method.

***623** I agree with the Court in not imposing a rule of prudent investment alone in determining the rate base. This leaves the Commission free, as I understand it, to use any available evidence for its finding of fair value, including both prudent investment and the cost of installing at the present time an efficient system for furnishing the needed utility service.

My disagreement with the Court arises primarily from its view that it makes no ****298** difference how the Commission reached the rate fixed so long as the result is fair and reasonable. For me the statutory command to the Commission is more explicit. Entirely aside from the constitutional problem of whether the Congress could validly delegate its rate making power to the Commission, in toto and without standards, it did legislate in the light of the relation of fair and reasonable to fair value and reasonable return. The Commission must therefore make its findings in observance of that relationship.

The Federal Power Commission did not, as I construe their action, disregard its statutory duty. They heard the evidence relating to historical and reproduction cost and to the reasonable rate of return and they appraised its weight. The evidence of reproduction cost was rejected as unpersuasive, but from the other evidence they found a rate base, which is to me a determination of fair value. On that base the earnings allowed seem fair and reasonable. So far as the Commission went in appraising the property employed in the service, I find nothing in the result which indicates confiscation, unfairness or unreasonableness. Good administration of rate making agencies under this method would avoid undue delay and render revaluations unnecessary except after violent fluctuations of price levels. Rate making under this method has been subjected to criticism. But until Congress changes the standards for the agencies, these rate making bodies should continue the conventional theory of rate ***624** making. It will probably be simpler to improve present methods than to devise new ones.

But a major error, I think was committed in the disregard

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by the Commission of the investment in exploratory operations and other recognized capital costs. These were not considered by the Commission because they were charged to operating expenses by the company at a time when it was unregulated. Congress did not direct the Commission in rate making to deduct from the rate base capital investment which had been recovered during the unregulated period through excess earnings. In my view this part of the investment should no more have been disregarded in the rate base than any other capital investment which previously had been recovered and paid out in dividends or placed to surplus. Even if prudent investment throughout the life of the property is accepted as the formula for figuring the rate base, it seems to me illogical to throw out the admittedly prudent cost of part of the property because the earnings in the unregulated period had been sufficient to return the prudent cost to the investors over and above a reasonable return. What would the answer be under the theory of the Commission and the Court, if the only prudent investment in this utility had been the seventeen million capital charges which are now disallowed?

For the reasons heretofore stated, I should affirm the action of the Circuit Court of Appeals in returning the proceeding to the Commission for further consideration and should direct the Commission to accept the disallowed capital investment in determining the fair value for rate making purposes.

Mr. Justice FRANKFURTER, dissenting.
My brother JACKSON has analyzed with particularity the economic and social aspects of natural gas as well as ***625** the difficulties which led to the enactment of the Natural Gas Act, especially those arising out of the abortive attempts of States to regulate natural gas utilities. The Natural Gas Act of 1938 should receive application in the light of this analysis, and Mr. Justice JACKSON has, I believe, drawn relevant inferences regarding the duty of the Federal Power Commission in fixing natural gas rates. His exposition seems to me unanswered, and I shall say only a few words to emphasize my basic agreement with him.

For our society the needs that are met by public utilities are as truly public services as the traditional governmental functions of police and justice. They are not less so when these services are rendered by private enterprise under governmental regulation. Who ultimately determines the ways of regulation, is the decisive aspect in the public supervision of privately-owned utilities. Foreshadowed nearly sixty years ago, Railroad Commission Cases (Stone v. Farmers' Loan & Trust Co.), 116 U.S. 307, 331, 6 S.Ct. 334, 344, 388, 1191, 29 L.Ed. 636, it was decided more than fifty ****299** years ago that the final say under the Constitution lies with the judiciary and not the legislature. Chicago, etc., R. Co. v. Minnesota , 134 U.S. 418, 10 S.Ct. 462, 702, 33 L.Ed. 970.

While legal issues touching the proper distribution of governmental powers under the Constitution may always be raised, Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra, may fairly be claimed. But in any event that issue is not here in controversy. As pointed out in the opinions of my brethren, Congress has given only limited authority to the Federal Power Commission and made the exercise of that authority subject to judicial review. The Commission is authorized to fix rates chargeable for natural gas. But the rates that it can fix must be 'just and reasonable'. s 5 of the Natural Gas Act, 15 U.S.C. s 717d, 15 U.S.C.A. s 717d. Instead of making the Commission's rate determinations final, Congress***626** specifically provided for court review of such orders. To be sure, 'the finding of the Commission as to the facts, if supported by substantial evidence' was made 'conclusive', s 19 of the Act, 15 U.S.C. s 717r; 15 U.S.C.A. s 717r. But obedience of the requirement of Congress that rates be 'just and reasonable' is not an issue of fact of which the Commission's own determination is conclusive. Otherwise, there would be nothing for a court to review except questions of compliance with the procedural provisions of the Natural Gas Act. Congress might have seen fit so to cast its legislation. But it has not done so. It has committed to the administration of the Federal Power Commission the duty of applying standards of fair dealing and of reasonableness relevant to the purposes expressed by the Natural Gas Act. The requirement that rates must be 'just and reasonable' means just and reasonable in relation to appropriate standards. Otherwise Congress would have directed the Commission to fix such rates as in the judgment of the Commission are just and reasonable; it would not have also provided that such determinations by the Commission are subject to court review.

To what sources then are the Commission and the courts to go for ascertaining the standards relevant to the regulation of natural gas rates? It is at this point that Mr. Justice JACKSON'S analysis seems to me pertinent. There appear to be two alternatives. Either the fixing of natural gas rates must be left to the unguided discretion of the Commission so long as the rates it fixes do not reveal a glaringly had prophecy of the ability of a regulated utility to continue its service in the future. Or the Commission's rate orders must be founded on due consideration of all the elements of the public interest which the production and distribution of natural gas involve just because it is natural gas. These elements are reflected in the Natural Gas Act, if that Act be applied as

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an entirety. See, for ***627** instance, ss 4(a)(b)(c)(d), 6, and 11, 15 U.S.C. ss 717c(a)(b)(c)(d), 717e, and 717j, 15 U.S.C.A. ss 717c(a-d), 717e, 717j. Of course the statute is not concerned with abstract theories of ratemaking. But its very foundation is the 'public interest', and the public interest is a texture of multiple strands. It includes more than contemporary investors and contemporary consumers. The needs to be served are not restricted to immediacy, and social as well as economic costs must be counted.

It will not do to say that it must all be left to the skill of experts. Expertise is a rational process and a rational process implies expressed reasons for judgment. It will little advance the public interest to substitute for the hodge-podge of the rule in Smyth v. Ames, 169 U.S. 466, 18 S.Ct. 418, 42 L.Ed. 819, an encouragement of conscious obscurity or confusion in reaching a result, on the assumption that so long as the result appears harmless its basis is irrelevant. That may be an appropriate attitude when state action is challenged as unconstitutional. Cf. Driscoll v. Edison Light & Power Co., 307 U.S. 104, 59 S.Ct. 715, 83 L.Ed. 1134. But it is not to be assumed that it was the design of Congress to make the accommodation of the conflicting interests exposed in Mr. Justice JACKSON'S opinion the occasion for a blind clash of forces or a partial assessment of relevant factors, either before the Commission or here.

The objection to the Commission's action is not that the rates it granted were too low but that the range of its vision was too narrow. And since the issues before the Commission involved no less than the ****300** total public interest, the proceedings before it should not be judged by narrow conceptions of common law pleading. And so I conclude that the case should be returned to the Commission. In order to enable this Court to discharge its duty of reviewing the Commission's order, the Commission should set forth with explicitness the criteria by which it is guided ***628** in determining that rates are 'just and reasonable', and it should determine the public interest that is in its keeping in the perspective of the considerations set forth by Mr. Justice JACKSON.

By Mr. Justice JACKSON.

Certainly the theory of the court below that ties rate-making to the fair-value-reproduction-cost formula should be overruled as in conflict with Federal Power Commission v. Natural Gas Pipeline Co. [FN1] But the case should, I think, be the occasion for reconsideration of our rate-making doctrine as applied to natural gas and should be returned to the Commission for further consideration in the light thereof.

FN1 315 U.S. 575, 62 S.Ct. 736, 86 L.Ed. 1037.

The Commission appears to have understood the effect of the two opinions in the Pipeline case to be at least authority and perhaps direction to fix natural gas rates by exclusive application of the 'prudent investment' rate base theory. This has no warrant in the opinion of the Chief Justice for the Court, however, which released the Commission from subservience to 'any single formula or combination of formulas' provided its order, 'viewed in its entirety, produces no arbitrary result.' 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. The minority opinion I understood to advocate the 'prudent investment' theory as a sufficient guide in a natural gas case. The view was expressed in the court below that since this opinion was not expressly controverted it must have been approved. [FN2] I disclaim this imputed***629** approval with some particularity, because I attach importance at the very beginning of federal regulation of the natural gas industry to approaching it as the performance of economic functions, not as the performance of legalistic rituals.

FN2 Judge Dobie, dissenting below, pointed out that the majority opinion in the Pipeline case 'contains no express discussion of the Prudent Investment Theory' and that the concurring opinion contained a clear one, and said, 'It is difficult for me to believe that the majority of the Supreme Court, believing otherwise, would leave such a statement unchallenged.' (134 F.2d 287, 312.) The fact that two other Justices had as matter of record in our books long opposed the reproduction cost theory of rate bases and had commented favorably on the prudent investment theory may have influenced that conclusion. See opinion of Mr. Justice Frankfurter in Driscoll v. Edison Light & Power Co., 307 U.S. 104, 122, 59 S.Ct. 715, 724, 83 L.Ed. 1134, and my brief as Solicitor General in that case. It should be noted, however, that these statements were made, not in a natural gas case, but in an electric power case-a very important distinction, as I shall try to make plain.

I.

Solutions of these cases must consider eccentricities of the industry which gives rise to them and also to the Act of Congress by which they are governed.

The heart of this problem is the elusive, exhaustible, and irreplaceable nature of natural gas itself. Given sufficient money, we can produce any desired amount of railroad,

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bus, or steamship transportation, or communications facilities, or capacity for generation of electric energy, or for the manufacture of gas of a kind. In the service of such utilities one customer has little concern with the amount taken by another, one's waste will not deprive another, a volume of service and be created equal to demand, and today's demands will not exhaust or lessen capacity to serve tomorrow. But the wealth of Midas and the wit of man cannot produce or reproduce a natural gas field. We cannot even reproduce the gas, for our manufactured product has only about half the heating value per unit of nature's own. FN3

FN3 Natural gas from the Appalachian field averages about 1050 to 1150 B.T.U. content, while by-product manufactured gas is about 530 to 540. Moody's Manual of Public Utilities (1943) 1350; Youngberg, Natural Gas (1930) 7.

****301** Natural gas in some quantity is produced in twenty-four states. It is consumed in only thirty-five states, and is ***630** available only to about 7,600,000 consumers. FN4 Its availability has been more localized than that of any other utility service because it has depended more on the caprice of nature.

FN4 Sen.Rep. No. 1162, 75th Cong., 1st Sess., 2.

The supply of the Hope Company is drawn from that old and rich and vanishing field that flanks the Appalachian mountains. Its center of production is Pennsylvania and West Virginia, with a fringe of lesser production in New York, Ohio, Kentucky, Tennessee, and the north end of Alabama. Oil was discovered in commercial quantities at a depth of only 69 1/2 feet near Titusville, Pennsylvania, in 1859. Its value then was about $16 per barrel. FN5 The oil branch of the petroleum industry went forward at once, and with unprecedented speed. The area productive of oil and gas was roughed out by the drilling of over 19,000 'wildcat' wells, estimated to have cost over $222,000,000. Of these, over 18,000 or 94.9 per cent, were 'dry holes.' About five per cent, or 990 wells, made discoveries of commercial importance, 767 of them resulting chiefly in oil and 223 in gas only. FN6 Prospecting for many years was a search for oil, and to strike gas was a misfortune. Waste during this period and even later is appalling. Gas was regarded as having no commercial value until about 1882, in which year the total yield was valued only at about $75,000. FN7 Since then, contrary to oil, which has become cheaper gas in this field has pretty steadily advanced in price.

FN5 Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 78.

FN6. Id. at 62-63.

FN7. Id. at 61.

While for many years natural gas had been distributed on a small scale for lighting, FN8 its acceptance was slow, ***631** facilities for its utilization were primitive, and not until 1885 did it take on the appearance of a substantial industry. FN9 Soon monopoly of production or markets developed. FN10 To get gas from the mountain country, where it was largely found, to centers of population, where it was in demand, required very large investment. By ownership of such facilities a few corporate systems, each including several companies, controlled access to markets. Their purchases became the dominating factor in giving a market value to gas produced by many small operators. Hope is the market for over 300 such operators. By 1928 natural gas in the Appalachian field commanded an average price of 21.1 cents per m.c.f. at points of production and was bringing 45.7 cents at points of consumption. FN11 The companies which controlled markets, however, did not rely on gas purchases alone. They acquired and held in fee or leasehold great acreage in territory proved by 'wildcat' drilling. These large marketing system companies as well as many small independent owners and operators have carried on the commercial development of proved territory. The development risks appear from the estimate that up to 1928, 312,318 proved area wells had been sunk in the Appalachian field of which 48,962, or 15.7 per cent, failed to produce oil or gas in commercial quantity. FN12

FN8 At Fredonia, New York, in 1821, natural gas was conveyed from a shallow well to some thirty people. The lighthouse at Barcelona Harbor, near what is now Westfield, New York, was at about that time and for many years afterward lighted by gas that issued from a crevice. Report on Utility Corporations by Federal Trade Commission, Sen.Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 8-9.

FN9 In that year Pennsylvania enacted 'An Act to provide for the incorporation and regulation of natural gas companies.' Penn.Laws 1885, No. 32, 15 P.S. s 1981 et seq.

FN10 See Steptoe and Hoffheimer's Memorandum for Governor Cornwell of West Virginia (1917) 25 West Virginia Law Quarterly 257; see also Report on Utility Corporations by

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Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN11 Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 73.

FN12. Id. at 63.

***632** With the source of supply thus tapped to serve centers of large demand, like Pittsburgh, Buffalo, Cleveland, Youngstown, Akron, and other industrial communities, the distribution of natural gas fast became big business. Its advantages as a ****302** fuel and its price commended it, and the business yielded a handsome return. All was merry and the goose hung high for consumers and gas companies alike until about the time of the first. World War. Almost unnoticed by the consuming public, the whole Appalachian field passed its peak of production and started to decline. Pennsylvania, which to 1928 had given off about 38 per cent of the natural gas from this field, had its peak in 1905; Ohio, which had produced 14 per cent, had its peak in 1915; and West Virginia, greatest producer of all, with 45 per cent to its credit, reached its peak in 1917. FN13

FN13. Id. at 64.

Western New York and Eastern Ohio, on the fringe of the field, had some production but relied heavily on imports from Pennsylvania and West Virginia. Pennsylvania, a producing and exporting state, was a heavy consumer and supplemented her production with imports from West Virginia. West Virginia was a consuming state, but the lion's share of her production was exported. Thus the interest of the states in the North Appalachian supply was in conflict.

Competition among localities to share in the failing supply and the helplessness of state and local authorities in the presence of state lines and corporate complexities is a part of the background of federal intervention in the industry. FN14 West Virginia took the boldest measure. It legislated a priority in its entire production in favor of its own inhabitants. That was frustrated by an injunction***633** from this Court. FN15 Throughout the region clashes in the courts and conflicting decisions evidenced public anxiety and confusion. It was held that the New York Public Service Commission did not have power to classify consumers and restrict their use of gas. FN16 That Commission held that a company could not abandon a part of its territory and still serve the rest. FN17 Some courts admonished the companies to take action to protect consumers. FN18 Several courts held that companies, regardless of failing supply, must continue to take on customers, but such compulsory additions were finally held to be within the Public Service Commission's discretion. FN19 There were attempts to throw up franchises and quit the service, and municipalities resorted to the courts with conflicting results. FN20 Public service commissions of consuming states were handicapped, for they had no control of the supply. FN21

FN14 See Report on Utility Corporations by Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN15 Commonwealth of Pennsylvania v. West Virginia, 262 U.S. 553, 43 S.Ct. 658, 67 L.Ed. 1117, 32 A.L.R. 300. For conditions there which provoked this legislation, see 25 West Virginia Law Quarterly 257.

FN16 People ex rel. Pavilion Natural Gas Co. v. Public Service Commission, 188 App.Div. 36, 176 N.Y.S. 163.

FN17 Village of Falconer v. Pennsylvania Gas Company, 17 State Department Reports, N.Y., 407.

FN18 See, for example, Public Service Commission v. Iroquois Natural Gas Co., 108 Misc. 696, 178 N.Y.S. 24; Park Abbott Realty Co. v. Iroquois Natural Gas Co., 102 Misc. 266, 168 N.Y.S. 673; Public Service Commission v. Iroquois Natural Gas Co., 189 App.Div. 545, 179 N.Y.S. 230.

FN19 People ex rel. Pennsylvania Gas Co. v. Public Service Commission, 196 App.Div. 514, 189 N.Y.S. 478.

FN20 East Ohio Gas Co. v. Akron, 81 Ohio St. 33, 90 N.E. 40, 26 L.R.A., N.S., 92, 18 Ann.Cas. 332; Village of New-comerstown v. Consolidated Gas Co., 100 Ohio St. 494, 127 N.E. 414; Gress v. Village of Ft. Laramie, 100 Ohio St. 35, 125 N.E. 112, 8 A.L.R. 242; City of Jamestown v. Pennsylvania Gas Co., D.C., 263 F. 437; Id., D.C., 264 F. 1009. See, also, United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 308, 49 S.Ct. 150, 152, 73 L.Ed. 390.

FN21 The New York Public Service Commission said: 'While the transportation of natural gas through pipe lines from one state to another state is interstate commerce * * *, Congress has not taken over the regulation of

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that particular industry. Indeed, it has expressly excepted it from the operation of the Interstate Commerce Commissions Law (Interstate Commerce Commissions Law, section 1). It is quite clear, therefore, that this Commission can not require a Pennsylvania corporation producing gas in Pennsylvania to transport it and deliver it in the State of New York, and that the Interstate Commerce Commission is likewise powerless. If there exists such a power, and it seems that there does, it is a power vested in Congress and by it not yet exercised. There is no available source of supply for the Crystal City Company at present except through purchasing from the Porter Gas Company. It is possible that this Commission might fix a price at which the Potter Gas Company should sell if it sold at all, but as the Commission can not require it to supply gas in the State of New York, the exercise of such a power to fix the price, if such power exists, would merely say, sell at this price or keep out of the State.' Lane v. Crystal City Gas Co., 8 New York Public Service Comm.Reports, Second District, 210, 212.

****303 *634** Shortages during World War I occasioned the first intervention in the natural gas industry by the Federal Government. Under Proclamation of President Wilson the United States Fuel Administrator took control, stopped extensions, classified consumers and established a priority for domestic over industrial use. [FN22] After the war federal control was abandoned. Some cities once served with natural gas became dependent upon mixed gas of reduced heating value and relatively higher price. [FN23]

FN22 Proclamation by the President of September 16, 1918; Rules and Regulations of H. A. Garfield, Fuel Administrator, September 24, 1918.

FN23 For example, the Iroquois Gas Corporation which formerly served Buffalo, New York, with natural gas ranging from 1050 to 1150 b.t.u. per cu. ft., now mixes a by-product gas of between 530 and 540 b.t.u. in proportions to provide a mixed gas of about 900 b.t.u. per cu. ft. For space heating or water heating its charges range from 65 cents for the first m.c.f. per month to 55 cents for all above 25 m.c.f. per month. Moody's Manual of Public Utilities (1943) 1350.

Utilization of natural gas of highest social as well as economic return is domestic use for cooking and water ***635** heating, followed closely by use for space heating in homes. This is the true public utility aspect of the enterprise, and its preservation should be the first concern of regulation. Gas does the family cooking cheaper than any other fuel. [FN24] But its advantages do not end with dollars and cents cost. It is delivered without interruption at the meter as needed and is paid for after it is used. No money is tied up in a supply, and no space is used for storage. It requires no handling, creates no dust, and leaves no ash. It responds to thermostatic control. It ignites easily and immediately develops its maximum heating capacity. These incidental advantages make domestic life more liveable.

FN24 The United States Fuel Administration made the following cooking value comparisons, based on tests made in the Department of Home Economics of Ohio State University:
Natural gas at 1.12 per M. is equivalent to coal at $6.50 per ton.
Natural gas at 2.00 per M. is equivalent to gasoline at 27¢ per gal.
Natural gas at 2.20 per M. is equivalent to electricity at 3¢ per k.w.h.
Natural gas at 2.40 per M. is equivalent to coal oil at 15¢ per gal.
Use and Conservation of Natural Gas, issued by U.S. Fuel Administration (1918) 5.

Industrial use is induced less by these qualities than by low cost in competition with other fuels. Of the gas exported from West Virginia by the Hope Company a very substantial part is used by industries. This wholesale use speeds exhaustion of supply and displaces other fuels. Coal miners and the coal industry, a large part of whose costs are wages, have complained of unfair competition from low-priced industrial gas produced with relatively little labor cost. [FN25]

FN25 See Brief on Behalf jof Legislation Imposing an Excise Tax on Natural Gas, submitted to N.R.A. by the United Mine Workers of America and the National Coal Association.

Gas rate structures generally have favored industrial users. In 1932, in Ohio, the average yield on gas for domestic consumption was 62.1 cents per m.c.f. and on industrial,***636** 38.7. In Pennsylvania, the figures were 62.9 against 31.7. West Virginia showed the least spread, domestic consumers paying 36.6 cents; and industrial, 27.7. [FN26] Although this spread is less than ****304** in other parts of the United States, [FN27] it can hardly be said to be

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self-justifying. It certainly is a very great factor in hastening decline of the natural gas supply.

FN26 Brief of National Gas Association and United Mine Workers, supra, note 26, pp. 35, 36, compiled from Bureau of Mines Reports.

FN27 From the source quoted in the preceding note the spread elsewhere is shown to be:

State.	Industrial	Domestic
Illinois.	29.2	1.678
Louisiana.	10.4	59.7
Oklahoma.	11.2	41.5
Texas.	13.1	59.7
Alabama.	17.8	1.227
Georgia.	22.9	1.043

About the time of World War I there were occasional and short-lived efforts by some hard-pressed companies to reverse this discrimination and adopt graduated rates, giving a low rate to quantities adequate for domestic use and graduating it upward to discourage industrial use. FN28 ***637** These rates met opposition from industrial sources, of course, and since diminished revenues from industrial sources tended to increase the domestic price, they met little popular or commission favor. The fact is that neither the gas companies nor the consumers nor local regulatory bodies can be depended upon to conserve gas. Unless federal regulation will take account of conservation, its efforts seem, as in this case, actually to constitute a new threat to the life of the Appalachian supply.

FN28 In Corning, New York, rates were initiated by the Crystal City Gas Company as follows: 70¢ for the first 5,000 cu. ft. per month; 80¢ from 5,000 to 12,000; $1 for all over 12,000. The Public Service Commission rejected these rates and fixed a flat rate of 58¢ per m.c.f. Lane v. Crystal City Gas Co., 8 New York Public Service Comm. Reports, Second District, 210.
The Pennsylvania Gas Company (National Fuel Gas Company group) also attempted a sliding scale rate for New York consumers, net per month as follows: First 5,000 feet, 35¢ ; second 5,000 feet, 45¢ ; third 5,000 feet, 50¢ ; all above 15,000, 55¢ . This was eventually abandoned, however. The company's present scale in Pennsylvania appears to be reversed to the following net monthly rate; first 3 m.c.f., 75¢ ; next 4 m.c.f., 60¢ ; next 8 m.c.f., 55¢ ; over 15 m.c.f., 50¢ . Moody's Manual of Public Utilities (1943) 1350. In New York it now serves a mixed gas.
For a study of effect of sliding scale rates in reducing consumption see 11 Proceedings of Natural Gas Association of America (1919) 287.

II.

Congress in 1938 decided upon federal regulation of the industry. It did so after an exhaustive investigation of all aspects including failing supply and competition for the use of natural gas intensified by growing scarcity. FN29 Pipelines from the Appalachian area to markets were in the control of a handful of holding company systems. FN30 This created a highly concentrated control of the producers' market and of the consumers' supplies. While holding companies dominated both production and distribution they segregated those activities in separate ***638** subsidiaries, FN31 the effect of which, if not the purpose, was to isolate ****305** some end of the business from the reach of any one state commission. The cost of natural gas to consumers moved steadily upwards over the years, out of proportion to prices of oil, which, except for the element of competition, is produced under somewhat comparable conditions. The public came to feel that the companies were exploiting the growing scarcity of local gas. The problems of this region had much to do with creating the demand for federal regulation.

FN29 See Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN30 Four holding company systems control over 55 per cent of all natural gas transmission lines in the United States. They are Columbia Gas and Electric Corporation, Cities Service Co., Electric Bond and Share Co., and Standard Oil Co. of New Jersey. Columbia alone controls nearly 25 per cent, and fifteen companies account for over 80 per cent of the total. Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 28.
In 1915, so it was reported to the Governor of West

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Virginia, 87 per cent of the total gas production of that state was under control of eight companies. Steptoe and Hoffheimer, Legislative Regulation of Natural Gas Supply in West Virginia, 17 West Virginia Law Quarterly 257, 260. Of these, three were subsidiaries of the Columbia system and others were subsidiaries of larger systems. In view of inter-system sales and interlocking interests it may be doubted whether there is much real competition among these companies.

FN31 This pattern with its effects on local regulatory efforts will be observed in our decisions. See United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 49 S.Ct. 150, 73 L.Ed. 390; United Fuel Gas Co. v. Public Service Commission, 278 U.S. 322, 49 S.Ct. 157, 73 L.Ed. 402; Dayton Power & Light v. Public Utilities Commission, 292 U.S. 290, 54 S.Ct. 647, 78 L.Ed. 1267; Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398, 54 S.Ct. 763, 78 L.Ed. 1327, 91 A.L.R. 1403, and the present case.

The Natural Gas Act declared the natural gas business to be 'affected with a public interest,' and its regulation 'necessary in the public interest.' FN32 Originally, and at the time this proceeding was commenced and tried, it also declared 'the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.' FN33 While this was later dropped, there is nothing to indicate that it was not and is not still an accurate statement of purpose of the Act. Extension or improvement of facilities may be ordered when 'necessary or desirable in the public interest,' abandonment of facilities may be ordered when the supply is 'depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity ***639** permit' abandonment and certain extensions can only be made on finding of 'the present or future public convenience and necessity.' FN34 The Commission is required to take account of the ultimate use of the gas. Thus it is given power to suspend new schedules as to rates, charges, and classification of services except where the schedules are for the sale of gas 'for resale for industrial use only,' FN35 which gives the companies greater freedom to increase rates on industrial gas than on domestic gas. More particularly, the Act expressly forbids any undue preference or advantage to any person or 'any unreasonable difference in rates * * * either as between localities or as between classes of service.' FN36 And the power of the Commission expressly includes that to determine the 'just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force.' FN37

FN32 15 U.S.C. s 717(a), 15 U.S.C.A. s 717(a). (Italics supplied throughout this paragraph.)

FN33 s 7(c), 52 Stat. 825, 15 U.S.C.A. s 717f(c).

FN34 15 U.S.C. s 717f, 15 U.S.C.A. s 717f.

FN35 Id., s 717c(e).

FN36 Id., s 717c(b).

FN37 Id., s 717d(a).

In view of the Court's opinion that the Commission in administering the Act may ignore discrimination, it is interesting that in reporting this Bill both the Senate and the House Committees on Interstate Commerce pointed out that in 1934, on a nationwide average the price of natural gas per m.c.f. was 74.6 cents for domestic use, 49.6 cents for commercial use, and 16.9 for industrial use. FN38 I am not ready to think that supporters of a bill called attention to the striking fact that householders were being charged five times as much for their gas as industrial users only as a situation which the Bill would do nothing to remedy. On the other hand the Act gave to the Commission what the Court aptly describes as 'broad powers of regulation.'

FN38 Sen. Rep. No. 1162, 75th Cong., 1st Sess. 2.

***640** III.

This proceeding was initiated by the Cities of Cleveland and Akron. They alleged that the price charged by Hope for natural gas 'for resale to domestic, commercial and small industrial consumers in Cleveland and elsewhere is excessive, unjust, unreasonable, greatly in excess of the price charged by Hope to nonaffiliated companies at wholesale for resale to domestic, commercial and small industrial consumers, and greatly in excess of the price charged by Hope to East Ohio for resale to certain favored industrial consumers in Ohio, and therefore is further unduly discriminatory between consumers and between classes of service' (italics supplied). The company answered admitting differences in prices to affiliated and nonaffiliated companies and justifying them by differences in conditions of delivery.****306** As to the allegation that the contract price is 'greatly in excess of the price charged by Hope to East Ohio for resale to

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certain favored industrial consumers in Ohio,' Hope did not deny a price differential, but alleged that industrial gas was not sold to 'favored consumers' but was sold under contract and schedules filed with and approved by the Public Utilities Commission of Ohio, and that certain conditions of delivery made it not 'unduly discriminatory.'

The record shows that in 1940 Hope delivered for industrial consumption 36,523,792 m.c.f. and for domestic and commercial consumption, 50,343,652 m.c.f. I find no separate figure for domestic consumption. It served 43,767 domestic consumers directly, 511,521 through the East Ohio Gas Company, and 154,043 through the Peoples Natural Gas Company, both affiliates owned by the same parent. Its special contracts for industrial consumption, so far as appear, are confined to about a dozen big industries.

***641** Hope is responsible for discrimination as exists in favor of these few industrial consumers. It controls both the resale price and use of industrial gas by virtue of the very interstate sales contracts over which the Commission is exercising its jurisdiction.

Hope's contract with East Ohio Company is an example. Hope agrees to deliver, and the Ohio Company to take, '(a) all natural gas requisite for the supply of the domestic consumers of the Ohio Company; (b) such amounts of natural gas as may be requisite to fulfill contracts made with the consent and approval of the Hope Company by the Ohio Company, or companies which it supplies with natural gas, for the sale of gas upon special terms and conditions for manufacturing purposes.' The Ohio company is required to read domestic customers' meters once a month and meters of industrial customers daily and to furnish all meter readings to Hope. The Hope Company is to have access to meters of all consumers and to all of the Ohio Company's accounts. The domestic consumers of the Ohio Company are to be fully supplied in preference to consumers purchasing for manufacturing purposes and 'Hope Company can be required to supply gas to be used for manufacturing purposes only where the same is sold under special contracts which have first been submitted to and approved in writing by the Hope Company and which expressly provide that natural gas will be supplied thereunder only in so far as the same is not necessary to meet the requirements of domestic consumers supplied through pipe lines of the Ohio Company.' This basic contract was supplemented from time to time, chiefly as to price. The last amendment was in a letter from Hope to East Ohio in 1937. It contained a special discount on industrial gas and a schedule of special industrial contracts, Hope reserving the right to make eliminations therefrom and agreeing that others might be added from time to ***642** time with its approval in writing. It said, 'It is believed that the price concessions contained in this letter, while not based on our costs, are under certain conditions, to our mutual advantage in maintaining and building up the volumes of gas sold by us (italics supplied).' [FN39]

FN39 The list of East Ohio Gas Company's special industrial contracts thus expressly under Hope's control and their demands are as follows:

****307** The Commission took no note of the charges of discrimination and made no disposition of the issue tendered on this point. It ordered a flat reduction in the price per m.c.f. of all gas delivered by Hope in interstate commerce. It made no limitation, condition, or provision as to what classes of consumers should get the benefit of the reduction. While the cities have accepted and are defending the reduction, it is my view that the discrimination of which they have complained is perpetuated and increased by the order of the Commission and that it violates the Act in so doing.

The Commission's opinion aptly characterizes its entire objective by saying that 'bona fide investment figures now become all-important in the regulation of rates.' It should be noted that the all-importance of this theory is not the result of any instruction from Congress. When the Bill to regulate gas was first before Congress it contained***643** the following: 'In determining just and reasonable rates the Commission shall fix such rate as will allow a fair return upon the actual legitimate prudent cost of the property used and useful for the service in question.' H.R. 5423, 74th Cong., 1st Sess. Title III, s 312(c). Congress rejected this language. See H.R. 5423, s 213 (211(c)), and H.R. Rep. No. 1318, 74th Cong., 1st Sess. 30.

The Commission contends nevertheless that the 'all important' formula for finding a rate base is that of prudent investment. But it excluded from the investment base an amount actually and admittedly invested of some $17,000,000. It did so because it says that the Company recouped these expenditures from customers before the days of regulation from earnings above a fair return. But it would not apply all of such 'excess earnings' to reduce the rate base as one of the Commissioners suggested. The reason for applying excess earnings to reduce the investment base roughly from $69,000,000 to $52,000,000 but refusing to apply them to reduce it from that to some $18,000,000 is not found in a difference in the character of the earnings or in their reinvestment. The reason assigned is a difference in bookkeeping treatment many years before the Company was subject to regulation. The $17,000,000, reinvested chiefly in well

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drilling, was treated on the books as expense. (The Commission now requires that drilling costs be carried to capital account.) The allowed rate base thus actually was determined by the Company's bookkeeping, not its investment. This attributes a significance to formal classification in account keeping that seems inconsistent with rational rate regulation. [FN40] Of ***644** course, the ****308** Commission would not and should not allow a rate base to be inflated by bookkeeping which had improperly capitalized expenses. I have doubts about resting public regulation upon any rule that is to be used or not depending on which side it favors.

FN40 To make a fetish of mere accounting is to shield from examination the deeper causes, forces, movements, and conditions which should govern rates. Even as a recording of current transactions, bookkeeping is hardly an exact science. As a representation of the condition and trend of a business, it uses symbols of certainty to express values that actually are in constant flux. It may be said that in commercial or investment banking or any business extending credit success depends on knowing what not to believe in accounting. Few concerns go into bankruptcy or reorganization whose books do not show them solvent and often even profitable. If one cannot rely on accountancy accurately to disclose past or current conditions of a business, the fallacy of using it as a sole guide to future price policy ought to be apparent. However, our quest for certitude is so ardent that we pay an irrational reverence to a technique which uses symbols of certainty, even though experience again and again warns us that they are delusive. Few writers have ventured to challenge this American idolatry, but see Hamilton, Cost as a standard for Price, 4 Law and Contemporary Problems 321, 323-25. He observes that 'As the apostle would put it, accountancy is all things to all men. * * * Its purpose determines the character of a system of accounts.' He analyzes the hypothetical character of accounting and says 'It was no eternal mold for pecuniary verities handed down from on high. It was-like logic or algebra, or the device of analogy in the law-an ingenious contrivance of the human mind to serve a limited and practical purpose.' 'Accountancy is far from being a pecuniary expression of all that is industrial reality. It is an instrument, highly selective in its application, in the service of the institution of money making.' As to capital account he observes 'In an enterprise in lusty competition with others of its kind, survival is the thing and the system of accounts has its focus in solvency. * * * Accordingly depreciation, obsolescence, and other factors which carry no immediate threat are matters of lesser concern and the capital account is likely to be regarded as a secondary phenomenon. * * * But in an enterprise, such as a public utility, where continued survival seems assured, solvency is likely to be taken for granted. * * * A persistent and ingenious attention is likely to be directed not so much to securing the upkeep of the physical property as to making it certain that capitalization fails in not one whit to give full recognition to every item that should go into the account.'

***645** The Company on the other hand, has not put its gas fields into its calculations on the present-value basis, although that, it contends, is the only lawful rule for finding a rate base. To do so would result in a rate higher than it has charged or proposes as a matter of good business to charge.

The case before us demonstrates the lack of rational relationship between conventional rate-base formulas and natural gas production and the extremities to which regulating bodies are brought by the effort to rationalize them. The Commission and the Company each stands on a different theory, and neither ventures to carry its theory to logical conclusion as applied to gas fields.

IV.

This order is under judicial review not because we interpose constitutional theories between a State and the business it seeks to regulate, but because Congress put upon the federal courts a duty toward administration of a new federal regulatory Act. If we are to hold that a given rate is reasonable just because the Commission has said it was reasonable, review becomes a costly, time-consuming pageant of no practical value to anyone. If on the other hand we are to bring judgment of our own to the task, we should for the guidance of the regulators and the regulated reveal something of the philosophy, be it legal or economic or social, which guides us. We need not be slaves to a formula but unless we can point out a rational way of reaching our conclusions they can only be accepted as resting on intuition or predilection. I must admit that I possess no instinct jby which to know the 'reasonable' from the 'unreasonable' in prices and must seek some conscious design for decision.

The Court sustains this order as reasonable, but what makes it so or what could possibly make it otherwise,

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***646** I cannot learn. It holds that: 'it is the result reached not the method employed which is controlling'; 'the fact that the method employed to reach that result may contain infirmities is not then important' and it is not 'important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at.' The Court does lean somewhat on considerations of capitalization and dividend history and requirements for dividends on outstanding stock. But I can give no real weight to that for it is generally and I think deservedly in discredit as any guide in rate cases. FN41

FN41 See 2 Bonbright, Valuation of Property (1937) 1112.

Our books already contain so much talk of methods of rationalizing rates that we must appear ambiguous if we announce results without our working methods. We are confronted with regulation of a unique type of enterprise which I think requires considered rejection of much conventional utility doctrine and adoption of concepts of 'just and reasonable' rates and practices and of the 'public interest' that will take account of the peculiarities of the business.

The Court rejects the suggestions of this opinion. It says that the Committees in reporting the bill which became the Act said it provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions.' So saying it sustains a rate calculated on a novel variation of a rate base theory which itself had at the time of enactment of the legislation been recognized only in dissenting opinions. Our difference seems to be between unconscious innovation, FN42 and the purposeful ****309** and deliberate innovation I ***647** would make to meet the necessities of regulating the industry before us.

FN42 Bonbright says, '* * * the vice of traditional law lies, not in its adoption of excessively rigid concepts of value and rules of valuation, but rather in its tendency to permit shifts in meaning that are inept, or else that are ill-defined because the judges that make them will not openly admit that they are doing so.' Id., 1170.

Hope's business has two components of quite divergent character. One, while not a conventional common-carrier undertaking, is essentially a transportation enterprise consisting of conveying gas from where it is produced to point of delivery to the buyer. This is a relatively routine operation not differing substantially from many other utility operations. The service is produced by an investment in compression and transmission facilities. Its risks are those of investing in a tested means of conveying a discovered supply of gas to a known market. A rate base calculated on the prudent investment formula would seem a reasonably satisfactory measure for fixing a return from that branch of the business whose service is roughly proportionate to the capital invested. But it has other consequences which must not be overlooked. It gives marketability and hence 'value' to gas owned by the company and gives the pipeline company a large power over the marketability and hence 'value' of the production of others.

The other part of the business-to reduce to possession an adequate supply of natural gas-is of opposite character, being more erratic and irregular and unpredictable in relation to investment than any phase of any other utility business. A thousand feet of gas captured and severed from real estate for delivery to consumers is recognized under our law as property of much the same nature as a ton of coal, a barrel of oil, or a yard of sand. The value to be allowed for it is the real battleground between the investor and consumer. It is from this part of the business that the chief difference between the parties as to a proper rate base arises.

It is necessary to a 'reasonable' price for gas that it be anchored to a rate base of any kind? Why did courts in the first place begin valuing 'rate bases' in order to 'value' something else? The method came into vogue ***648** in fixing rates for transportation service which the public obtained from common carriers. The public received none of the carriers' physical property but did make some use of it. The carriage was often a monopoly so there were no open market criteria as to reasonableness. The 'value' or 'cost' of what was put to use in the service by the carrier was not a remote or irrelevant consideration in making such rates. Moreover the difficulty of appraising an intangible service was thought to be simplified if it could be related to physical property which was visible and measurable and the items of which might have market value. The court hoped to reason from the known to the unknown. But gas fields turn this method topsy turvy. Gas itself is tangible, possessible, and does have a market and a price in the field. The value of the rate base is more elusive than that of gas. It consists of intangibles-leaseholds and freeholds-operated and unoperated-of little use in themselves except as rights to reach and capture gas. Their value lies almost wholly in predictions of discovery, and of price of gas when captured, and bears little relation to cost of tools and supplies and labor to develop it. Gas is what Hope sells and it can be directly priced more reasonably and easily and accurately than the

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components of a rate base can be valued. Hence the reason for resort to a roundabout way of rate base price fixing does not exist in the case of gas in the field.

But if found, and by whatever method found, a rate base is little help in determining reasonableness of the price of gas. Appraisal of present value of these intangible rights to pursue fugitive gas depends on the value assigned to the gas when captured. The 'present fair value' rate base, generally in ill repute, FN43 is not even ****310** urged by the gas company for valuing its fields.

> FN43 'The attempt to regulate rates by reference to a periodic or occasional reappraisal of the properties has now been tested long enough to confirm the worst fears of its critics. Unless its place is taken by some more promising scheme of rate control, the days of private ownership under government regulation may be numbered.' 2 Bonbright, Valuation of Property (1937) 1190.

***649** The prudent investment theory has relative merits in fixing rates for a utility which creates its service merely by its investment. The amount and quality of service rendered by the usual utility will, at least roughly, be measured by the amount of capital it puts into the enterprise. But it has no rational application where there is no such relationship between investment and capacity to serve. There is no such relationship between investment and amount of gas produced. Let us assume that Doe and Roe each produces in West Virginia for delivery to Cleveland the same quantity of natural gas per day. Doe, however, through luck or foresight or whatever it takes, gets his gas from investing $50,000 in leases and drilling. Roe drilled poorer territory, got smaller wells, and has invested $250,000. Does anybody imagine that Roe can get or ought to get for his gas five times as much as Doe because he has spent five times as much? The service one renders to society in the gas business is measured by what he gets out of the ground, not by what he puts into it, and there is little more relation between the investment and the results than in a game of poker.

Two-thirds of the gas Hope handles it buys from about 340 independent producers. It is obvious that the principle of rate-making applied to Hope's own gas cannot be applied, and has not been applied, to the bulk of the gas Hope delivers. It is not probable that the investment of any two of these producers will bear the same ratio to their investments. The gas, however, all goes to the same use, has the same utilization value and the same ultimate price.

To regulate such an enterprise by undiscriminatingly transplanting any body of rate doctrine conceived and ***650** adapted to the ordinary utility business can serve the 'public interest' as the Natural Gas Act requires, if at all, only by accident. Mr. Justice Brandeis, the pioneer juristic advocate of the prudent investment theory for man-made utilities, never, so far as I am able to discover, proposed its application to a natural gas case. On the other hand, dissenting in Commonwealth of Pennsylvania v. West Virginia, he reviewed the problems of gas supply and said, 'In no other field of public service regulation is the controlling body confronted with factors so baffling as in the natural gas industry, and in none is continuous supervision and control required in so high a degree.' 262 U.S. 553, 621, 43 S.Ct. 658, 674, 67 L.Ed. 1117, 32 A.L.R. 300. If natural gas rates are intelligently to be regulated we must fit our legal principles to the economy of the industry and not try to fit the industry to our books.

As our decisions stand the Commission was justified in believing that it was required to proceed by the rate base method even as to gas in the field. For this reason the Court may not merely wash its hands of the method and rationale of rate making. The fact is that this Court, with no discussion of its fitness, simply transferred the rate base method to the natural gas industry. It happened in Newark Natural Gas & Fuel Co. v. City of Newark, Ohio, 1917, 242 U.S. 405, 37 S.Ct. 156, 157, 61 L.Ed. 393, Ann.Cas.1917B, 1025, in which the company wanted 25 cents per m.c.f., and under the Fourteenth Amendment challenged the reduction to 18 cents by ordinance. This Court sustained the reduction because the court below 'gave careful consideration to the questions of the value of the property * * * at the time of the inquiry,' and whether the rate 'would be sufficient to provide a fair return on the value of the property.' The Court said this method was 'based upon principles thoroughly established by repeated secisions of this court,' citing many cases, not one of which involved natural gas or a comparable wasting natural resource. Then came issues as to state power to ***651** regulate as affected by the commerce clause. Public Utilities Commission v. Landon, 1919, 249 U.S. 236, 39 S.Ct. 268, 63 L.Ed. 577; Pennsylvania Gas Co. v. Public Service Commission, 1920, 252 U.S. 23, 40 S.Ct. 279, 64 L.Ed. 434. These questions settled, the Court again was called upon in natural gas cases to consider state rate-making claimed to be invalid under the Fourteenth Amendment. United Fuel Gas Co. v. Railroad Commission of Kentucky, 1929, 278 U.S. 300, 49 S.Ct. 150, 73 L.Ed. 390; United Fuel Gas Company v. Public Service Commission of West Virginia, 1929, 278 U.S. 322, 49 S.Ct. 157, 73 L.Ed. 402. Then, as now, the differences were 'due ****311** chiefly to the difference in value ascribed by each to the gas rights and leaseholds.' 278 U.S. 300, 311, 49 S.Ct. 150, 153, 73 L.Ed. 390. No one seems to have questioned that the rate

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base method must be pursued and the controversy was at what rate base must be used. Later the 'value' of gas in the field was questioned in determining the amount a regulated company should be allowed to pay an affiliate therefor-a state determination also reviewed under the Fourteenth Amendment. Dayton Power & Light Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 290, 54 S.Ct. 647, 78 L.Ed. 1267; Columbus Gas & Fuel Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 398, 54 S.Ct. 763, 78 L.Ed. 1327, 91 A.L.R. 1403. In both cases, one of which sustained, and one of which struck down a fixed rate the Court assumed the rate base method, as the legal way of testing reasonableness of natural gas prices fixed by public authority, without examining its real relevancy to the inquiry.

Under the weight of such precedents we cannot expect the Commission to initiate economically intelligent methods of fixing gas prices. But the Court now faces a new plan of federal regulation based on the power to fix the price at which gas shall be allowed to move in interstate commerce. I should now consider whether these rules devised under the Fourteenth Amendment are the exclusive tests of a just and reasonable rate under the federal statute, inviting reargument directed to that point ***652** if necessary. As I see it now I would be prepared to hold that these rules do not apply to a natural gas case arising under the Natural Gas Act.

Such a holding would leave the Commission to fix the price of gas in the field as one would fix maximum prices of oil or milk or coal, or any other commodity. Such a price is not calculated to produce a fair return on the synthetic value of a rate base of any individual producer, and would not undertake to assure a fair return to any producer. The emphasis would shift from the producer to the product, which would be regulated with an eye to average or typical producing conditions in the field.

Such a price fixing process on economic lines would offer little temptation to the judiciary to become back seat drivers of the price fixing machine. The unfortunate effect of judicial intervention in this field is to divert the attention of those engaged in the process from what is economically wise to what is legally permissible. It is probable that price reductions would reach economically unwise and self-defeating limits before they would reach constitutional ones. Any constitutional problems growing out of price fixing are quite different than those that have heretofore been considered to inhere in rate making. A producer would have difficulty showing the invalidity of such a fixed price so long as he voluntarily continued to sell his product in interstate commerce. Should he withdraw and other authority be invoked to compel him to part with his property, a different problem would be presented.

Allowance in a rate to compensate for gas removed from gas lands, whether fixed as of point of production or as of point of delivery, probably best can be measured by a functional test applied to the whole industry. For good or ill we depend upon private enterprise to exploit these natural resources for public consumption. The function which an allowance for gas in the field should perform ***653** for society in such circumstances is to be enough and no more than enough to induce private enterprise completely and efficiently to utilize gas resources, to acquire for public service any available gas or gas rights and to deliver gas at a rate and for uses which will be in the future as well as in the present public interest.

The Court fears that 'if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine * * *.' With due deference I suggest that there is nothing novel in the idea that any change in price of a service or commodity reacts to encourage or discourage its use. The question is not whether such consequences will or will not follow; the question is whether effects must be suffered blindly or may be intelligently selected, whether price control shall have targets at which it deliberately aims or shall be handled like a gun in the hands of one who does not know it is loaded.

We should recognize 'price' for what it is-a tool, a means, an expedient. In public****312** hands it has much the same economic effects as in private hands. Hope knew that a concession in industrial price would tend to build up its volume of sales. It used price as an expedient to that end. The Commission makes another cut in that same price but the Court thinks we should ignore the effect that it will have on exhaustion of supply. The fact is that in natural gas regulation price must be used to reconcile the private property right society has permitted to vest in an important natural resource with the claims of society upon it-price must draw a balance between wealth and welfare.

To carry this into techniques of inquiry is the task of the Commissioner rather than of the judge, and it certainly is no task to be solved by mere bookkeeping but requires the best economic talent available. There would doubtless be inquiry into the price gas is bringing in the ***654** field, how far that price is established by arms' length bargaining and how far it may be influenced by agreements in restraint of trade or monopolistic influences. What must Hope really pay to get and to replace gas it delivers under this order? If it should get more or less than that for its own, how much and why? How far are such prices influenced by pipe line access to

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markets and if the consumers pay returns on the pipe lines how far should the increment they cause go to gas producers? East Ohio is itself a producer in Ohio. [FN44] What do Ohio authorities require Ohio consumers to pay for gas in the field? Perhaps these are reasons why the Federal Government should put West Virginia gas at lower or at higher rates. If so what are they? Should East Ohio be required to exploit its half million acres of unoperated reserve in Ohio before West Virginia resources shall be supplied on a devalued basis of which that State complains and for which she threatens measures of self keep? What is gas worth in terms of other fuels it displaces?

FN44 East Ohio itself owns natural gas rights in 550,600 acres, 518,526 of which are reserved and 32,074 operated, by 375 wells. Moody's Manual of Public Utilities (1943) 5.

A price cannot be fixed without considering its effect on the production of gas. Is it an incentive to continue to exploit vast unoperated reserves? Is it conducive to deep drilling tests the result of which we may know only after trial? Will it induce bringing gas from afar to supplement or even to substitute for Appalachian gas? [FN45] Can it be had from distant fields as cheap or cheaper? If so, that competitive potentiality is certainly a relevant consideration. Wise regulation must also consider, as a private buyer would, what alternatives the producer has ***655** if the price is not acceptable. Hope has intrastate business and domestic and industrial customers. What can it do by way of diverting its supply to intrastate sales? What can it do by way of disposing of its operated or reserve acreage to industrial concerns or other buyers? What can West Virginia do by way of conservation laws, severance or other taxation, if the regulated rate offends? It must be borne in mind that while West Virginia was prohibited from giving her own inhabitants a priority that discriminated against interstate commerce, we have never yet held that a good faith conservation act, applicable to her own, as well as to others, is not valid. In considering alternatives, it must be noted that federal regulation is very incomplete, expressly excluding regulation of 'production or gathering of natural gas,' and that the only present way to get the gas seems to be to call it forth by price inducements. It is plain that there is a downward economic limit on a safe and wise price.

FN45 Hope has asked a certificate of convenience and necessity to lay 1140 miles of 22-inch pipeline from Hugoton gas fields in southwest Kansas to West Virginia to carry 285 million cu. ft. of natural gas per day. The cost was estimated at $51,000,000. Moody's Manual of Public Utilities (1943) 1760.

But there is nothing in the law which compels a commission to fix a price at that 'value' which a company might give to its product by taking advantage of scarcity, or monopoly of supply. The very purpose of fixing maximum prices is to take away from the seller his opportunity to get all that otherwise the market would award him for his goods. This is a constitutional use of the power to fix maximum prices, ****313**Block v. Hirsh, 256 U.S. 135, 41 S.Ct. 458, 65 L.Ed. 865, 16 A.L.R. 165; Marcus Brown Holding Co. v. Feldman, 256 U.S. 170, 41 S.Ct. 465, 65 L.Ed. 877; International Harvester Co. v. Kentucky, 234 U.S. 216, 34 S.Ct. 853, 58 L.Ed. 1284; Highland v. Russell Car & Snow Plow Co., 279 U.S. 253, 49 S.Ct. 314, 73 L.Ed. 688, just as the fixing of minimum prices of goods in interstate commerce is constitutional although it takes away from the buyer the advantage in bargaining which market conditions would give him. United States v. Darby, 312 U.S. 100, 657, 61 S.Ct. 451, 85 L.Ed. 609, 132 A.L.R. 1430; Mulford v. Smith, 307 U.S. 38, 59 S.Ct. 648, 83 L.Ed. 1092; United States v. Rock Royal Co-operative, Inc., 307 U.S. 533, 59 S.Ct. 993, 83 L.Ed. 1446; Sunshine Anthracite Coal Co. v. Adkins, 310 U.S. 381, 60 S.Ct. 907, 84 L.Ed. 1263. The Commission has power to fix ***656** a price that will be both maximum and minimum and it has the incidental right, and I think the duty, to choose the economic consequences it will promote or retard in production and also more importantly in consumption, to which I now turn.

If we assume that the reduction in company revenues is warranted we then come to the question of translating the allowed return into rates for consumers or classes of consumers. Here the Commission fixed a single rate for all gas delivered irrespective of its use despite the fact that Hope has established what amounts to two rates-a high one for domestic use and a lower one for industrial contracts. [FN46] The Commission can fix two prices for interstate gas as readily as one-a price for resale to domestic users and another for resale to industrial users. This is the pattern Hope itself has established in the very contracts over which the Commission is expressly given jurisdiction. Certainly the Act is broad enough to permit two prices to be fixed instead of one, if the concept of the 'public interest' is not unduly narrowed.

FN46 I find little information as to the rates for industries in the record and none at all in such usual sources as Moody's Manual.

The Commission's concept of the public interest in natural

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gas cases which is carried today into the Court's opinion was first announced in the opinion of the minority in the Pipeline case. It enumerated only two 'phases of the public interest: (1) the investor interest; (2) the consumer interest,' which it emphasized to the exclusion of all others. 315 U.S. 575, 606, 62 S.Ct. 736, 753, 86 L.Ed. 1037. This will do well enough in dealing with railroads or utilities supplying manufactured gas, electric, power, a communications service or transportation, where utilization of facilities does not impair their future usefulness. Limitation of supply, however, brings into a natural gas case another phase of the public interest that to my mind overrides both the owner ***657** and the consumer of that interest. Both producers and industrial consumers have served their immediate private interests at the expense of the long-range public interest. The public interest, of course, requires stopping unjust enrichment of the owner. But it also requires stopping unjust impoverishment of future generations. The public interest in the use by Hope's half million domestic consumers is quite a different one from the public interest in use by a baker's dozen of industries.

Prudent price fixing it seems to me must at the very threshold determine whether any part of an allowed return shall be permitted to be realized from sales of gas for resale for industrial use. Such use does tend to level out daily and seasonal peaks of domestic demand and to some extent permits a lower charge for domestic service. But is that a wise way of making gas cheaper when, in comparison with any substitute, gas is already a cheap fuel? The interstate sales contracts provide that at times when demand is so great that there is not enough gas to go around domestic users shall first be served. Should the operation of this preference await the day of actual shortage? Since the propriety of a preference seems conceded, should it not operate to prevent the coming of a shortage as well as to mitigate its effects? Should industrial use jeopardize tomorrow's service to householders any more than today's? If, however, it is decided to cheapen domestic use by resort to industrial sales, should they be limited to the few uses ****314** for which gas has special values or extend also to those who use it only because it is cheaper than competitive fuels? FN47 And how much cheaper should industrial***658** gas sell than domestic gas, and how much advantage should it have over competitive fuels? If industrial gas is to contribute at all to lowering domestic rates, should it not be made to contribute the very maximum of which it is capable, that is, should not its price be the highest at which the desired volume of sales can be realized?

FN47 The Federal Power Commission has touched upon the problem of conservation in connection with an application for a certificate permitting construction of a 1500-mile pipeline from southern Texas to New York City and says: 'The Natural Gas Act as presently drafted does not enable the Commission to treat fully the serious implications of such a problem. The question should be raised as to whether the proposed use of natural gas would not result in displacing a less valuable fuel and create hardships in the industry already supplying the market, while at the same time rapidly depleting the country's natural-gas reserves. Although, for a period of perhaps 20 years, the natural gas could be so priced as to appear to offer an apparent saving in fuel costs, this would mean simply that social costs which must eventually be paid had been ignored.
'Careful study of the entire problem may lead to the conclusion that use of natural gas should be restricted by functions rather than by areas. Thus, it is especially adapted to space and water heating in urban homes and other buildings and to the various industrial heat processes which require concentration of heat, flexibility of control, and uniformity of results. Industrial uses to which it appears particularly adapted include the treating and annealing of metals, the operation of kilns in the ceramic, cement, and lime industries, the manufacture of glass in its various forms, and use as a raw material in the chemical industry. General use of natural gas under boilers for the production of steam is, however, under most circumstances of very questionable social economy.' Twentieth Annual Report of the Federal Power Commission (1940) 79.

If I were to answer I should say that the household rate should be the lowest that can be fixed under commercial conditions that will conserve the supply for that use. The lowest probable rate for that purpose is not likely to speed exhaustion much, for it still will be high enough to induce economy, and use for that purpose has more nearly reached the saturation point. On the other hand the demand for industrial gas at present rates already appears to be increasing. To lower further the industrial rate is merely further to subsidize industrial consumption and speed depletion. The impact of the flat reduction ***659** of rates ordered here admittedly will be to increase the industrial advantages of gas over competing fuels and to increase its use. I think this is not, and there is no finding by the Commission that it is, in the public interest.

There is no justification in this record for the present discrimination against domestic users of gas in favor of industrial users. It is one of the evils against which the Natural Gas Act was aimed by Congress and one of the evils complained of here by Cleveland and Akron. If

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Hope's revenues should be cut by some $3,600,000 the whole reduction is owing to domestic users. If it be considered wise to raise part of Hope's revenues by industrial purpose sales, the utmost possible revenue should be raised from the least consumption of gas. If competitive relationships to other fuels will permit, the industrial price should be substantially advanced, not for the benefit of the Company, but the increased revenues from the advance should be applied to reduce domestic rates. For in my opinion the 'public interest' requires that the great volume of gas now being put to uneconomic industrial use should either be saved for its more important future domestic use or the present domestic user should have the full benefit of its exchange value in reducing his present rates.

Of course the Commission's power directly to regulate does not extend to the fixing of rates at which the local company shall sell to consumers. Nor is such power required to accomplish the purpose. As already pointed out, the very contract the Commission is altering classifies the gas according to the purposes for which it is to be resold and provides differentials between the two classifications. It would only be necessary for the Commission to order ****315** that all gas supplied under paragraph (a) of Hope's contract with the East Ohio Company shall be ***660** at a stated price fixed to give to domestic service the entire reduction herein and any further reductions that may prove possible by increasing industrial rates. It might further provide that gas delivered under paragraph (b) of the contract for industrial purposes to those industrial customers Hope has approved in writing shall be at such other figure as might be found consistent with the public interest as herein defined. It is too late in the day to contend that the authority of a regulatory commission does not extend to a consideration of public interests which it may not directly regulate and a conditioning of its orders for their protection. Interstate Commerce Commission v. Railway Labor Executives Ass'n, 315 U.S. 373, 62 S.Ct. 717, 86 L.Ed. 904; United States v. Lowden, 308 U.S. 225, 60 S.Ct. 248, 84 L.Ed. 208.

Whether the Commission will assert its apparently broad statutory authorization over prices and discriminations is, of course, its own affair, not ours. It is entitled to its own notion of the 'public interest' and its judgment of policy must prevail. However, where there is ground for thinking that views of this Court may have constrained the Commission to accept the rate-base method of decision and a particular single formula as 'all important' for a rate base, it is appropriate to make clear the reasons why I, at least, would not be so understood. The Commission is free to face up realistically to the nature and peculiarity of the resources in its control, to foster their duration in fixing price, and to consider future interests in addition to those of investors and present consumers. If we return this case it may accept or decline the proffered freedom. This problem presents the Commission an unprecedented opportunity if it will boldly make sound economic considerations, instead of legal and accounting theories, the foundation of federal policy. I would return the case to the Commission and thereby be clearly quit of what now may appear to be some responsibility for perpetrating a shortsighted pattern of natural gas regulation.

U.S. 1944.
Federal Power Commission v. Hope Natural Gas Co.
51 P.U.R.(NS) 193, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333

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43 S.Ct. 675
Supreme Court of the United States

BLUEFIELD WATERWORKS
& IMPROVEMENT CO.
v.
PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA et al.

No. 256. | Argued January 22, 1923. | Decided June 11, 1923.

In Error to the Supreme Court of Appeals of West Virginia.

Proceedings by the Bluefield Waterworks & Improvement Company against the Public Service Commission of the State of West Virginia and others to suspend and set aside an order of the Commission fixing rates. From a judgment of the Supreme Court of West Virginia, dismissing the petition, and denying the relief (89 W. Va. 736, 110 S. E. 205), the Waterworks Company bring error. Reversed.

West Headnotes (6)

[1] Constitutional Law
Charges and prices in general

Rates which are not sufficient to yield a reasonable return on the value of the property used in public service at the time it is being so used to render the service are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property, in violation of the Fourteenth Amendment of the Constitution.

109 Cases that cite this headnote

[2] Constitutional Law
Water, sewer, and irrigation

Under the due process clause of the Fourteenth Amendment of the Constitution, U.S.C.A., a waterworks company is entitled to the independent judgment of the court as to both law and facts, where the question is whether the rates fixed by a public service commission are confiscatory.

33 Cases that cite this headnote

[3] Water Law
Methodologies; establishment of rate base

It was error for a state public service commission, in arriving at the value of the property used in public service, for the purpose of fixing the rates, to fail to give proper weight to the greatly increased cost of construction since the war.

25 Cases that cite this headnote

[4] Water Law
Rate of return

A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to such profits as are realized or anticipated in highly profitable enterprises or speculative ventures.

150 Cases that cite this headnote

[5] Water Law
Rate of return

Since the investors take into account the result of past operations as well as present rates in determining whether they will invest, a waterworks company which had been earning a low rate of returns through a long period up to the time of the inquiry is entitled to return of more than 6 per cent. on the value of its property used in the public service, in order to justly compensate it for the use of its property.

154 Cases that cite this headnote

[6] Federal Courts
Particular Cases, Contexts, and Questions

A proceeding in a state court attacking an order of a public service commission fixing rates, on the ground that the rates were confiscatory and the order void under the federal Constitution, is one where there is drawn in question the validity of authority exercised under the state, on the ground of repugnancy to the federal Constitution, and therefore is reviewable by writ of error.

21 Cases that cite this headnote

Attorneys and Law Firms

****675** ***680** Messrs. Alfred G. Fox and Jos. M. Sanders, both of Bluefield, W. Va., for plaintiff in error.

Mr. Russell S. Ritz, of Bluefield, W. Va., for defendants in error.

Opinion

***683** Mr. Justice BUTLER delivered the opinion of the Court.

Plaintiff in error is a corporation furnishing water to the city of Bluefield, W. Va., ****676** and its inhabitants. September 27, 1920, the Public Service Commission of the state, being authorized by statute to fix just and reasonable rates, made its order prescribing rates. In accordance with the laws of the state (section 16, c. 15–O, Code of West Virginia [sec. 651]), the company instituted proceedings in the Supreme Court of Appeals to suspend and set aside the order. The petition alleges that the order is repugnant to the Fourteenth Amendment, and deprives the company of its property without just compensation and without due process of law, and denies it equal protection of the laws. A final judgment was entered, denying the company relief and dismissing its petition. The case is here on writ of error.

[1] 1. The city moves to dismiss the writ of error for the reason, as it asserts, that there was not drawn in question the validity of a statute or an authority exercised under the state, on the ground of repugnancy to the federal Constitution.

The validity of the order prescribing the rates was directly challenged on constitutional grounds, and it was held valid by the highest court of the state. The prescribing of rates is a legislative act. The commission is an instrumentality of the state, exercising delegated powers. Its order is of the same force as would be a like enactment by the Legislature. If, as alleged, the prescribed rates are confiscatory, the order is void. Plaintiff in error is entitled to bring the case here on writ of error and to have that question decided by this court. The motion to dismiss will be denied. See ***684** Oklahoma Natural Gas Co. v. Russell, 261 U. S. 290, 43 Sup. Ct. 353, 67 L. Ed. 659, decided March 5, 1923, and cases cited; also Ohio Valley Co. v. Ben Avon Borough, 253 U. S. 287, 40 Sup. Ct. 527, 64 L. Ed. 908.

2. The commission fixed $460,000 as the amount on which the company is entitled to a return. It found that under existing rates, assuming some increase of business, gross earnings for 1921 would be $80,000 and operating expenses $53,000 leaving $27,000, the equivalent of 5.87 per cent., or 3.87 per cent. after deducting 2 per cent. allowed for depreciation. It held existing rates insufficient to the extent of 10,000. Its order allowed the company to add 16 per cent. to all bills, excepting those for public and private fire protection. The total of the bills so to be increased amounted to $64,000; that is, 80 per cent. of the revenue was authorized to be increased 16 per cent., equal to an increase of 12.8 per cent. on the total, amounting to $10,240.

As to value: The company claims that the value of the property is greatly in excess of $460,000. Reference to the evidence is necessary. There was submitted to the commission evidence of value which it summarized substantially as follows:

a.	Estimate by company's engineer on basis of reproduction new, less depreciation, at prewar prices.....	$ 624,548 00
b.	Estimate by company's engineer on basis of reproduction new, less depreciation, at 1920 prices.....	1,194,663 00

c.	Testimony of company's engineer fixing present fair value for rate making purposes.....	900,000 00
d.	Estimate by commissioner's engineer on basis of reproduction new, less depreciation at 1915 prices, plus additions since December 31, 1915, at actual cost, excluding Bluefield Valley waterworks, water rights, and going value.....	397,964 38
e.	Report of commission's statistician showing investment cost less depreciation.....	365,445 13
f.	Commission's valuation, as fixed in case No. 368 ($360,000), plus gross additions to capital since made ($92,520.53).....	452,520 53

***685** It was shown that the prices prevailing in 1920 were nearly double those in 1915 and pre-war time. The company did not claim value as high as its estimate of cost of construction in 1920. Its valuation engineer testified that in his opinion the value of the property was $900,000—a figure between the cost of construction in 1920, less depreciation, and the cost of construction in 1915 and before the war, less depreciation.

The commission's application of the evidence may be stated briefly as follows:

As to 'a,' supra: The commission deducted $204,000 from the estimate (details printed in the margin), [1] leaving approximately $421,000, which it contrasted with the estimate of its own engineer, $397,964.38 (see 'd,' supra). It found that there should be included $25,000 for the Bluefield Valley waterworks plant in Virginia, 10 per cent. for going value, and $10,000 for working capital. If these be added to $421,000, there results $500,600. This may be compared with the commission's final figure, $460,000.

***686** As to 'b' and 'c,' supra: These were given no weight by the commission in arriving at its final figure, $460,000. It said:

> 'Applicant's plant was originally constructed more than twenty years ago, and has been added to from time to time as the progress and development of the community required. For this reason, it would be unfair to its consumers to use as a basis for present fair value the abnormal prices prevailing during the recent war period; but, when, as in this case, a part of the plant has been constructed or added to during that period, in fairness to the applicant, consideration must be given to

> the cost of such expenditures made to meet the demands of the public.'

****677** As to 'd,' supra: The commission, taking $400,000 (round figures), added $25,000 for Bluefield Valley waterworks plant in Virginia, 10 per cent. for going value, and $10,000 for working capital, making $477,500. This may be compared with its final figure, $460,000.

As to 'e,' supra: The commission, on the report of its statistician, found gross investment to be $500,402.53. Its engineer, applying the straight line method, found 19 per cent. depreciation. It applied 81 per cent. to gross investment and added 10 per cent. for going value and $10,000 for working capital, producing $455,500.[2] This may be compared with its final figure, $460,000.

As to 'f,' supra: It is necessary briefly to explain how this figure, $452,520.53, was arrived at. Case No. 368 was a proceeding initiated by the application of the company for higher rates, April 24, 1915. The commission made a valuation as of January 1, 1915. There were presented two estimates of reproduction cost less depreciation, one by a valuation engineer engaged by the company, ***687** and the other by a valuation engineer engaged by the city, both 'using the same method.' An inventory made by the company's engineer was accepted as correct by the city and by the commission. The method 'was that generally employed by courts and commissions in arriving at the value of public utility properties under this method.' and in both estimates 'five year average unit prices' were applied. The estimate of the company's engineer was $540,000 and of the city's engineer, $392,000. The principal differences as given by the commission are shown in the margin.[3] The commission disregarded both estimates and arrived at $360,000. It held that the best basis of valuation was the net investment, i. e., the total cost of the property less depreciation. It said:
'The books of the company show a total gross investment, since its organization, of $407,882, and that there has been charged off for depreciation from year to year the total sum of $83,445, leaving a net investment of $324,427. * * * From an examination of the books * * * it appears that the records of the company have been remarkably well kept and preserved. It therefore seems that, when a plant is developed under these conditions, the net investment, which, of course, means the total gross investment less depreciation, is the very best basis of valuation for rate making purposes and that the other methods above referred to should ***688** be used only when it is impossible to arrive at the true investment. Therefore, after making due allowance for capital necessary for the conduct of the business and considering the plant as a going concern, it is the opinion of the commission that the fair value for the purpose of determining reasonable and just rates in this case of the property of the applicant company, used by it in the public service of supplying water to the city of Bluefield and its citizens, is the sum of $360,000, which sum is hereby fixed and determined by the commission to be the fair present value for the said purpose of determining the reasonable and just rates in this case.'

In its report in No. 368, the commission did not indicate the amounts respectively allowed for going value or working capital. If 10 per cent. be added for the former, and $10,000 for the latter (as fixed by the commission in the present case), there is produced $366,870, to be compared with $360,000, found by the commission in its valuation as of January 1, 1915. To this it added $92,520.53, expended since, producing $452,520.53. This may be compared with its final figure, $460,000.

The state Supreme Court of Appeals holds that the valuing of the property of a public utility corporation and prescribing rates are purely legislative acts, not subject to judicial review, except in so far as may be necessary to determine whether such rates are void on constitutional or other grounds, and that findings of fact by the commission based on evidence to support them will not be reviewed by the court. City of Bluefield v. Waterworks, 81 W. Va. 201, 204, 94 S. E. 121; Coal & Coke Co. v. Public Service Commission, 84 W. Va. 662, 678, 100 S. E. 557, 7 A. L. R. 108; Charleston v. Public Service Commission, 86 W. Va. 536, 103 S. E. 673.

In this case (89 W. Va. 736, 738, 110 S. E. 205, 206) it said: 'From the written opinion of the commission we find that it ascertained the value of the petitioner's property for rate making [then quoting the commission] 'after ***689** maturely and carefully considering the various methods presented for the ascertainment of fair value and giving such weight as seems proper to every element involved and all the facts and circumstances disclosed by the record.''

[2] [3] The record clearly shows that the commission, in arriving at its final figure, did not accord proper, if any, weight to the greatly enhanced costs of construction in 1920 over those prevailing about 1915 and before the war, as established by uncontradicted ****678** evidence; and the company's detailed estimated cost of reproduction

new, less depreciation, at 1920 prices, appears to have been wholly disregarded. This was erroneous. Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, 262 U. S. 276, 43 Sup. Ct. 544, 67 L. Ed. 981, decided May 21, 1923. Plaintiff in error is entitled under the due process clause of the Fourteenth Amendment to the independent judgment of the court as to both law and facts. Ohio Valley Co. v. Ben Avon Borough, 253 U. S. 287, 289, 40 Sup. Ct. 527, 64 L. Ed. 908, and cases cited.

We quote further from the court's opinion (89 W. Va. 739, 740, 110 S. E. 206):
'In our opinion the commission was justified by the law and by the facts in finding as a basis for rate making the sum of $460,000.00. * * * In our case of Coal & Coke Ry. Co. v. Conley, 67 W. Va. 129, it is said: 'It seems to be generally held that, in the absence of peculiar and extraordinary conditions, such as a more costly plant than the public service of the community requires, or the erection of a plant at an actual, though extravagant, cost, or the purchase of one at an exorbitant or inflated price, the actual amount of money invested is to be taken as the basis, and upon this a return must be allowed equivalent to that which is ordinarily received in the locality in which the business is done, upon capital invested in similar enterprises. In addition to this, consideration must be given to the nature of the investment, a higher rate ***690** being regarded as justified by the risk incident to a hazardous investment.'

'That the original cost considered in connection with the history and growth of the utility and the value of the services rendered constitute the principal elements to be considered in connection with rate making, seems to be supported by nearly all the authorities.'

[4] The question in the case is whether the rates prescribed in the commission's order are confiscatory and therefore beyond legislative power. Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment. This is so well settled by numerous decisions of this court that citation of the cases is scarcely necessary:
'What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience.' Smyth v. Ames (1898) 169 U. S. 467, 547, 18 Sup. Ct. 418, 434 (42 L. Ed. 819).

'There must be a fair return upon the reasonable value of the property at the time it is being used for the public. * * * And we concur with the court below in holding that the value of the property is to be determined as of the time when the inquiry is made regarding the rates. If the property, which legally enters into the consideration of the question of rates, has increased in value since it was acquired, the company is entitled to the benefit of such increase.' Willcox v. Consolidated Gas Co. (1909) 212 U. S. 19, 41, 52, 29 Sup. Ct. 192, 200 (53 L. Ed. 382, 15 Ann. Cas. 1034, 48 L. R. A. [N. S.] 1134).

'The ascertainment of that value is not controlled by artificial rules. It is not a matter of formulas, but there must be a reasonable judgment having its basis in a proper consideration of all relevant facts.' Minnesota Rate Cases (1913) 230 U. S. 352, 434, 33 Sup. Ct. 729, 754 (57 L. Ed. 1511, 48 L. R. A. [N. S.] 1151, Ann. Cas. 1916A, 18).

***691** 'And in order to ascertain that value, the original cost of construction, the amount expended in permanent improvements, the amount and market value of its bonds and stock, the present as compared with the original cost of construction, the probable earning capacity of the property under particular rates prescribed by statute, and the sum required to meet operating expenses, are all matters for consideration, and are to be given such weight as may be just and right in each case. We do not say that there may not be other matters to be regarded in estimating the value of the property.' Smyth v. Ames, 169 U. S., 546, 547, 18 Sup. Ct. 434, 42 L. Ed. 819.

'* * * The making of a just return for the use of the property involves the recognition of its fair value if it be more than its cost. The property is held in private ownership and it is that property, and not the original cost of it, of which the owner may not be deprived without due process of law.'

Minnesota Rate Cases, 230 U. S. 454, 33 Sup. Ct. 762, 57 L. Ed. 1511, 48 L. R. A. (N. S.) 1151, Ann. Cas. 1916A, 18.

In Missouri ex rel. Southwestern Bell Telephone Co., v. Public Service Commission of Missouri, supra, applying the principles of the cases above cited and others, this court said:

> 'Obviously, the commission undertook to value the property without according any weight to the greatly enhanced costs of material, labor, supplies, etc., over those prevailing in 1913, 1914, and

> 1916. As matter of common knowledge, these increases were large. Competent witnesses estimated them as 45 to 50 per centum. * * * It is impossible to ascertain what will amount to a fair return upon properties devoted to public service, without giving consideration to the cost of labor, supplies, etc., at the time the investigation is made. An honest and intelligent forecast of probable future values, made upon a view of all the relevant circumstances, is essential. If the highly important element of present costs is wholly disregarded, such a forecast becomes impossible. Estimates for to-morrow cannot ignore prices of to-day.'

[5] ***692** It is clear that the court also failed to give proper consideration to the higher cost of construction in 1920 over that in 1915 and before the war, and failed to give weight to cost of reproduction less depreciation on the basis of 1920 prices, or to the testimony of the company's valuation engineer, based on present and past costs of construction, that the property in his opinion, was worth $900,000. The final figure, $460,000, was arrived ****679** at substantially on the basis of actual cost, less depreciation, plus 10 per cent. for going value and $10,000 for working capital. This resulted in a valuation considerably and materially less than would have been reached by a fair and just consideration of all the facts. The valuation cannot be sustained. Other objections to the valuation need not be considered.

3. Rate of return: The state commission found that the company's net annual income should be approximately $37,000, in order to enable it to earn 8 per cent. for return and depreciation upon the value of its property as fixed by it. Deducting 2 per cent. for depreciation, there remains 6 per cent. on $460,000, amounting to $27,600 for return. This was approved by the state court.

[6] The company contends that the rate of return is too low and confiscatory. What annual rate will constitute just compensation depeds upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in ***693** highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

In 1909, this court, in Willcox v. Consolidated Gas Co., 212 U. S. 19, 48–50, 29 Sup. Ct. 192, 53 L. Ed. 382, 15 Ann. Cas. 1034, 48 L. R. A. (N. S.) 1134, held that the question whether a rate yields such a return as not to be confiscatory depends upon circumstances, locality and risk, and that no proper rate can be established for all cases; and that, under the circumstances of that case, 6 per cent. was a fair return on the value of the property employed in supplying gas to the city of New York, and that a rate yielding that return was not confiscatory. In that case the investment was held to be safe, returns certain and risk reduced almost to a minimum—as nearly a safe and secure investment as could be imagined in regard to any private manufacturing enterprise.

In 1912, in Cedar Rapids Gas Co. v. Cedar Rapids, 223 U. S. 655, 670, 32 Sup. Ct. 389, 56 L. Ed. 594, this court declined to reverse the state court where the value of the plant considerably exceeded its cost, and the estimated return was over 6 per cent.

In 1915, in Des Moines Gas Co. v. Des Moines, 238 U. S. 153, 172, 35 Sup. Ct. 811, 59 L. Ed. 1244, this court declined to reverse the United States District Court in refusing an injunction upon the conclusion reached that a return of 6 per cent. per annum upon the value would not be confiscatory.

In 1919, this court in Lincoln Gas Co. v. Lincoln, 250 U. S. 256, 268, 39 Sup. Ct. 454, 458 (63 L. Ed. 968), declined on the facts of that case to approve a finding that no rate yielding as much as 6 per cent. ***694** on the invested capital could be regarded as confiscatory. Speaking for the court, Mr. Justice Pitney said:

> 'It is a matter of common knowledge that, owing principally to the World War, the costs of labor and supplies of every

> kind have greatly advanced since the ordinance was adopted, and largely since this cause was last heard in the court below. And it is equally well known that annual returns upon capital and enterprise the world over have materially increased, so that what would have been a proper rate of return for capital invested in gas plants and similar public utilities a few years ago furnishes no safe criterion for the present or for the future.'

In 1921, in Brush Electric Co. v. Galveston, the United States District Court held 8 per cent. a fair rate of return. [4]

In January, 1923, in City of Minneapolis v. Rand, the Circuit Court of Appeals of the Eighth Circuit (285 Fed. 818, 830) sustained, as against the attack of the city on the ground that it was excessive, 7 ½ per cent., found by a special master and approved by the District Court as a fair and reasonable return on the capital investment—the value of the property.

[7] Investors take into account the result of past operations, especially in recent years, when determining the terms upon which they will invest in such an undertaking. Low, uncertain, or irregular income makes for low prices for the securities of the utility and higher rates of interest to be demanded by investors. The fact that the company may not insist as a matter of constitutional right that past losses be made up by rates to be applied in the present and future tends to weaken credit, and the fact that the utility is protected against being compelled to serve for confiscatory rates tends to support it. In ***695** this case the record shows that the rate of return has been low through a long period up to the time of the inquiry by the commission here involved. For example, the average rate of return on the total cost of the property from 1895 to 1915, inclusive, was less than 5 per cent.; from 1911 to 1915, inclusive, ****680** about 4.4 per cent., without allowance for depreciation. In 1919 the net operating income was approximately $24,700, leaving $15,500, approximately, or 3.4 per cent. on $460,000 fixed by the commission, after deducting 2 per cent. for depreciation. In 1920, the net operating income was approximately $25,465, leaving $16,265 for return, after allowing for depreciation. Under the facts and circumstances indicated by the record, we think that a rate of return of 6 per cent. upon the value of the property is substantially too low to constitute just compensation for the use of the property employed to render the service.

The judgment of the Supreme Court of Appeals of West Virginia is reversed.

Mr. Justice BRANDEIS concurs in the judgment of reversal, for the reasons stated by him in Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, supra.

Parallel Citations

P.U.R. 1923D 11, 43 S.Ct. 675, 67 L.Ed. 1176

Footnotes

1

Difference in depreciation allowed	$ 49,000
Preliminary organization and development cost	14,500
Bluefield Valley waterworks plant	25,000
Water rights	50,000
Excess overhead costs	39,000
Paving over mains	28,500
	$204,000

2 As to 'e': $365,445.13 represents investment cost less depreciation. The gross investment was found to be $500,402.53, indicating a deduction on account of depreciation of $134,957.40, about 27 per cent., as against 19 per cent. found by the commission's engineer.

3

		Company Engineer.	City Engineer.
1.	Preliminary costs	$14,455	$1,000
2.	Water rights	50,000	Nothing
3.	Cutting pavements over		

	mains	27,744	233
4.	Pipe lines from gravity springs	22,072	15,442
5.	Laying cast iron street mains	19,252	15,212
6.	Reproducing Ada springs	18,558	13,027
7.	Superintendence and engineering	20,515	13,621
8.	General contingent cost	16,415	5,448
		$189,011	$63,983

4 This case was affirmed by this court June 4, 1923, 262 U. S. 443, 43 Sup. Ct. 606, 67 L. Ed. 1076.

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ALLETE INC

FORM 10-K
(Annual Report)

Filed 02/15/18 for the Period Ending 12/31/17

Address	30 W SUPERIOR ST
	DULUTH, MN, 55802-2093
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CIK	0000066756
Symbol	ALE
SIC Code	4931 - Electric and Other Services Combined
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

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United States
Securities and Exchange Commission
Washington, D.C. 20549

Form 10-K

(Mark One)

T Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2017**

£ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from _____ to _____

Commission File Number **1-3548**

ALLETE, Inc.

(Exact name of registrant as specified in its charter)

Minnesota	**41-0418150**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

30 West Superior Street, Duluth, Minnesota 55802-2093
(Address of principal executive offices, including zip code)

(218) 279-5000
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, without par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ☒	Accelerated Filer ☐	Non-Accelerated Filer ☐
	Smaller Reporting Company ☐	Emerging Growth Company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of voting stock held by nonaffiliates on June 30, 2017 , was $3,637,956,646 .

As of February 1, 2018 , there were 51,143,656 shares of ALLETE Common Stock, without par value, outstanding.

Documents Incorporated By Reference

Portions of the Proxy Statement for the 2018 Annual Meeting of Shareholders are incorporated by reference in Part III.

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Definitions

The following abbreviations or acronyms are used in the text. References in this report to "we," "us" and "our" are to ALLETE, Inc. and its subsidiaries, collectively.

Abbreviation or Acronym	Term
AFUDC	Allowance for Funds Used During Construction - the cost of both debt and equity funds used to finance utility plant additions during construction periods
ALLETE	ALLETE, Inc.
ALLETE Clean Energy	ALLETE Clean Energy, Inc. and its subsidiaries
ALLETE Properties	ALLETE Properties, LLC and its subsidiaries
ALLETE Transmission Holdings	ALLETE Transmission Holdings, Inc.
ArcelorMittal	ArcelorMittal USA, Inc.
ASC	Accounting Standards Codification
ATC	American Transmission Company LLC
Basin	Basin Electric Power Cooperative
Bison	Bison Wind Energy Center
BNI Energy	BNI Energy, Inc. and its subsidiary
Boswell	Boswell Energy Center
Camp Ripley	Camp Ripley Solar Array
CIP	Conservation Improvement Program
Cliffs	Cleveland-Cliffs Inc.
CO_2	Carbon Dioxide
Company	ALLETE, Inc. and its subsidiaries
DC	Direct Current
EIS	Environmental Impact Statement
EITE	Energy-Intensive Trade-Exposed
EPA	United States Environmental Protection Agency
ERP Iron Ore	ERP Iron Ore, LLC
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Form 8-K	ALLETE Current Report on Form 8-K
Form 10-K	ALLETE Annual Report on Form 10-K
Form 10-Q	ALLETE Quarterly Report on Form 10-Q
GAAP	Generally Accepted Accounting Principles in the United States of America
GHG	Greenhouse Gases
GNTL	Great Northern Transmission Line
Invest Direct	ALLETE's Direct Stock Purchase and Dividend Reinvestment Plan
IRP	Integrated Resource Plan
Item ___	Item ___ of this Form 10-K
kV	Kilovolt(s)
kW / kWh	Kilowatt(s) / Kilowatt-hour(s)
Laskin	Laskin Energy Center
LIBOR	London Interbank Offered Rate
Magnetation	Magnetation, LLC
Manitoba Hydro	Manitoba Hydro-Electric Board
MBtu	Million British thermal units

Abbreviation or Acronym	Term
Mesabi Metallics	Mesabi Metallics Company, LLC
Minnesota Power	An operating division of ALLETE, Inc.
Minnkota Power	Minnkota Power Cooperative, Inc.
MISO	Midcontinent Independent System Operator, Inc.
Montana-Dakota Utilities	Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc.
Moody's	Moody's Investors Service, Inc.
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatt-hour(s)
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NOL	Net Operating Loss
NO_2	Nitrogen Dioxide
NO_X	Nitrogen Oxides
Northern States Power	Northern States Power Company, a subsidiary of Xcel Energy Inc.
Northshore Mining	Northshore Mining Company, a wholly-owned subsidiary of Cliffs
Note ___	Note ___ to the consolidated financial statements in this Form 10-K
NYSE	New York Stock Exchange
Oliver Wind I	Oliver Wind I Energy Center
Oliver Wind II	Oliver Wind II Energy Center
Palm Coast Park District	Palm Coast Park Community Development District in Florida
PolyMet	PolyMet Mining Corp.
PPA / PSA	Power Purchase Agreement / Power Sales Agreement
PPACA	Patient Protection and Affordable Care Act of 2010
PSCW	Public Service Commission of Wisconsin
RSOP	Retirement Savings and Stock Ownership Plan
SEC	Securities and Exchange Commission
Shell Energy	Shell Energy North America (US), L.P.
Silver Bay Power	Silver Bay Power Company, a wholly-owned subsidiary of Cliffs
SO_2	Sulfur Dioxide
Square Butte	Square Butte Electric Cooperative, a North Dakota cooperative corporation
Standard & Poor's	S&P Global Ratings
SWL&P	Superior Water, Light and Power Company
Taconite Harbor	Taconite Harbor Energy Center
Taconite Ridge	Taconite Ridge Energy Center
Tenaska	Tenaska Energy, Inc. and Tenaska Energy Holdings, LLC
Thomson	Thomson Energy Center
TCJA	Tax Cuts and Jobs Act of 2017 (Public Law 115-97)
Tonka Water	Tonka Equipment Company
Town Center District	Town Center at Palm Coast Community Development District in Florida
TransAlta	TransAlta Energy Marketing (U.S.) Inc.
United Taconite	United Taconite LLC, a wholly-owned subsidiary of Cliffs
UPM Blandin	UPM, Blandin paper mill owned by UPM-Kymmene Corporation
U.S.	United States of America
U.S. Water Services	U.S. Water Services Holding Company and its subsidiaries
USS Corporation	United States Steel Corporation
WTG	Wind Turbine Generator

Forward-Looking Statements

Statements in this report that are not statements of historical facts are considered "forward-looking" and, accordingly, involve risks and uncertainties that could cause actual results to differ materially from those discussed. Although such forward-looking statements have been made in good faith and are based on reasonable assumptions, there can be no assurance that the expected results will be achieved. Any statements that express, or involve discussions as to, future expectations, risks, beliefs, plans, objectives, assumptions, events, uncertainties, financial performance, or growth strategies (often, but not always, through the use of words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "projects," "likely," "will continue," "could," "may," "potential," "target," "outlook" or words of similar meaning) are not statements of historical facts and may be forward-looking.

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, we are providing this cautionary statement to identify important factors that could cause our actual results to differ materially from those indicated in forward-looking statements made by or on behalf of ALLETE in this Form 10-K, in presentations, on our website, in response to questions or otherwise. These statements are qualified in their entirety by reference to, and are accompanied by, the following important factors, in addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements that could cause our actual results to differ materially from those indicated in the forward-looking statements:

- our ability to successfully implement our strategic objectives;
- global and domestic economic conditions affecting us or our customers;
- changes in and compliance with laws and regulations;
- changes in tax rates or policies or in rates of inflation;
- the outcome of legal and administrative proceedings (whether civil or criminal) and settlements;
- weather conditions, natural disasters and pandemic diseases;
- our ability to access capital markets and bank financing;
- changes in interest rates and the performance of the financial markets;
- project delays or changes in project costs;
- changes in operating expenses and capital expenditures and our ability to raise revenues from our customers in regulated rates or sales price increases at our Energy Infrastructure and Related Services businesses;
- the impacts of commodity prices on ALLETE and our customers;
- our ability to attract and retain qualified, skilled and experienced personnel;
- effects of emerging technology;
- war, acts of terrorism and cyberattacks;
- our ability to manage expansion and integrate acquisitions;
- population growth rates and demographic patterns;
- wholesale power market conditions;
- federal and state regulatory and legislative actions that impact regulated utility economics, including our allowed rates of return, capital structure, ability to secure financing, industry and rate structure, acquisition and disposal of assets and facilities, operation and construction of plant facilities and utility infrastructure, recovery of purchased power, capital investments and other expenses, including present or prospective environmental matters;
- effects of competition, including competition for retail and wholesale customers;
- effects of restructuring initiatives in the electric industry;
- the impacts on our Regulated Operations segment of climate change and future regulation to restrict the emissions of GHG;
- effects of increased deployment of distributed low-carbon electricity generation resources;
- the impacts of laws and regulations related to renewable and distributed generation;
- pricing, availability and transportation of fuel and other commodities and the ability to recover the costs of such commodities;
- our current and potential industrial and municipal customers' ability to execute announced expansion plans;
- real estate market conditions where our legacy Florida real estate investment is located may not improve;
- the success of efforts to realize value from, invest in, and develop new opportunities in, our Energy Infrastructure and Related Services businesses; and
- factors affecting our Energy Infrastructure and Related Services businesses, including fluctuations in the volume of customer orders, unanticipated cost increases, changes in legislation and regulations impacting the industries in which the customers served operate, the effects of weather, creditworthiness of customers, ability to obtain materials required to perform services, and changing market conditions.

Additional disclosures regarding factors that could cause our results or performance to differ from those anticipated by this report are discussed in Part 1, Item 1A under the heading “Risk Factors” of this Form 10-K. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which that statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of these factors, nor can it assess the impact of each of these factors on the businesses of ALLETE or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. Readers are urged to carefully review and consider the various disclosures made by ALLETE in this Form 10-K and in other reports filed with the SEC that attempt to identify the risks and uncertainties that may affect ALLETE’s business.

Part I

Item 1. Business

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in portions of Wisconsin, Michigan, Minnesota and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 145,000 retail customers. Minnesota Power also has 16 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a wholesale customer of Minnesota Power. SWL&P provides regulated utility electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 13,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities . (See Note 4. Regulatory Matters.)

ALLETE Clean Energy focuses on developing, acquiring, and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates, in four states, approximately 535 MW of nameplate capacity wind energy generation that is contracted under PSAs of various durations. ALLETE Clean Energy also engages in the development of wind energy facilities to operate under long-term PSAs or for sale to others upon completion.

U.S. Water Services provides integrated water management for industry by combining chemical, equipment, engineering and service for customized solutions to reduce water and energy usage, and improve efficiency.

Corporate and Other is comprised of BNI Energy, our coal mining operations in North Dakota, ALLETE Properties, our legacy Florida real estate investment, other business development and corporate expenditures, unallocated interest expense, a small amount of non-rate base generation, approximately 5,000 acres of land in Minnesota, and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2017 , unless otherwise indicated. All subsidiaries are wholly-owned unless otherwise specifically indicated. References in this report to “we,” “us” and “our” are to ALLETE and its subsidiaries, collectively.

Year Ended December 31	2017	2016	2015 *(a)*
Consolidated Operating Revenue – Millions	$1,419.3	$1,339.7	$1,486.4
Percentage of Consolidated Operating Revenue			
Regulated Operations	75%	75%	67%
ALLETE Clean Energy	6%	6%	18%
U.S. Water Services	11%	10%	8%
Corporate and Other	8%	9%	7%
	100%	100%	100%

(a) Includes the construction and sale of a wind energy facility by ALLETE Clean Energy to Montana-Dakota Utilities for $197.7 million in 2015.

For a detailed discussion of results of operations and trends, see Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations. For business segment information, see Note 1. Operations and Significant Accounting Policies, and Note 17. Business Segments.

REGULATED OPERATIONS

Electric Sales / Customers

Regulated Utility Kilowatt-hours Sold

Year Ended December 31	2017	%	2016	%	2015	%
Millions						
Retail and Municipal						
Residential	1,096	7	1,102	8	1,113	8
Commercial	1,420	10	1,442	10	1,462	10
Industrial	7,327	50	6,456	45	6,635	46
Municipal	799	5	816	6	833	6
Total Retail and Municipal	10,642	72	9,816	69	10,043	70
Other Power Suppliers	4,039	28	4,316	31	4,310	30
Total Regulated Utility Kilowatt-hours Sold	14,681	100	14,132	100	14,353	100

Industrial Customers . In 2017 , industrial customers represented 50 percent of total regulated utility kWh sales. Our industrial customers are primarily in the taconite mining, iron concentrate, paper, pulp and secondary wood products, and pipeline industries.

Industrial Customer Kilowatt-hours Sold

Year Ended December 31	2017	%	2016	%	2015	%
Millions						
Taconite/Iron Concentrate	4,930	67	3,906	61	4,000	60
Paper, Pulp and Secondary Wood Products	1,104	15	1,303	20	1,456	22
Pipelines and Other Industrial	1,293	18	1,247	19	1,179	18
Total Industrial Customer Kilowatt-hours Sold	7,327	100	6,456	100	6,635	100

Six taconite facilities served by Minnesota Power made up approximately 70 percent of 2016 iron ore pellet production in the U.S. according to data from the Minnesota Department of Revenue 2017 Mining Tax Guide. Sales to taconite customers and iron concentrate customers represented 4,930 million kWh, or 67 percent , of total industrial customer kWh sales in 2017 . Taconite, an iron-bearing rock of relatively low iron content, is abundantly available in northern Minnesota and an important domestic source of raw material for the steel industry. Taconite processing plants use large quantities of electric power to grind the iron-bearing rock, and agglomerate and pelletize the iron particles into taconite pellets. Iron concentrate reclamation facilities also use large quantities of electricity to extract and process iron-bearing tailings left from previous mining operations to produce iron ore concentrate.

Minnesota Power's taconite customers are capable of producing up to approximately 41 million tons of taconite pellets annually. Taconite pellets produced in Minnesota are primarily shipped to North American steel making facilities that are part of the integrated steel industry. Steel produced from these North American facilities is used primarily in the manufacture of automobiles, appliances, pipe and tube products for the gas and oil industry, and in the construction industry. Historically, less than five percent of Minnesota taconite production has been exported outside of North America. Minnesota Power also provides electric service to three iron concentrate facilities capable of producing up to approximately 4 million tons of iron concentrate per year. Iron concentrate is used in the production of taconite pellets. These iron concentrate facilities are owned in whole, or in part, by ERP Iron Ore and are currently idled. (See Item 7. Management's Discussion and Analysis – Outlook – Industrial Customers and Prospective Additional Load.)

There has been a general historical correlation between U.S. steel production and Minnesota taconite production. The American Iron and Steel Institute, an association of North American steel producers, reported that U.S. raw steel production operated at approximately 74 percent of capacity in 2017 (71 percent in 2016 and in 2015). The World Steel Association, an association of over 160 steel producers, national and regional steel industry associations, and steel research institutes representing approximately 85 percent of world steel production, projected U.S. steel consumption in 2018 will increase by approximately 1 percent compared to 2017 .

REGULATED OPERATIONS (Continued)
Industrial Customers (Continued)

The following table reflects Minnesota Power's taconite customers' production levels for the past ten years:

Minnesota Power Taconite Customer Production	
Year	**Tons (Millions)**
2017 *	37
2016	28
2015	31
2014	39
2013	37
2012	39
2011	39
2010	35
2009	17
2008	39
Source: Minnesota Department of Revenue 2017 Mining Tax Guide for years 2008 - 2016.	
** Preliminary data from the Minnesota Department of Revenue.*	

Minnesota Power's taconite customers may experience annual variations in production levels due to such factors as economic conditions, short-term demand changes or maintenance outages. We estimate that a one million ton change in Minnesota Power's taconite customers' production would impact our annual earnings per share by approximately $0.04 , net of expected power marketing sales at current prices. Changes in wholesale electric prices or customer contractual demand nominations could impact this estimate. Minnesota Power proactively sells power in the wholesale power markets that is temporarily not required by industrial customers to optimize the value of its generating facilities. Long-term reductions in taconite production or a permanent shut down of a taconite customer may lead Minnesota Power to file a general rate case to recover lost revenue.

In addition to serving the taconite industry, Minnesota Power serves a number of customers in the paper, pulp and secondary wood products industry, which represented 1,104 million kWh, or 15 percent , of total industrial customer kWh sales in 2017 . Minnesota Power also has agreements to provide steam for two of its paper and pulp customers for use in the customers' operations. The four major paper and pulp mills we serve reported operating at, or near, full capacity in 2017 ; however, the smaller of UPM Blandin's two paper machines was closed in the fourth quarter of 2017. (See Item 7. Management's Discussion and Analysis – Outlook – Industrial Customers and Prospective Additional Load.)

Large Power Customer Contracts. Minnesota Power has nine Large Power Customer contracts, each serving requirements of 10 MW or more of customer load. The customers consist of six taconite facilities, two iron concentrate reclamation facilities and four paper and pulp mills. Certain facilities have common ownership and are served under combined contracts.

Large Power Customer contracts require Minnesota Power to have a certain amount of generating capacity available. In turn, each Large Power Customer is required to pay a minimum monthly demand charge that covers the fixed costs associated with having this capacity available to serve the customer, including a return on common equity. Most contracts allow customers to establish the level of megawatts subject to a demand charge on a four-month basis and require that a portion of their megawatt needs be committed on a take-or-pay basis for at least a portion of the term of the agreement. In addition to the demand charge, each Large Power Customer is billed an energy charge for each kWh used that recovers the variable costs incurred in generating electricity. Five of the Large Power Customer contracts have interruptible service which provides a discounted demand rate in exchange for the ability to interrupt the customers during system emergencies. Minnesota Power also provides incremental production service for customer demand levels above the contractual take-or-pay levels. There is no demand charge for this service and energy is priced at an increment above Minnesota Power's cost. Incremental production service is interruptible.

REGULATED OPERATIONS (Continued)
Large Power Customer Contracts (Continued)

All contracts with Large Power Customers continue past the contract termination date unless the required advance notice of cancellation has been given. The required advance notice of cancellation varies from two to four years. Such contracts minimize the impact on earnings that otherwise would result from significant reductions in kWh sales to such customers. Large Power Customers are required to take all of their purchased electric service requirements from Minnesota Power for the duration of their contracts. The rates and corresponding revenue associated with capacity and energy provided under these contracts are subject to change through the same regulatory process governing all retail electric rates. (See Item 1. Business – Regulated Operations – Regulatory Matters – Electric Rates.)

Minnesota Power, as permitted by the MPUC, requires its taconite-producing Large Power Customers to pay weekly for electric usage based on monthly energy usage estimates. These customers receive estimated bills based on Minnesota Power's estimate of the customer's energy usage, forecasted energy prices and fuel adjustment clause estimates. Minnesota Power's taconite-producing Large Power Customers have generally predictable energy usage on a week-to-week basis and any differences that occur are trued-up the following month.

Contract Status for Minnesota Power Large Power Customers
As of February 1, 2018

Customer	Industry	Location	Ownership	Earliest Termination Date
ArcelorMittal – Minorca Mine	Taconite	Virginia, MN	ArcelorMittal S.A.	December 31, 2025
Hibbing Taconite Co. *(a)*	Taconite	Hibbing, MN	62.3% ArcelorMittal S.A. 23.0% Cliffs 14.7% USS Corporation	February 28, 2022
United Taconite and Northshore Mining	Taconite	Eveleth, MN and Babbitt, MN	Cliffs	December 31, 2026
USS Corporation (USS – Minnesota Ore) *(a)(b)*	Taconite	Mt. Iron, MN and Keewatin, MN	USS Corporation	February 28, 2022
Magnetation *(c)*	Iron Concentrate	Coleraine, MN and Bovey, MN	ERP Iron Ore	December 31, 2025
Boise, Inc.	Paper	International Falls, MN	Packaging Corporation of America	December 31, 2023
UPM Blandin *(a)(d)*	Paper	Grand Rapids, MN	UPM-Kymmene Corporation	February 28, 2022
NewPage Corporation	Paper and Pulp	Duluth, MN	Verso Corporation	December 31, 2022
Sappi Cloquet LLC *(a)*	Paper and Pulp	Cloquet, MN	Sappi Limited	February 28, 2022

(a) The contract will terminate four years from the date of written notice from either Minnesota Power or the customer. No notice of contract cancellation has been given by either party. Thus, the earliest date of cancellation is February 28, 2022.
(b) USS Corporation owns both the Minntac Plant in Mountain Iron, MN, and the Keewatin Taconite Plant in Keewatin, MN.
(c) On January 30, 2017, ERP Iron Ore, LLC purchased substantially all of Magnetation's assets pursuant to an asset purchase agreement approved by the U.S. Bankruptcy Court for the District of Minnesota. (See Item 7. Management's Discussion and Analysis – Outlook – Industrial Customers and Prospective Additional Load.)
(d) The smaller of UPM Blandin's two paper machines was closed in the fourth quarter of 2017. (See Item 7. Management's Discussion and Analysis – Outlook – Industrial Customers and Prospective Additional Load.)

Residential and Commercial Customers. In 2017 , residential and commercial customers represented 17 percent of total regulated utility kWh sales.

Municipal Customers. In 2017 , municipal customers represented 5 percent of total regulated utility kWh sales. All of the municipal contracts include a termination clause requiring a three -year notice to terminate.

REGULATED OPERATIONS (Continued)
Municipal Customers (Continued)

Minnesota Power's wholesale electric contract with the Nashwauk Public Utilities Commission is effective through at least December 31, 2032. No termination notice may be given for this contract prior to July 1, 2029. The wholesale electric service contracts with SWL&P and another municipal customer are effective through at least February 28, 2021, and through June 30, 2019, respectively. Under the agreement with SWL&P, no termination notice has been given. The other municipal customer provided a contract termination notice in June 2016. Minnesota Power currently provides approximately 29 MW of average monthly demand to this customer. The rates included in these three contracts are set each July 1 based on a cost-based formula methodology, using estimated costs and a rate of return that is equal to Minnesota Power's authorized rate of return for Minnesota retail customers. The formula-based rate methodology also provides for a yearly true-up calculation for actual costs incurred.

Minnesota Power's wholesale electric contracts with 14 municipal customers are effective through at least December 31, 2024. No termination notices may be given prior to three years before maturity. These contracts include fixed capacity charges through 2018; beginning in 2019, the capacity charge will be determined using a cost-based formula methodology with limits on the annual change from the previous year's capacity charge. The base energy charge for each year of the contract term will be set each January 1, subject to monthly adjustment, and will also be determined using a cost-based formula methodology.

Other Power Suppliers. The Company also enters into off-system sales with Other Power Suppliers. These sales are at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

Basin PSA. Minnesota Power has an agreement to sell 100 MW of capacity and energy to Basin for a ten-year period which expires in April 2020. The capacity charge is based on a fixed monthly schedule with a minimum annual escalation provision. The energy charge is based on a fixed monthly schedule and provides for annual escalation based on the cost of fuel. The agreement also allows Minnesota Power to recover a pro rata share of increased costs related to emissions that occur during the last five years of the contract. Minnesota Power has an additional agreement to sell 100 MW of capacity to Basin at fixed rates for a two-year period that began in June 2016.

Minnkota Power PSA. Minnesota Power has a PSA with Minnkota Power where Minnesota Power is selling a portion of its entitlement from Square Butte to Minnkota Power, resulting in Minnkota Power's net entitlement increasing and Minnesota Power's net entitlement decreasing until Minnesota Power's share is eliminated at the end of 2025 . Of Minnesota Power's 50 percent output entitlement, it sold approximately 28 percent to Minnkota Power in 2017 (28 percent in 2016 and in 2015). (See Note 11. Commitments, Guarantees and Contingencies.)

Silver Bay Power PSA . In 2016, Minnesota Power and Silver Bay Power entered into a long-term PSA through 2031. Silver Bay Power supplies approximately 90 MW of load to Northshore Mining, an affiliate of Silver Bay Power, which has been served predominately through self-generation by Silver Bay Power. In the years 2016 through 2019, Minnesota Power is supplying Silver Bay Power with at least 50 MW of energy and Silver Bay Power has the option to purchase additional energy from Minnesota Power as it transitions away from self-generation. On December 31, 2019, Silver Bay Power will cease self-generation and Minnesota Power will supply the energy requirements for Silver Bay Power.

Seasonality

The operations of our industrial customers, which make up a large portion of our electric sales, are not typically subject to significant seasonal variations. (See *Electric Sales / Customers.*) As a result, Minnesota Power is generally not subject to significant seasonal fluctuations in electric sales; however, Minnesota Power and SWL&P electric and natural gas sales to other customers may be affected by seasonal differences in weather. In general, peak electric sales occur in the winter and summer months with fewer electric sales in the spring and fall months. Peak sales of natural gas generally occur in the winter months. Additionally, our regulated utilities have historically generated fewer sales and less revenue when weather conditions are milder in the winter and summer.

Power Supply

In order to meet its customers' electric requirements, Minnesota Power utilizes a mix of its own generation and purchased power. As of December 31, 2017 , Minnesota Power's generating capability is primarily coal-fired, but also includes natural gas-fired and biomass co-fired generation, hydroelectric generation, wind energy generation and solar generation. In 2017, Minnesota Power had record hydroelectric and wind energy generation. Purchased power primarily consists of long-term coal, wind and hydro PPAs as well as market purchases. The following table reflects Minnesota Power's generating capabilities as of December 31, 2017 , and total electrical supply for 2017 . Minnesota Power had an annual net peak load of 1,599 MW on December 27, 2017 .

REGULATED OPERATIONS (Continued)
Power Supply (Continued)

Regulated Utility Power Supply	Unit No.	Year Installed	Net Capability		Year Ended December 31, 2017 Generation and Purchases	
			MW		MWh	%
Coal-Fired						
Boswell Energy Center	1	1958	67	*(a)*		
in Cohasset, MN	2	1960	68	*(a)*		
	3	1973	355			
	4	1980	468	*(b)*		
			958		6,286,858	41.4
Taconite Harbor Energy Center	1	1957	75			
in Schroeder, MN	2	1957	75			
			150	*(c)*	—	—
Total Coal-Fired			1,108		6,286,858	41.4
Biomass Co-Fired / Natural Gas						
Hibbard Renewable Energy Center in Duluth, MN	3 & 4	1949, 1951	62		4,502	—
Laskin Energy Center in Hoyt Lakes, MN	1 & 2	1953	110		5,615	0.1
Total Biomass Co-Fired / Natural Gas			172		10,117	0.1
Hydro *(d)*						
Group consisting of ten stations in MN	Multiple	Multiple	120		773,707	5.1
Wind *(e)*						
Taconite Ridge Energy Center in Mt. Iron, MN	Multiple	2008	25		56,594	0.4
Bison Wind Energy Center in Oliver and Morton Counties, ND	Multiple	2010-2014	497		1,775,474	11.7
Total Wind			522		1,832,068	12.1
Solar						
Camp Ripley Solar Array near Little Falls, MN	Multiple	2016	10		17,129	0.1
Total Generation			1,932		8,919,879	58.8
Long-Term Purchased Power						
Lignite Coal - Square Butte near Center, ND *(f)*					1,739,781	11.5
Wind - Oliver County, ND					341,785	2.2
Hydro - Manitoba Hydro in Manitoba, Canada					305,532	2.0
Total Long-Term Purchased Power					2,387,098	15.7
Other Purchased Power *(g)*					3,867,865	25.5
Total Purchased Power					6,254,963	41.2
Total Regulated Utility Power Supply			1,932		15,174,842	100.0

(a) In 2016, Minnesota Power announced that Boswell Units 1 and 2 will be retired in 2018. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook – EnergyForward.)

(b) Boswell Unit 4 net capability shown above reflects Minnesota Power's ownership percentage of 80 percent. WPPI Energy owns 20 percent of Boswell Unit 4. (See Note 3. Jointly-Owned Facilities and Projects.)

(c) Taconite Harbor Units 1 and 2 were idled in 2016. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook – EnergyForward.)

(d) Hydro consists of 10 stations with 34 generating units.

(e) Taconite Ridge consists of 10 WTGs and Bison consists of 165 WTGs.

(f) Minnesota Power has a PSA with Minnkota Power whereby Minnesota Power is selling a portion of its entitlement from Square Butte to Minnkota Power. (See Electric Sales / Customers.)

(g) Includes short-term market purchases in the MISO market and from Other Power Suppliers.

REGULATED OPERATIONS (Continued)
Power Supply (Continued)

Fuel . Minnesota Power purchases low-sulfur, sub-bituminous coal from the Powder River Basin region located in Montana and Wyoming. Coal consumption in 2017 for electric generation at Minnesota Power's coal-fired generating stations was 3.8 million tons (4.2 million tons in 2016 ; 4.4 million tons in 2015). As of December 31, 2017 , Minnesota Power had coal inventories of 1.2 million tons (1.4 million tons as of December 31, 2016). Minnesota Power has coal supply agreements providing for the purchase of a significant portion of its coal requirements through December 2018 and a portion of its coal requirements through December 2021. In 2018 , Minnesota Power expects to obtain coal under these coal supply agreements and in the spot market. Minnesota Power continues to explore other future coal supply options and believes that adequate supplies of low-sulfur, sub-bituminous coal will continue to be available.

Minnesota Power also has coal transportation agreements in place for the delivery of a significant portion of its coal requirements through December 2018. The costs of fuel and related transportation costs for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

Coal Delivered to Minnesota Power

Year Ended December 31	2017	2016	2015
Average Price per Ton	$36.50	$35.87	$27.00
Average Price per MBtu	$2.01	$1.98	$1.49

Long-Term Purchased Power . Minnesota Power has contracts to purchase capacity and energy from various entities, including output from certain coal, wind, hydro and solar generating facilities.

Our PPAs are detailed in Note 11. Commitments, Guarantees and Contingencies, with additional disclosure provided in the following paragraph.

Square Butte PPA. Under the PPA with Square Butte that extends through 2026, Minnesota Power is entitled to 50 percent of the output of Square Butte's 455 MW coal-fired generating unit. (See Note 11. Commitments, Guarantees and Contingencies.) BNI Energy mines and sells lignite coal to Square Butte. This lignite supply is sufficient to provide fuel for the anticipated useful life of the generating unit. Square Butte's cost of lignite consumed in 2017 was approximately $1.71 per MBtu ($1.57 per MBtu in 2016 ; $1.55 per MBtu in 2015). (See *Electric Sales / Customers – Minnkota Power PSA* .)

Transmission and Distribution

We have electric transmission and distribution lines of 500 kV (8 miles), 345 kV (242 miles), 250 kV (466 miles), 230 kV (717 miles), 161 kV (43 miles), 138 kV (190 miles), 115 kV (1,280 miles) and less than 115 kV (6,334 miles). We own and operate 167 substations with a total capacity of 8,540 megavoltamperes. Some of our transmission and distribution lines interconnect with other utilities.

CapX2020. Minnesota Power was a participant in the CapX2020 initiative which represented an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX2020, which consisted of electric cooperatives and municipal and investor-owned utilities, including Minnesota's largest transmission owners, assessed the transmission system and projected growth in customer demand for electricity through 2020. Minnesota Power participated in three CapX2020 projects which were completed and placed in service in 2011, 2012 and 2015.

Great Northern Transmission Line. As a condition of the 250 MW long-term PPA entered into with Manitoba Hydro, construction of additional transmission capacity is required. As a result, Minnesota Power and Manitoba Hydro proposed construction of the GNTL, an approximately 220 -mile 500 -kV transmission line between Manitoba and Minnesota's Iron Range in order to strengthen the electric grid, enhance regional reliability and promote a greater exchange of sustainable energy.

REGULATED OPERATIONS (Continued)
Transmission and Distribution (Continued)

In 2015, a certificate of need was approved by the MPUC. Based on this approval, Minnesota Power's portion of the investments and expenditures for the project are eligible for cost recovery under its existing transmission cost recovery rider and are anticipated to be included in future transmission cost recovery filings. (See Note 4. Regulatory Matters.) Also in 2015, the FERC approved our request to recover on construction work in progress related to the GNTL from Minnesota Power's wholesale customers. In an April 2016 order, the MPUC approved the route permit for the GNTL which largely follows Minnesota Power's preferred route, including the international border crossing, and in November 2016, the U.S. Department of Energy issued a presidential permit to cross the U.S.-Canadian border, which was the final major regulatory approval needed before construction in the U.S. could begin. Site clearing and pre-construction activities commenced in the first quarter of 2017 with construction expected to be completed in 2020. Total project cost in the U.S., including substation work, is estimated to be between $560 million and $710 million , of which Minnesota Power's portion is expected to be between $300 million and $350 million ; the difference will be recovered from a subsidiary of Manitoba Hydro as contributions in aid of construction. Total project costs of $152.4 million have been incurred through December 31, 2017 , of which $67.6 million has been recovered from a subsidiary of Manitoba Hydro.

Manitoba Hydro must obtain regulatory and governmental approvals related to a new transmission line in Canada. In 2015, Manitoba Hydro submitted the final preferred route and EIS for the transmission line in Canada to the Manitoba Conservation and Water Stewardship for regulatory approval. In December 2016, Manitoba Hydro filed an application with the National Energy Board in Canada requesting authorization to construct and operate an international transmission line. Both provincial and federal approvals are pending. Construction of Manitoba Hydro's hydroelectric generation facility commenced in 2014 and is anticipated to be in service by early 2021.

Investment in ATC

Our wholly-owned subsidiary, ALLETE Transmission Holdings, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in portions of Wisconsin, Michigan, Minnesota and Illinois. We account for our investment in ATC under the equity method of accounting. As of December 31, 2017 , our equity investment in ATC was $118.7 million ($135.6 million as of December 31, 2016). The decrease in our equity investment in ATC in 2017 is due to the impact of the remeasurement of deferred income tax assets and liabilities resulting from the TCJA. (See Note 1. Operations and Significant Accounting Policies, and Note 5. Investment in ATC.)

In September 2016, the FERC issued an order reducing ATC's authorized return on equity to 10.32 percent , or 10.82 percent including an incentive adder for participation in a regional transmission organization. Prior to this order, ATC had been allowed a return on equity of 12.2 percent which had been impacted by reductions for estimated refunds related to complaints filed with the FERC by several customers located within the MISO service area.

In June 2016, a federal administrative law judge ruled on an additional complaint proposing a further reduction in the base return on equity to 9.70 percent , or 10.20 percent including an incentive adder for participation in a regional transmission organization, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge's recommendation is pending. (See Note 4. Regulatory Matters.)

ATC's 10-year transmission assessment, which covers the years 2017 through 2026, identifies a need for between $2.8 billion and $3.6 billion in transmission system investments. These investments by ATC, if undertaken, are expected to be funded through a combination of internally generated cash, debt and investor contributions. As opportunities arise, we plan to make additional investments in ATC through general capital calls based upon our pro rata ownership interest in ATC.

Properties

Our Regulated Operations businesses own office and service buildings, an energy control center, repair shops, electric plants, transmission facilities and storerooms in various localities in Minnesota, Wisconsin and North Dakota. All of the electric plants are subject to mortgages, which collateralize the outstanding first mortgage bonds of Minnesota Power and SWL&P. Most of the generating plants and substations are located on real property owned by Minnesota Power or SWL&P, subject to the lien of a mortgage, whereas most of the electric lines are located on real property owned by others with appropriate easement rights or necessary permits from governmental authorities. WPPI Energy owns 20 percent of Boswell Unit 4. WPPI Energy has the right to use our transmission line facilities to transport its share of Boswell generation. (See Note 3. Jointly-Owned Facilities and Projects.)

REGULATED OPERATIONS (Continued)

Regulatory Matters

We are subject to the jurisdiction of various regulatory authorities and other organizations.

Electric Rates. All rates and contract terms in our Regulated Operations are subject to approval by applicable regulatory authorities. Minnesota Power and SWL&P design their retail electric service rates based on cost of service studies under which allocations are made to the various classes of customers as approved by the MPUC or the PSCW. Nearly all retail sales include billing adjustment clauses, which may adjust electric service rates for changes in the cost of fuel and purchased energy, recovery of current and deferred conservation improvement program expenditures and recovery of certain transmission, renewable and environmental investments.

Minnesota Public Utilities Commission. The MPUC has regulatory authority over Minnesota Power's retail service area in Minnesota, retail rates, retail services, capital structure, issuance of securities and other matters. As authorized by the MPUC, Minnesota Power also recognizes revenue under cost recovery riders for transmission, renewable and environmental investments.

2016 Minnesota General Rate Case. In November 2016, Minnesota Power filed a retail rate increase request with the MPUC seeking an average increase of approximately 9 percent for retail customers. The rate filing sought a return on equity of 10.25 percent and a 53.81 percent equity ratio. On an annualized basis, the requested final rate increase would have generated approximately $55 million in additional revenue. In December 2016, Minnesota Power filed a request to modify its original interim rate proposal reducing its requested interim rate increase to $34.7 million from the original request of approximately $49 million due to a change in its electric sales forecast. In December 2016 orders, the MPUC accepted the November 2016 filing as complete and authorized an annual interim rate increase of $34.7 million beginning January 1, 2017 .

On February 23, 2017, Minnesota Power filed an additional request to further reduce its requested interim rate increase. In an order dated April 13, 2017, the MPUC approved Minnesota Power's updated retail rate request resulting in a reduction in the annual interim rate increase to $32.2 million beginning May 1, 2017. As a result of working with intervenors and further developments as the rate review progressed, Minnesota Power's final rate request was adjusted to approximately $49 million on an annualized basis. At a hearing on January 18, 2018, the MPUC made determinations regarding Minnesota Power's general rate case including allowing a return on common equity of 9.25 percent and a 53.81 percent equity ratio. Upon commencement of final rates, we expect additional revenue of approximately $13 million on an annualized basis. Final rates are expected to commence in the fourth quarter of 2018; interim rates will be collected through this period which will be fully offset by the recognition of a corresponding reserve. As a result of the MPUC's decisions on January 18, 2018, Minnesota Power has recorded a reserve for an interim rate refund of approximately $32 million as of December 31, 2017 . The MPUC also disallowed recovery of Minnesota Power's regulatory asset for deferred fuel adjustment clause costs due to the anticipated adoption of a forward-looking fuel adjustment clause methodology resulting in a $19.5 million pre-tax charge to Fuel, Purchased Power and Gas – Utility in 2017. An order from the MPUC setting forth the effective date of final rates is expected by March 12, 2018. Minnesota Power will review this order for potential reconsideration of certain issues at that time.

As part of its decision in Minnesota Power's 2016 general rate case, the MPUC extended the depreciable lives of Boswell Unit 3, Unit 4 and common facilities to 2050 primarily to mitigate rate increases for our customers, and shortened the depreciable lives of Boswell Unit 1 and Unit 2 to 2022, resulting in a decrease to depreciation expense of approximately $25 million pre-tax in 2017.

Energy-Intensive Trade-Exposed Customer Rates. An EITE customer ratemaking law was enacted in 2015 which established that it is the energy policy of Minnesota to have competitive rates for certain industries such as mining and forest products. In 2015, Minnesota Power filed a rate schedule petition with the MPUC for EITE customers and a corresponding rider for EITE cost recovery. In a March 2016 order, the MPUC dismissed the petition without prejudice. In June 2016, Minnesota Power filed a revised EITE petition with the MPUC which included additional information on the net benefits analysis, limits on eligible customers and term lengths for the EITE discount. The rate adjustments were intended to be revenue and cash flow neutral to Minnesota Power. The MPUC approved a reduction in rates for EITE customers in a December 2016 order and subsequently approved cost recovery in an order dated April 20, 2017; collection of the discount was subject to the MPUC's review of Minnesota Power's compliance filing implementing approval of a recovery mechanism, with the subsequent order issued on October 13, 2017, that modified the order dated April 20, 2017. During 2017, Minnesota Power provided discounts of $8.6 million which were recorded as a receivable. On September 29, 2017, Minnesota Power informed its EITE customers that it had suspended the EITE discount due to a concern that it was not revenue and cash flow neutral to Minnesota Power based on an MPUC decision at a hearing on September 7, 2017, as well as the interim rate reduction and decisions in its 2016 general rate case. Based on the MPUC's decisions at a hearing on January 18, 2018, as part of Minnesota Power's 2016 general rate case, Minnesota Power reinstated the EITE discount effective January 1, 2018. Minnesota Power expects the discount to EITE customers to be approximately $15 million annually based on EITE customer current operating levels. While interim rates are in effect for Minnesota Power's 2016 general rate case, EITE discounts will offset interim rate refund reserves for non-EITE customers.

Additional regulatory proceedings pending with the MPUC are detailed in Note 4. Regulatory Matters.

Public Service Commission of Wisconsin. The PSCW has regulatory authority over SWL&P's retail sales of electricity, natural gas and water, issuances of securities and other matters.

2016 Wisconsin General Rate Case. SWL&P's current retail rates are based on a 2017 PSCW retail rate order effective August 14, 2017, that allows for a 10.5 percent return on common equity and a 55 percent equity ratio. SWL&P's retail rates prior to August 14, 2017, were based on a 2012 PSCW retail rate order that provided for a 10.9 percent return on equity. The 2017 PSCW retail rate order authorizes SWL&P to collect on average a 2.9 percent increase in rates for retail customers (3.8 percent increase in electric rates; 4.8 percent decrease in natural gas rates; and 9.8 percent increase in water rates). On an annualized basis, SWL&P expects to collect additional revenue of $2.5 million .

Federal Energy Regulatory Commission. The FERC has jurisdiction over the licensing of hydroelectric projects, the establishment of rates and charges for transmission of electricity in interstate commerce, electricity sold at wholesale (including the rates for Minnesota Power's municipal and wholesale customers), natural gas transportation, certain accounting and record-keeping practices, certain activities of our regulated utilities and the operations of ATC. FERC jurisdiction also includes enforcement of NERC mandatory electric reliability standards. Violations of FERC rules are subject to enforcement action by the FERC including financial penalties up to $1 million per day per violation. Regulatory proceedings pending with the FERC are detailed in Note 4. Regulatory Matters.

North Dakota Public Service Commission. The NDPSC has jurisdiction over site and route permitting of generation and transmission facilities in North Dakota.

Regional Organizations

Midcontinent Independent System Operator, Inc. Minnesota Power, SWL&P and ATC are members of MISO, a regional transmission organization. While Minnesota Power and SWL&P retain ownership of their respective transmission assets, their transmission networks are under the regional operational control of MISO. Minnesota Power and SWL&P take and provide transmission service under the MISO open access transmission tariff. MISO continues its efforts to oversee the safe, cost-effective delivery of electric power across all or parts of 15 states and the Canadian province of Manitoba which includes nearly 176,000 MW of generating capacity.

North American Electric Reliability Corporation. The NERC has been certified by the FERC as the national electric reliability organization. The NERC ensures the reliability of the North American bulk power system. The NERC oversees eight regional entities that establish requirements, approved by the FERC, for reliable operation and maintenance of power generation facilities and transmission systems. Minnesota Power is subject to these reliability requirements and can incur significant penalties for non-compliance.

REGULATED OPERATIONS (Continued)
Regional Organizations (Continued)

Midwest Reliability Organization (MRO). Minnesota Power and ATC are members of the MRO, one of the eight regional entities overseen by the NERC. The MRO's primary responsibilities are to: ensure compliance with mandatory reliability standards by entities who own, operate or use the interconnected, international bulk power system; conduct assessments of the grid's ability to meet electricity demand in the region; and analyze regional system events.

The MRO region spans the Canadian provinces of Saskatchewan and Manitoba, and all or parts of the states of Illinois, Iowa, Minnesota, Michigan, Montana, Nebraska, North Dakota, South Dakota and Wisconsin. The region includes more than 130 organizations that are involved in the production and delivery of electricity to more than 20 million people. These organizations include municipal utilities, cooperatives, investor-owned utilities, transmission system operators, a federal power marketing agency, Canadian Crown corporations and independent power producers.

Minnesota Legislation

Renewable Energy. Minnesota law requires 25 percent of electric utilities' applicable retail and municipal energy sales in Minnesota to be from renewable energy sources by 2025. Minnesota law also requires Minnesota Power to meet interim milestones of 12 percent by 2012, 17 percent by 2016 and 20 percent by 2020. The law allows the MPUC to modify or delay meeting a milestone if implementation will cause significant ratepayer cost or technical reliability issues. If a utility is not in compliance with a milestone, the MPUC may order the utility to construct facilities, purchase renewable energy or purchase renewable energy credits. Minnesota Power's 2015 IRP, which was filed with the MPUC in 2015 and approved with modifications by the MPUC in a July 2016 order, includes an update on its plans and progress in meeting the Minnesota renewable energy milestones through 2025. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook – EnergyForward.)

Minnesota Power continues to execute its renewable energy strategy through renewable projects that will ensure it meets the identified state mandate at the lowest cost for customers. Minnesota Power has exceeded the interim milestone requirements to date with approximately 31 percent of its applicable retail and municipal energy sales supplied by renewable energy sources in 2017 .

Minnesota Solar Energy Standard. Minnesota law requires at least 1.5 percent of total retail electric sales, excluding sales to certain customers, to be generated by solar energy by the end of 2020. At least 10 percent of the 1.5 percent mandate must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 40 kW or less and community solar garden subscriptions. In a 2016 order, the MPUC approved Camp Ripley, a 10 MW utility scale solar project at the Camp Ripley Minnesota Army National Guard base and training facility near Little Falls, Minnesota, as eligible to meet the solar energy standard and for current cost recovery. Camp Ripley was completed in the fourth quarter of 2016. In a July 2016 order, the MPUC approved a community solar garden project in northeastern Minnesota, which is comprised of a 1 MW solar array owned and operated by a third party with the output purchased by Minnesota Power and a 40 kW solar array that is owned and operated by Minnesota Power. Minnesota Power believes Camp Ripley and the community solar garden arrays will meet approximately one-third of the overall mandate. Additionally, in an order dated February 10, 2017, the MPUC approved Minnesota Power's proposal to increase the amount of solar rebates available for customer-sited solar installations and recover costs of the program through Minnesota Power's renewable cost recovery rider. The proposal to incentivize customer-sited solar installations and the community solar garden subscriptions is expected to meet a portion of the required small scale solar mandate.

Competition

Retail electric energy sales in Minnesota and Wisconsin are made to customers in assigned service territories. As a result, most retail electric customers in Minnesota do not have the ability to choose their electric supplier. Large energy users of 2 MW and above that are located outside of a municipality are allowed to choose a supplier upon MPUC approval. Minnesota Power serves 12 Large Power facilities over 10 MW, none of which have engaged in a competitive rate process. No other large commercial or small industrial customers in Minnesota Power's service territory have sought a provider outside Minnesota Power's service territory since 1994. Retail electric and natural gas customers in Wisconsin do not have the ability to choose their energy supplier. In both states, however, electricity may compete with other forms of energy. Customers may also choose to generate their own electricity, or substitute other forms of energy for their manufacturing processes.

REGULATED OPERATIONS (Continued)
Competition (Continued)

In 2017 , 5 percent of total regulated utility kWh sales were to municipal customers in Minnesota by contract. These customers have the right to seek an energy supply from any wholesale electric service provider upon contract expiration. Minnesota Power's wholesale electric contract with the Nashwauk Public Utilities Commission is effective through at least December 31, 2032. Minnesota Power wholesale electric contracts with 14 municipal customers are effective through at least December 31, 2024. In June 2016, one of Minnesota Power's municipal customers provided a contract termination notice effective June 30, 2019. (See *Electric Sales / Customers.*)

The FERC has continued with its efforts to promote a more competitive wholesale market through open-access electric transmission and other means. As a result, our electric sales to Other Power Suppliers and our purchases to supply our retail and wholesale load are made in the competitive market.

Franchises

Minnesota Power holds franchises to construct and maintain an electric distribution and transmission system in 91 cities. The remaining cities, villages and towns served by Minnesota Power do not require a franchise to operate. SWL&P serves customers under electric, natural gas or water franchises in 1 city and 14 villages or towns.

ENERGY INFRASTRUCTURE AND RELATED SERVICES

ALLETE Clean Energy

ALLETE Clean Energy focuses on developing, acquiring, and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates, in four states, approximately 535 MW of nameplate capacity wind energy generation that is contracted under PSAs of various durations. ALLETE Clean Energy also engages in the development of wind energy facilities to operate under long-term PSAs or for sale to others upon completion.

ALLETE Clean Energy believes the market for renewable energy in North America is robust, driven by several factors including environmental regulation, tax incentives, societal expectations and continual technology advances. State renewable portfolio standards, and state or federal regulations to limit GHG emissions are examples of environmental regulation or public policy that we believe will drive renewable energy development.

ALLETE Clean Energy's strategy includes the safe, reliable, optimal and profitable operation of its existing facilities. This includes a strong safety culture, the continuous pursuit of operational efficiencies at existing facilities and cost controls. ALLETE Clean Energy generally acquires facilities in liquid power markets and its strategy includes the exploration of PSA extensions upon expiration of existing contracts.

ALLETE Clean Energy will pursue growth through acquisitions or project development for others. ALLETE Clean Energy is targeting acquisitions of existing facilities up to 200 MW each, which have long-term PSAs in place for the facilities' output. At this time, ALLETE Clean Energy expects acquisitions will be primarily wind or solar facilities in North America. ALLETE Clean Energy is also targeting the development of new facilities up to 200 MW each, which will have long-term PSAs in place for the output or may be sold upon completion.

Federal production tax credit qualification is important to development project economics, and ALLETE Clean Energy invested in equipment in late 2016 and late 2017 to meet production tax credit safe harbor provisions which provides an opportunity to seek development of up to approximately 1,500 MW of qualified wind projects through 2021. ALLETE Clean Energy will also invest approximately $80 million through 2020 to requalify up to 385 WTGs at its Storm Lake I, Storm Lake II and Lake Benton wind energy facilities for production tax credits.

ENERGY INFRASTRUCTURE AND RELATED SERVICES (Continued)
ALLETE Clean Energy (Continued)

On January 3, 2017, ALLETE Clean Energy announced that it will develop a wind energy facility of up to 50 MW after securing a 25-year PSA with Montana-Dakota Utilities, which includes an option to purchase the facility upon completion. We expect Montana-Dakota Utilities to exercise the option in the first quarter of 2018; construction and sale is expected to be completed in December 2018. ALLETE Clean Energy constructed and sold a 107 MW wind energy facility to Montana-Dakota Utilities in 2015. On March 16, 2017, ALLETE Clean Energy announced it will build, own and operate a separate 100 MW wind energy facility pursuant to a 20-year PSA with Northern States Power; construction is expected to begin in late 2018.

ALLETE Clean Energy manages risk by having a diverse portfolio of assets, which includes PSA expiration, technology and geographic diversity. The current portfolio of approximately 535 MW is subject to typical variations in seasonal wind with higher wind resources typically available in the winter months. The majority of its planned maintenance leverages this seasonality and is performed during lower wind periods. The current mix of PSA expiration and geographic location for existing facilities is as follows:

Wind Energy Facility	Location	Capacity MW	PSA MW	PSA Expiration
Armenia Mountain	Pennsylvania	100.5	100%	2024
Chanarambie/Viking	Minnesota	97.5		
PSA 1			12%	2018
PSA 2			88%	2023
Condon	Oregon	50	100%	2022
Lake Benton	Minnesota	104	100%	2028
Storm Lake I	Iowa	108	100%	2019
Storm Lake II	Iowa	77		
PSA 1			90%	2019
PSA 2			10%	2032

The majority of ALLETE Clean Energy's wind operations are located on real property owned by others with appropriate easements rights or necessary consents of governmental authorities. Two of ALLETE Clean Energy's wind energy facilities are encumbered by liens against their assets securing financing.

U.S. Water Services

U.S. Water Services provides integrated water management for industry by combining chemical, equipment, engineering and service for customized solutions to reduce water and energy usage, and improve efficiency. U.S. Water Services is located in 49 states and Canada and has an established base of approximately 4,900 customers. U.S. Water Services differentiates itself from the competition by developing synergies between established solutions in engineering, equipment and chemical water treatment, and helping customers achieve efficient and sustainable use of their water and energy systems. U.S. Water Services is a leading provider to the biofuels industry, and also serves the commercial and institutional markets, food and beverage, light manufacturing, power generation, and midstream oil and gas industries, among others. U.S. Water Services principally relies upon recurring revenues from a diverse mix of industrial customers. U.S. Water Services sells certain products which are seasonal in nature, with higher demand typically realized in warmer months; generally, lower sales occur in the first quarter of each year.

Our strategy is to grow U.S. Water Services' presence in North America by adding customers, products, markets and new geographies. We believe water scarcity and a growing emphasis on conservation will continue to drive significant growth in the industrial, commercial and governmental sectors leading to organic revenue growth for U.S. Water Services. U.S. Water Services also expects to pursue periodic strategic tuck-in acquisitions with a purchase price in the $10 million to $50 million range. Priority will be given to acquisitions which expand its geographic reach, add new technology or deepen its capabilities to serve its expanding customer base.

On September 1, 2017, U.S. Water Services acquired Tonka Water for total consideration of $19.2 million. Tonka Water is a supplier of municipal and industrial water treatment systems that will expand U.S. Water Services' geographic and customer markets.

U.S. Water Services leases an office and production facility at its headquarters in Minnesota as well as various office, warehouse and production facilities across the United States.

CORPORATE AND OTHER

BNI Energy

BNI Energy is a supplier of lignite coal in North Dakota, producing approximately 4 million tons annually and has an estimated 650 million tons of lignite coal reserves. Two electric generating cooperatives, Minnkota Power and Square Butte, consume virtually all of BNI Energy's production of lignite under cost-plus fixed fee coal supply agreements extending through December 31, 2037. (See Item 1. Business – Regulated Operations – Power Supply – Long-Term Purchased Power and Note 11. Commitments, Guarantees and Contingencies.) The mining process disturbs and reclaims between 200 and 250 acres per year. Laws require that the reclaimed land be at least as productive as it was prior to mining. As of December 31, 2017 , BNI Energy had a $25.0 million asset reclamation obligation ($23.5 million as of December 31, 2016) included in Other Non-Current Liabilities on the Consolidated Balance Sheet. These costs are included in the cost-plus fixed fee contract, for which an asset reclamation cost receivable was included in Other Non-Current Assets on the Consolidated Balance Sheet. The asset reclamation obligation is guaranteed by surety bonds and a letter of credit. (See Note 11. Commitments, Guarantees and Contingencies.)

ALLETE Properties

ALLETE Properties represents our legacy Florida real estate investment. Market conditions can impact land sales and could result in our inability to cover our cost basis, operating expenses or fixed carrying costs such as community development district assessments and property taxes.

ALLETE Properties' major projects in Florida are Town Center at Palm Coast and Palm Coast Park.

Summary of Projects		**Residential**	**Non-residential**
As of December 31, 2017	**Acres** *(a)*	**Units** *(b)*	**Sq. Ft.** *(b)(c)*
Projects			
Town Center at Palm Coast	971	2,419	2,178,700
Palm Coast Park	1,025	830	2,143,000
Total Projects	1,996	3,249	4,321,700

(a) Acreage amounts are approximate and shown on a gross basis, including wetlands.
(b) Units and square footage are estimated. Density at build out may differ from these estimates.
(c) Includes retail and non-retail commercial, office, industrial, warehouse, storage and institutional square footage.

In addition to the two projects, ALLETE Properties has approximately 800 acres of other land available for sale.

In recent years, market conditions for real estate in Florida have required us to review our land inventories for impairment. In 2015, the Company reevaluated its strategy related to the real estate assets of ALLETE Properties in response to market conditions and transaction activity. The revised strategy incorporated the possibility of a bulk sale of its entire portfolio. Proceeds from a bulk sale would be strategically deployed to support growth in ALLETE Clean Energy and U.S. Water Services, collectively our Energy Infrastructure and Related Services businesses. ALLETE Properties also continues to pursue sales of individual parcels over time. ALLETE Properties will continue to maintain key entitlements and infrastructure without making additional investments or acquisitions.

In connection with implementing the revised strategy, management evaluated its impairment analysis for its real estate assets using updated assumptions to determine estimated future net cash flows on an undiscounted basis. Estimated fair values were based upon current market data and pricing for individual parcels. Our impairment analysis incorporates a probability-weighted approach considering the alternative courses of sales noted above.

Based on the results of the 2015 undiscounted cash flow analysis, the undiscounted future net cash flows were not adequate to recover the carrying value of the real estate assets leading to an adjustment of carrying value to estimated fair value. Estimated fair value was derived using Level 3 inputs, including current market interest in the property for a bulk sale of its entire portfolio, and discounted cash flow analysis of estimated selling price for sales over time. As a result, a non-cash impairment charge of $36.3 million was recorded in 2015 to reduce the carrying value of the real estate to its estimated fair value.

In 2017 and 2016, our qualitative assessments indicated that the cash flows were adequate to recover the carrying value of ALLETE Properties real estate assets. As a result, no impairment was recorded in 2017 or 2016.

Seller Financing. ALLETE Properties occasionally provides seller financing to certain qualified buyers. As of December 31, 2017 , outstanding finance receivables were $15.5 million , net of reserves, with maturities through 2022 . These finance receivables accrue interest at market-based rates and are collateralized by the financed properties.

Regulation. A substantial portion of our development properties in Florida are subject to federal, state and local regulations, and restrictions that may impose significant costs or limitations on our ability to develop the properties. Much of our property is vacant land and some is located in areas where development may affect the natural habitats of various protected wildlife species or in sensitive environmental areas such as wetlands.

Non-Rate Base Generation and Miscellaneous

Corporate and Other also includes other business development and corporate expenditures, unallocated interest expense, a small amount of non-rate base generation, approximately 5,000 acres of land in Minnesota, and earnings on cash and investments.

As of December 31, 2017 , non-rate base generation consists of 29 MW of generation at Rapids Energy Center. In 2017 , we sold 0.1 million MWh of non-rate base generation (0.1 million MWh in 2016 and in 2015).

Non-Rate Base Power Supply	Unit No.	Year Installed	Year Acquired	Net Capability (MW)
Rapids Energy Center *(a)*				
in Grand Rapids, MN				
Steam – Biomass *(b)*	6 & 7	1969, 1980	2000	27
Hydro	4 & 5	1917, 1948	2000	2

(a) The net generation is primarily dedicated to the needs of one customer, UPM Blandin in Grand Rapids, Minnesota. (See Item 7. Management's Discussion and Analysis – Outlook – Industrial Customers and Prospective Additional Load.)
(b) Rapids Energy Center's fuel supply is supplemented by coal.

ENVIRONMENTAL MATTERS

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. A number of regulatory changes to the Clean Air Act, the Clean Water Act and various waste management requirements have recently been promulgated by both the EPA and state authorities. Minnesota Power's facilities are subject to additional requirements under many of these regulations. Minnesota Power is reshaping its generation portfolio, over time, to reduce its reliance on coal, has installed cost-effective emission control technology, and advocates for sound science and policy during rulemaking implementation.

We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits have been obtained. We anticipate that with many state and federal environmental regulations finalized, or to be finalized in the near future, potential expenditures for future environmental matters may be material and may require significant capital investments. Minnesota Power has evaluated various environmental compliance scenarios using possible outcomes of environmental regulations to project power supply trends and impacts on customers.

We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated based on current law and existing technologies. Accruals are adjusted as assessment and remediation efforts progress or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in the Consolidated Balance Sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are expensed unless recoverable in rates from customers. (See Note 11. Commitments, Guarantees and Contingencies.)

EMPLOYEES

As of December 31, 2017 , ALLETE had 2,017 employees, of which 1,972 were full-time.

Minnesota Power and SWL&P have an aggregate of 517 employees who are members of the International Brotherhood of Electrical Workers (IBEW) Local 31. The labor agreements with IBEW Local 31 expired on January 31, 2018. Negotiations are proceeding and we believe ratified agreements will be agreed upon in the first quarter of 2018. Minnesota Power, SWL&P and IBEW Local 31 are operating under the expired labor agreements until new contracts are agreed upon.

BNI Energy has 179 employees, of which 136 are members of IBEW Local 1593. The labor agreement with IBEW Local 1593 expires on March 31, 2019.

AVAILABILITY OF INFORMATION

ALLETE makes its SEC filings, including its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(e) or 15(d) of the Securities Exchange Act of 1934, available free of charge on ALLETE's website, www.allete.com, as soon as reasonably practicable after they are electronically filed with or furnished to the SEC.

EXECUTIVE OFFICERS OF THE REGISTRANT

As of February 15, 2018 , these are the executive officers of ALLETE:

Executive Officers	Initial Effective Date
Alan R. Hodnik, Age 58	
Chairman, President and Chief Executive Officer	May 10, 2011
President and Chief Executive Officer	May 1, 2010
Robert J. Adams, Age 55	
Senior Vice President and Chief Financial Officer	March 4, 2017
Senior Vice President – Energy-Centric Businesses and Chief Risk Officer	November 14, 2015
Vice President – Energy-Centric Businesses and Chief Risk Officer	June 23, 2014
Vice President – Business Development and Chief Risk Officer	May 13, 2008
Deborah A. Amberg, Age 52	
Senior Vice President, Chief Strategy Officer – Regulated Operations and President – SWL&P	November 26, 2016
Senior Vice President, General Counsel and Secretary	January 1, 2006
Patrick L. Cutshall, Age 52	
Vice President and Corporate Treasurer	December 18, 2017
Treasurer	January 1, 2016
Steven W. Morris, Age 56	
Vice President, Controller and Chief Accounting Officer	December 24, 2016
Controller	March 3, 2014
Patrick K. Mullen, Age 57	
Senior Vice President – External Affairs	April 10, 2017
Bradley W. Oachs, Age 60	
Senior Vice President and President – Regulated Operations	November 26, 2016
Bethany M. Owen, Age 52	
Senior Vice President and Chief Legal and Administrative Officer	November 26, 2016

All of the executive officers have been employed by us for more than five years in executive or management positions. Prior to election to the position listed above, the following executives held other positions with the Company during the past five years.

Mr. Morris was Director – Accounting.
Mr. Cutshall was Director – Investments and Tax; Director – Investments.
Mr. Oachs was Chief Operating Officer – Minnesota Power.
Ms. Owen was Vice President – Information Technology Solutions and President – SWL&P.
Mr. Mullen was Vice President – Marketing and Corporate Communications.

There are no family relationships between any of the executive officers. All officers and directors are elected or appointed annually.

The present term of office of the executive officers listed in the preceding table extends to the first meeting of our Board of Directors after the next annual meeting of shareholders. Both meetings are scheduled for May 8, 2018.

Item 1A. Risk Factors

The risks and uncertainties discussed below could materially affect our business operations, financial position, results of operations and cash flows, and should be carefully considered by stakeholders. The risks and uncertainties in this section are not the only ones we face; additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations, financial position, results of operations and cash flows. Accordingly, the risks described below should be carefully considered together with other information set forth in this report and in future reports that we file with the SEC.

Entity-wide Risks

We rely on access to financing sources and capital markets. If we do not have access to capital on acceptable terms or are unable to obtain capital when needed, our ability to execute our business plans, make capital expenditures or pursue other strategic actions that we may otherwise rely on for future growth would be adversely affected.

We rely on access to financing sources and the capital markets, on acceptable terms and at reasonable costs, as sources of liquidity for capital requirements not satisfied by our cash flows from operations. Market disruptions or a downgrade of our credit ratings may increase the cost of borrowing or adversely affect our ability to access and financing costs in the capital markets. Such disruptions or causes of a downgrade could include but are not limited to: the effects of the TCJA on the Company's cash flow metrics; a loss of, or a reduction in sales to, Large Power Customers if we are unable to offset the related lost margins; weaker operating performance; adverse regulatory outcomes; disproportionate increase in the contribution to net income from our Energy Infrastructure and Related Services businesses as compared to that from our Regulated Operations; deteriorating economic or capital market conditions; or volatility in commodity prices.

If we are not able to access capital on acceptable terms in sufficient amounts and when needed, or at all, the ability to maintain our businesses or to implement our business plans would be adversely affected.

Recent U.S. tax legislation could adversely impact our financial position, results of operations and cash flows.

On December 22, 2017, the TCJA was enacted into law. The TCJA has significantly changed the U.S. Internal Revenue Code and the taxation of corporations. The TCJA is unclear in certain respects and will require interpretations and the promulgation of regulations by the Internal Revenue Service, as well as state tax authorities and it could be subject to potential amendments and technical corrections. The regulatory treatment of the impacts of the TCJA will be subject to the discretion of the FERC and state regulatory authorities.

On February 6, 2018, Standard & Poor's downgraded its ratings outlook for ALLETE to negative from stable as a result, among other reasons, of the potential negative impact of the TCJA on certain financial metrics used by credit rating agencies to rate us. It is unclear when or how the capital markets and the credit rating agencies will ultimately respond. Further, there may be other adverse effects resulting from the TCJA or regulatory agency responses to the TCJA that we have not yet identified. We are still quantifying the impacts of the TCJA on our businesses, and have reflected estimates for the impacts in our Consolidated Financial Statements as of December 31, 2017, which may be adjusted in future periods as more information becomes available. The reduction in the federal corporate income tax rate required us to remeasure our existing deferred income tax balances as of the date of enactment, resulting in a non-cash benefit to earnings in our ALLETE Clean Energy and U.S. Water Services segments as well as a non-cash expense at our Corporate and Other businesses. The remeasurement of the existing deferred income tax assets and liabilities for our Regulated Operations segment was recorded as regulatory assets, regulatory liabilities, and a change to our investment in ATC resulting in no material impact on the 2017 results of operations for this segment. The benefits of the TCJA for customers of Minnesota Power and SWL&P are expected to be passed back to those customers over time primarily based upon the normalization provisions of the U.S. Internal Revenue Code over the life of the related property, plant and equipment with the remainder passed back based upon the determinations of regulatory authorities. The decrease in our investment in ATC is expected to be amortized into earnings over time. The final amount and timing over which the benefits of the TCJA will be passed back to customers has not been determined, and therefore, the full cash flow impacts are still uncertain.

A deterioration in general economic conditions may have adverse impacts on our financial position, results of operations and cash flows.

If economic conditions deteriorate on a national or regional level, it may have a negative impact on the Company's financial position, results of operations and cash flows as well as on our customers. This impact may include volatility and unpredictability in the demand for the products and services offered by our businesses, the loss of existing customers, tempered growth strategies, production cutbacks or customer bankruptcies. An uncertain economy could also adversely affect expenses including pension costs, interest costs, and uncollectible accounts, or lead to reductions in the value of certain real estate and other investments.

We are subject to extensive state and federal legislation and regulation, compliance with which could have an adverse effect on our businesses.

We are subject to, and affected by, extensive state and federal legislation and regulation. If it was determined that our businesses failed to comply with applicable laws and regulations, we could become subject to fines or penalties or be required to implement additional compliance measures or actions, the cost of which could be material. Adoption of new laws, rules, regulations, principles, or practices by federal and state agencies, or changes to or a failure to comply with current laws, rules, regulations, principles, or practices and their interpretations, could have an adverse effect on our financial position, results of operations and cash flows.

The inability to attract and retain a qualified workforce including, but not limited to, executive officers, key employees and employees with specialized skills, could have an adverse effect on our operations.

The success of our business heavily depends on the leadership of our executive officers and key employees to implement our business strategy. The inability to maintain a qualified workforce including, but not limited to, executive officers, key employees and employees with specialized skills, may negatively affect our ability to service our existing or new customers, or successfully manage our business or achieve our business objectives. Personnel costs may increase due to competitive pressures or terms of collective bargaining agreements with union employees.

Market performance and other changes could decrease the value of pension and other postretirement benefit plan assets, which may result in significant additional funding requirements and increased annual expenses.

The performance of the capital markets impacts the values of the assets that are held in trust to satisfy future obligations under our pension and other postretirement benefit plans. We have significant obligations to these plans and the trusts hold significant assets. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected rates of return. A decline in the market value of the pension and other postretirement benefit plan assets would increase the funding requirements under our benefit plans if asset returns do not recover. Additionally, our pension and other postretirement benefit plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit expense and funding requirements. Our pension and other postretirement benefit plan costs are generally recoverable in our electric rates as allowed by our regulators or through our cost-plus fixed fee coal supply agreements at BNI Energy; however, there is no certainty that regulators will continue to allow recovery of these rising costs in the future.

We are exposed to significant reputational risk.

The Company could suffer negative impacts to its reputation as a result of operational incidents, violations of corporate compliance policies, regulatory violations, or other events which may result in negative customer perception and increased regulatory oversight, each of which could have an adverse effect on our financial position, results of operations and cash flows.

Catastrophic events, such as natural disasters and acts of war, may adversely affect our operations.

Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, or similar occurrences, as well as acts of war, could adversely affect the Company's facilities, operations, financial position, results of operations and cash flows. Although the Company has contingency plans and employs crisis management to respond and recover operations in the event of a severe disruption resulting from such events, these measures may not be successful. Furthermore, despite these measures, if such an occurrence were to occur, our financial position, results of operations and cash flows could be adversely affected.

We are vulnerable to acts of terrorism or cybersecurity attacks.

Our operations may be targets of terrorist activities, including cybersecurity attacks, which could disrupt our ability to produce or distribute some portion of our products. There have been cyber security attacks on U.S. energy infrastructure in the past and there may be such attacks in the future. Our generation, transmission and distribution facilities, information technology systems and other infrastructure facilities and systems could be direct targets of, or otherwise be materially adversely affected by such activities. Computer viruses, terrorism, theft and sabotage could impact our systems and facilities, or those of third parties on which we rely, which may disrupt our operations and adversely impact our results of operations. Our businesses require the continued operation of sophisticated information technology systems and network infrastructure. Our technology systems, or those of third parties on which we rely, may be vulnerable to disability, failures or unauthorized access due to hacking, viruses, acts of war or terrorism and other causes. If those technology systems fail or are breached and not recovered in a timely manner, we may be unable to perform critical business functions and sensitive, confidential and other data could be compromised, which could have an adverse effect on our financial position, results of operations and cash flows.

Government challenges to our tax positions, as well as tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions, could adversely affect our results of operations and liquidity.

We are required to make judgments in order to estimate federal and state tax obligations. These judgments include reserves for potential adverse outcomes for tax positions that may be challenged by tax authorities. The obligations, which include income taxes and taxes other than income taxes, involve complex matters that ultimately could be litigated. We also estimate our ability to use tax benefits, including those in the form of carryforwards and tax credits that are recorded as deferred tax assets on our Consolidated Balance Sheet. A disallowance of these tax benefits could have an adverse impact on our financial position, results of operations and cash flows.

We plan to utilize our carryforwards and tax credits in the future to reduce our income tax obligations. If we cannot generate enough taxable income in the future to utilize all of our carryforwards and tax credits before they expire, we may incur adverse charges to earnings. If federal or state tax authorities disagree with the deductions resulting from our tax planning strategies, our financial position, results of operations and cash flows may be adversely impacted.

Regulated Operations Risks

Our results of operations could be negatively impacted if our Large Power Customers experience an economic downturn, incur work stoppages, fail to compete effectively, experience decreased demand or experience a decline in prices for their product.

Minnesota Power's nine Large Power Customers accounted for 25 percent of our 2017 consolidated operating revenue (22 percent in 2016 and in 2015), of which one of these customers accounted for approximately 10 percent of consolidated revenue in 2017 (8 percent in 2016 and in 2015). These customers are involved in cyclical industries that by their nature are adversely impacted by economic downturns and are subject to strong competition in the marketplace. Additionally, the North American paper and pulp industry also faces declining demand due to the impact of electronic substitution for print and changing customer needs.

Accordingly, if our customers experience an economic downturn, incur a work stoppage (including strikes, lock-outs or other events), fail to compete effectively, experience decreased demand or experience a decline in prices for their product, there could be adverse effects on their operations and, consequently, this could have a negative impact on our results of operations if we are unable to remarket at similar prices the energy that would otherwise have been sold to such Large Power Customers.

Our utility operations are subject to an extensive legal and regulatory framework under federal and state laws as well as regulations imposed by other organizations that may have a negative impact on our business and results of operations.

We are subject to an extensive legal and regulatory framework imposed under federal and state law including regulations administered by the FERC, MPUC, MPCA, PSCW, NDPSC and EPA as well as regulations administered by other organizations including the NERC. These laws and regulations relate to allowed rates of return, capital structure, financings, rate and cost structure, acquisition and disposal of assets and facilities, construction and operation of generation, transmission and distribution facilities (including the ongoing maintenance and reliable operation of such facilities), recovery of purchased power costs and capital investments, approval of integrated resource plans and present or prospective wholesale and retail competition, among other things. Energy policy initiatives at the state or federal level could increase incentives for distributed generation, municipal utility ownership, or local initiatives could introduce generation or distribution requirements that could change the current integrated utility model. Our transmission systems and electric generation facilities are subject to the NERC mandatory reliability standards, including cybersecurity standards. Compliance with these standards may lead to increased operating costs and capital expenditures. If it was determined that we were not in compliance with these mandatory reliability standards or other statutes, rules and orders, we could incur substantial monetary penalties and other sanctions, which could adversely affect our results of operations.

These laws and regulations significantly influence our operations and may affect our ability to recover costs from our customers. We are required to have numerous permits, licenses, approvals and certificates from the agencies and other organizations that regulate our business. We believe we have obtained the necessary permits, licenses, approvals and certificates for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies and other organizations. Changes in regulations or the adoption of new regulations could have an adverse impact on our results of operations.

Our ability to obtain rate adjustments to maintain reasonable rates of return depends upon regulatory action under applicable statutes and regulations, and we cannot provide assurance that rate adjustments will be obtained or reasonable authorized rates of return on capital will be earned. Minnesota Power and SWL&P, from time to time, file general rate cases with, or otherwise seek cost recovery authorization from, federal and state regulatory authorities. If Minnesota Power and SWL&P do not receive an adequate amount of rate relief in general rate cases, including if rates are reduced, if increased rates are not approved on a timely basis or costs are otherwise unable to be recovered through rates, or if cost recovery is not granted at the requested level, we may experience an adverse impact on our financial position, results of operations and cash flows. We are unable to predict the impact on our business and results of operations from future legislation or regulatory activities of any of these agencies or organizations.

Our operations present certain environmental risks that could adversely affect our financial position and results of operations, including effects of environmental laws and regulations, physical risks associated with climate change and initiatives designed to reduce the impact of GHG emissions.

We are subject to extensive environmental laws and regulations affecting many aspects of our present and future operations, including air quality, water quality and usage, waste management, reclamation, hazardous wastes, avian mortality and natural resources. These laws and regulations can result in increased capital expenditures, environmental emission allowance trading, operating and other costs, as a result of compliance, remediation, containment and monitoring obligations, particularly with regard to laws relating to power plant emissions, coal ash, water discharge and wind energy facilities.

These laws and regulations could restrict the output of some existing facilities, limit the use of some fuels in the production of electricity, require the installation of additional pollution control equipment, require participation in environmental emission allowance trading, and lead to other environmental considerations and costs, which could have an adverse impact on our business, operations and results of operations.

These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Violations of these laws and regulations could expose us to regulatory and legal proceedings, disputes with, and legal challenges by, governmental authorities and private parties, as well as potential significant civil fines criminal penalties and other sanctions.

Existing environmental regulations may be revised and new environmental regulations may be adopted or become applicable to us. Revised or additional regulations which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have an adverse effect on our results of operations.

The scientific community generally accepts that emissions of GHG are linked to global climate change. Physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, and other related phenomena, could affect some, or all, of our operations. Severe weather or other natural disasters could be destructive, which could result in increased costs. An extreme weather event within our utility service areas can also directly affect our capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. These all have the potential to adversely affect our business and operations.

There is significant uncertainty regarding if and when new laws or regulations will be adopted to reduce GHGs and the impact any such laws or regulations would have on us. In 2017 , coal was the primary fuel source for 70 percent of the energy produced by our generating facilities. Any future limits on GHG emissions would likely require us to incur significant capital expenditures and increases in operating costs, which if significant, could result in the closure of certain coal-fired energy centers, an impairment of assets, or otherwise adversely affect our results of operations, particularly if such expenditures and costs are not fully recoverable from customers.

We cannot predict the amount or timing of all future expenditures related to environmental matters because of uncertainty as to applicable regulations or requirements. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Violations of certain environmental statutes, rules and regulations could expose ALLETE to third party disputes and potentially significant monetary penalties, as well as other sanctions for non-compliance.

The operation and maintenance of our electric generation and transmission facilities are subject to operational risks that could adversely affect our financial position, results of operations and cash flows.

The operation of generating facilities involves many risks, including start-up operations risks, breakdown or failure of facilities, the dependence on a specific fuel source, inadequate fuel supply, availability of fuel transportation, or the impact of unusual or adverse weather conditions or other natural events, as well as the risk of performance below expected levels of output or efficiency. A significant portion of our facilities contain older generating equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to continue operating at peak efficiency. Generation and transmission facilities and equipment are also likely to require periodic upgrades and improvements due to changing environmental standards and technological advances. We could be subject to costs associated with any unexpected failure to produce or deliver power, including failure caused by breakdown or forced outage, as well as repairing damage to facilities due to storms, natural disasters, wars, sabotage, terrorist acts and other catastrophic events.

Our ability to successfully and timely complete capital improvements to existing facilities or other capital projects is contingent upon many variables.

We expect to incur significant capital expenditures in making capital improvements to our existing electric generation and transmission facilities and in the development and construction of new electric generation and transmission facilities. Should any such efforts be unsuccessful or not completed in a timely manner, we could be subject to additional costs or impairments which could have an adverse impact on our financial position and results of operation.

Our electric generating operations may not have access to adequate and reliable transmission and distribution facilities necessary to deliver electricity to our customers.

We depend on our own transmission and distribution facilities, as well as facilities owned by other utilities, to deliver the electricity produced and sold to our customers, and to other energy suppliers. If transmission capacity is inadequate, our ability to sell and deliver electricity may be limited. We may have to forgo sales or may have to buy more expensive wholesale electricity that is available in the capacity-constrained area. In addition, any infrastructure failure that interrupts or impairs delivery of electricity to our customers could negatively impact the satisfaction of our customers, which could have an adverse impact on our business and results of operations.

Our results of operations could be impacted by declining wholesale power prices.

Wholesale prices for electricity have declined in recent years primarily due to low natural gas prices. If there are reductions in demand from customers or if we lose customers, we will market any available power to Other Power Suppliers in an effort to mitigate any earnings impact. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations. Due to the low wholesale prices for electricity, we can make no assurances that our power marketing efforts would fully offset any reduction in earnings resulting from the lower demand from existing customers or the loss of customers.

The price of electricity and fuel may be volatile.

Volatility in market prices for electricity and fuel could adversely impact our financial position and results of operations and may result from:

- severe or unexpected weather conditions and natural disasters;
- seasonality;
- changes in electricity usage;
- transmission or transportation constraints, inoperability or inefficiencies;
- availability of competitively priced alternative energy sources;
- changes in supply and demand for energy;
- changes in power production capacity;
- outages at our generating facilities or those of our competitors;
- availability of fuel transportation;
- changes in production and storage levels of natural gas, lignite, coal, crude oil and refined products;
- wars, sabotage, terrorist acts or other catastrophic events; and
- federal, state, local and foreign energy, environmental, or other regulation and legislation.

Fluctuations in our fuel and purchased power costs related to our retail and municipal customers are passed on to customers through the fuel adjustment clause. Volatility in market prices for our fuel and purchase power costs primarily impacts our sales to Other Power Suppliers.

Demand for energy may decrease.

Our results of operations are impacted by the demand for energy in our service territories. There could be lower demand for energy due to a loss of customers as a result of economic conditions, customers constructing their own generation facilities, higher costs and rates charged to customers, or loss of service territory or franchises. Further, energy conservation and technological advances that increased energy efficiency may temporarily or permanently reduce the demand for energy products. In addition, we are impacted by state and federal regulations requiring mandatory conservation measures, which would reduce the demand for energy products. Continuing technology improvements and regulatory developments may make customer and third party-owned generation technologies such as rooftop solar systems, WTGs, microturbines and battery storage systems more cost effective and feasible for more of our customers. If more customers utilize their own generation, demand for energy from us would decline. There may not be future economic growth opportunities that would enable us to replace the lost energy demand from these customers. Therefore, a decrease in demand for energy could adversely impact our financial position, results of operations and cash flows.

We may not be able to successfully implement our strategic objectives of growing load at our utilities if current or potential industrial or municipal customers are unable to successfully implement expansion plans, including the inability to obtain necessary governmental permits.

As part of our long-term strategy, we pursue new wholesale and retail loads in and around our service territories. Currently, there are several companies in northeastern Minnesota that are in the process of developing natural resource-based projects that represent long-term growth potential and load diversity for our Regulated Operations businesses. These projects may include construction of new facilities and restarts of old facilities, both of which require permitting and approvals to be obtained before the projects can be successfully implemented. If a project does not obtain any necessary governmental (including environmental) permits and approvals or if these customers are unable to successfully implement expansion plans, our long-term strategy and thus our results of operations could be adversely impacted.

Energy Infrastructure and Related Services Risks

The inability to successfully manage and grow our Energy Infrastructure and Related Services businesses could adversely affect our results of operations.

Our Energy Infrastructure and Related Services businesses consist of ALLETE Clean Energy and U.S. Water Services. The Company's strategy for these businesses includes adding customers, products, and new geographies, project development for others and growth through acquisitions. This strategy depends, in part, on the Company's ability to successfully identify and evaluate acquisition opportunities and consummate acquisitions on acceptable terms. The Company may compete with other companies for these acquisition opportunities, which may increase the Company's cost of making acquisitions and the Company may be unsuccessful in pursuing these acquisition opportunities. These companies may be able to pay more for acquisitions and may be able to identify, evaluate, bid for and purchase a greater number of assets than the Company's financial or human resources permit. Additionally, tax law changes may adversely impact the economic characteristics of potential acquisitions or investments. If the Company is unable to execute its strategy of growth through acquisitions, project development for others, or the addition of new customers, products and geographies, it may impede our long-term objectives and business strategy.

Acquisitions are subject to uncertainties. If we are unable to successfully integrate and manage future acquisitions or strategic investments, this could have an adverse impact on our results of operations. Our actual results may also differ from our expectations due to factors such as the ability to obtain timely regulatory or governmental approvals, integration and operational issues and the ability to retain management and other key personnel.

U.S. Water Services principally relies upon recurring revenues from a diverse mix of industrial customers. Some of these customers can be adversely affected by low commodity prices such as those for ethanol and oil which may cause these customers to purchase less of U.S. Water Services' products and services. If U.S. Water Services is unable to retain its existing customers, add new customers, or if it experiences reduced demand for its products and services, adverse impacts on our results of operations could occur that would prevent us from achieving our future growth expectations.

The generation of electricity from ALLETE Clean Energy's wind energy facilities depends heavily on suitable meteorological conditions.

ALLETE Clean Energy's facilities are geographically diverse; however, if wind conditions are unfavorable, ALLETE Clean Energy's electricity generation and revenue from its wind energy facilities may be substantially below its expectations. The electricity produced, production tax credits received, and revenues generated by a wind energy facility are highly dependent on suitable wind conditions and associated weather conditions, which are beyond ALLETE Clean Energy's control. Furthermore, components of its systems could be damaged by severe weather, such as hailstorms, lightning or tornadoes. In addition, replacement and spare parts for key components of ALLETE Clean Energy's diverse turbine portfolio may be difficult or costly to acquire or may be unavailable. Unfavorable weather and atmospheric conditions could impair the effectiveness of ALLETE Clean Energy's assets or reduce their output beneath their rated capacity or require shutdown of key equipment, impeding operation of its wind energy facilities.

The operation and maintenance of ALLETE Clean Energy's electric generation facilities are subject to operational risks that could adversely affect our financial position, results of operations and cash flows.

The operation of generating facilities involves many risks, including start-up operations risks, breakdown or failure of facilities, the dependence on the availability of wind resources, or the impact of unusual, adverse weather conditions or other natural events, as well as the risk of performance below expected levels of output or efficiency. A portion of our facilities contain older generating equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to continue operating at peak efficiency. We could be subject to costs associated with any unexpected failure to produce and deliver power, including failure caused by breakdown or forced outage, as well as repairing damage to facilities due to storms, natural disasters, wars, sabotage, terrorist acts and other catastrophic events.

As contracts with its counterparties expire, ALLETE Clean Energy may not be able to replace them with agreements on similar terms.

ALLETE Clean Energy is party to PSAs which expire in various years between 2018 and 2032. These PSA expirations are prior to the end of the estimated useful lives of the respective wind energy facilities. If, for any reason, ALLETE Clean Energy is unable to enter into new agreements with existing or new counterparties on similar terms once the current agreements expire, or sell energy in the wholesale market resulting in similar revenue, our financial position, results of operations and cash flows could be adversely affected.

Counterparties to ALLETE Clean Energy's offtake agreements may not fulfill their obligations.

ALLETE Clean Energy is party to PSAs under various durations with a limited number of creditworthy counterparties. If, for any reason, any of the counterparties under these agreements do not fulfill their related contractual obligations, and ALLETE Clean Energy is unable to remarket the energy resulting in similar revenue, our financial position, results of operations and cash flows could be adversely affected.

ALLETE has a significant amount of goodwill and intangible assets. A determination that goodwill or intangible assets have been impaired could result in a significant non-cash charge to earnings.

We had approximately $226 million of goodwill and intangible assets recorded on our Consolidated Balance Sheet as of December 31, 2017 , relating to our initial acquisition of U.S. Water Services in 2015 as well as U.S. Water Services' subsequent acquisitions. If we change our business strategy, fail to deliver on our projected results or if market or other conditions adversely affect the operations of U.S. Water Services, we may be required to record an impairment charge. Declines in projected operating cash flows at U.S. Water Services could also result in an impairment charge. An impairment charge would result in a non-cash charge to earnings that could have an adverse effect on our results of operations.

Corporate and Other Risks

BNI Energy may be adversely impacted by its exposure to customer concentration, and environmental laws and regulations.

BNI Energy sells lignite coal to two electric generating cooperatives, Minnkota Power and Square Butte, and could be adversely impacted if these customers were unable or unwilling to fulfill their related contractual obligations. In addition, BNI Energy and its customers may be adversely impacted by environmental laws and regulations which could have an adverse effect on our financial position, results of operations and cash flows.

Real estate market conditions where our legacy Florida real estate investment is located may not improve.

The Company's strategy related to the real estate assets of ALLETE Properties incorporates the possibility of a bulk sale of its entire portfolio, in addition to sales over time, however, continued adverse market conditions could impact the timing of land sales, which could result in little to no sales, while still incurring operating expenses such as community development district assessments and property taxes, resulting in net operating losses at ALLETE Properties. Furthermore, weak market conditions could put the properties at risk for an impairment charge. An impairment charge would result in a non-cash charge to earnings that could have an adverse effect on our results of operations.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A discussion of our properties is included in Item 1. Business and is incorporated by reference herein.

Item 3. Legal Proceedings

Discussions of material regulatory and environmental proceedings are included in Note 4. Regulatory Matters and Note 11. Commitments, Guarantees and Contingencies, and are incorporated by reference herein.

We are involved in litigation arising in the normal course of business. Also in the normal course of business, we are involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, and compliance with regulations, rate base and cost of service issues, among other things. We do not expect the outcome of these matters to have a material effect on our financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires issuers to include in periodic reports filed with the SEC certain information relating to citations or orders for violations of standards under the Federal Mine Safety and Health Act of 1977 (Mine Safety Act). Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and this Item are included in Exhibit 95 to this Form 10-K.

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the NYSE under the symbol ALE. We have paid dividends, without interruption, on our common stock since 1948. A quarterly dividend of $0.56 per share on our common stock is payable on March 1, 2018, to the shareholders of record on February 15, 2018. The timing and amount of future dividends will depend upon earnings, cash requirements, the financial condition of the Company, applicable government regulations and other factors deemed relevant by the ALLETE Board of Directors.

The following table shows dividends declared per share, and the high and low prices of our common stock for the periods indicated as reported by the NYSE:

	2017			2016		
	Price Range		Dividends	Price Range		Dividends
Quarter	High	Low	Declared	High	Low	Declared
First	$68.38	$61.64	$0.535	$58.34	$48.26	$0.52
Second	$74.59	$66.81	0.535	$64.69	$53.47	0.52
Third	$79.61	$69.79	0.535	$65.41	$52.50	0.52
Fourth	$81.24	$72.96	0.535	$66.92	$56.48	0.52
Annual Total			$2.14			$2.08

As of February 1, 2018, there were approximately 23,000 common stock shareholders of record.

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities (Continued)

Performance Graph.

The following graph compares ALLETE's cumulative Total Shareholder Return on its common stock with the cumulative return of the S&P 500 Index and the Philadelphia Utility Index. The S&P 500 Index is a capitalization-weighted index of 500 stocks designed to measure performance of the broad domestic economy through changes in the aggregate market value of 500 stocks representing all major industries. Because this composite index has a broad industry base, its performance may not closely track that of a composite index comprised solely of electric utilities. The Philadelphia Utility Index is a capitalization-weighted index of 20 utility companies involved in the generation of electricity.

The calculations assume a $100 investment on December 31, 2012, and reinvestment of dividends.

	2012	2013	2014	2015	2016	2017
ALLETE	$100	$127	$146	$140	$183	$218
S&P 500 Index	$100	$132	$150	$153	$171	$208
Philadelphia Utility Index	$100	$111	$143	$152	$178	$201

Item 6. Selected Financial Data

	2017	2016	2015	2014	2013
Millions Except Per Share Amounts					
Operating Revenue *(a)*	$1,419.3	$1,339.7	$1,486.4	$1,136.8	$1,018.4
Operating Expenses *(a)*	$1,189.5	$1,116.2	$1,275.7	$948.0	$864.3
Net Income *(b)*	$172.2	$155.8	$141.5	$125.5	$104.7
Less: Non-Controlling Interest in Subsidiaries *(c)*	—	0.5	0.4	0.7	—
Net Income Attributable to ALLETE *(b)*	$172.2	$155.3	$141.1	$124.8	$104.7
Common Stock Dividends	108.7	102.7	97.9	83.8	75.2
Earnings Retained in Business *(b)*	$63.5	$52.6	$43.2	$41.0	$29.5
Shares Outstanding					
Year-End	51.1	49.6	49.1	45.9	41.4
Average *(d)*					
Basic	50.8	49.3	48.3	42.9	39.7
Diluted	51.0	49.5	48.4	43.1	39.8
Diluted Earnings Per Share *(b)*	$3.38	$3.14	$2.92	$2.90	$2.63
Total Assets *(e)*	$5,080.0	$4,876.9	$4,864.4	$4,329.1	$3,458.6
Long-Term Debt	$1,439.2	$1,370.4	$1,556.7	$1,263.2	$1,074.9
Return on Common Equity *(b)*	8.6%	8.4%	8.0%	8.6%	8.3%
Common Equity Ratio	58%	55%	53%	54%	55%
Dividends Declared per Common Share	$2.14	$2.08	$2.02	$1.96	$1.90
Dividend Payout Ratio *(b)*	63%	66%	69%	68%	72%
Book Value Per Share at Year-End	$40.46	$38.17	$37.18	$35.04	$32.43
Capital Expenditures by Segment					
Regulated Operations	$177.1	$121.8	$224.4	$583.5	$326.3
ALLETE Clean Energy	56.1	106.9	8.6	4.2	—
U.S. Water Services	4.4	3.7	2.9	—	—
Corporate and Other	28.9	15.4	15.9	16.6	13.2
Total Capital Expenditures	$266.5	$247.8	$251.8	$604.3	$339.5

(a) In 2015, operating revenue and operating expenses included the construction and sale of a wind energy facility from ALLETE Clean Energy to Montana-Dakota Utilities for $197.7 million and $162.9 million, respectively.

(b) The year ended December 31, 2017, includes the impact of the remeasurement of deferred income tax assets and liabilities resulting from the TCJA. (See Note 1. Operations and Significant Accounting Policies.)

(c) The non-controlling interest related to ALLETE Clean Energy's Condon wind energy facility was acquired in April 2016. (See Note 6. Acquisitions.)

(d) Excludes unallocated ESOP shares in 2013 and 2014.

(e) During the first quarter of 2017, the Company identified an error related to the deferred income tax treatment associated with its Wholesale and Retail Contra AFUDC Regulatory Liability resulting in a decrease in Regulatory Assets and Deferred Income Taxes. The periods presented have been revised for the correction of the error. (See Note 1. Operations and Significant Accounting Policies.)

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with our Consolidated Financial Statements and notes to those statements and the other financial information appearing elsewhere in this report. In addition to historical information, the following discussion and other parts of this Form 10-K contain forward-looking information that involves risks and uncertainties. Readers are cautioned that forward-looking statements should be read in conjunction with our disclosures in this Form 10-K under the headings: "Forward-Looking Statements" located on page 6 and "Risk Factors" located in Item 1A. The risks and uncertainties described in this Form 10-K are not the only risks facing our Company. Additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations. Our business, financial condition or results of operations could suffer if the risks are realized.

Overview

Basis of Presentation. We present three reportable segments: Regulated Operations, ALLETE Clean Energy and U.S. Water Services. Our segments were determined in accordance with the guidance on segment reporting. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment.

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in portions of Wisconsin, Michigan, Minnesota and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 145,000 retail customers. Minnesota Power also has 16 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a wholesale customer of Minnesota Power. SWL&P provides regulated utility electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 13,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities . (See Note 4. Regulatory Matters.)

ALLETE Clean Energy focuses on developing, acquiring, and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates, in four states, approximately 535 MW of nameplate capacity wind energy generation that is contracted under PSAs of various durations. ALLETE Clean Energy also engages in the development of wind energy facilities to operate under long-term PSAs or for sale to others upon completion.

U.S. Water Services provides integrated water management for industry by combining chemical, equipment, engineering and service for customized solutions to reduce water and energy usage, and improve efficiency.

Corporate and Other is comprised of BNI Energy, our coal mining operations in North Dakota, ALLETE Properties, our legacy Florida real estate investment, other business development and corporate expenditures, unallocated interest expense, a small amount of non-rate base generation, approximately 5,000 acres of land in Minnesota, and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2017 , unless otherwise indicated. All subsidiaries are wholly-owned unless otherwise specifically indicated. References in this report to “we,” “us” and “our” are to ALLETE and its subsidiaries, collectively.

2017 Financial Overview

The following net income discussion summarizes a comparison of the year ended December 31, 2017 , to the year ended December 31, 2016 .

Net income attributable to ALLETE in 2017 was $172.2 million , or $3.38 per diluted share, compared to $155.3 million , or $3.14 per diluted share, in 2016 . Net income in 2017 included the favorable impacts of $13.0 million after-tax, or $0.25 per share, for the remeasurement of deferred income tax assets and liabilities resulting from the TCJA (see Note 1. Operations and Significant Accounting Policies) and $7.9 million after-tax, or $0.16 per share, related to the regulatory outcome of the MPUC’s modification of its November 2016 order on the allocation of North Dakota investment tax credits. Net income in 2017 also included a non-cash $11.4 million after-tax charge, or $0.22 per share, for the MPUC’s decision in Minnesota Power’s 2016 general rate case at a hearing on January 18, 2018, disallowing recovery of Minnesota Power’s regulatory asset for deferred fuel adjustment clause costs due to the anticipated adoption of a forward-looking fuel adjustment clause methodology. (See Note 4. Regulatory Matters.) Net income in 2016 included the favorable impact related to the change in fair value of the contingent consideration liability of $13.6 million after-tax, or $0.28 per share. Net income in 2016 also included an adverse impact of $8.8 million after-tax, or $0.18 per share, for the regulatory outcome of the November 2016 MPUC order on the allocation of North Dakota investment tax credits, a $3.3 million after-tax, or $0.07 per share, goodwill impairment charge and a $0.9 million after-tax expense, or $0.02 per share, related to the repayment of long-term debt at ALLETE Clean Energy. Earnings per share dilution in 2017 was $0.11 due to additional shares of common stock outstanding as of December 31, 2017 .

2017 Financial Overview (Continued)

Regulated Operations net income attributable to ALLETE was $128.4 million in 2017 , compared to $135.5 million in 2016 . Net income in 2017 at Minnesota Power decreased $9.8 million after-tax reflecting a non-cash $11.4 million after-tax charge for the MPUC's decision disallowing the recovery of Minnesota Power's regulatory asset for deferred fuel adjustment clause costs due to the anticipated adoption of a forward-looking fuel adjustment clause methodology. In addition, net income decreased due to lower kWh sales to other power suppliers as a result of higher industrial sales coupled with lower market prices, higher interest and taxes other than income taxes, and lower kWh sales to residential, commercial and municipal customers due to milder temperatures in 2017. These decreases were partially offset by lower depreciation expense of $14.6 million after-tax resulting from the MPUC's decision to modify the depreciable lives at Boswell, and higher industrial kWh sales. Interim retail rate refund reserves fully offset the interim retail rates recognized during 2017 due to the regulatory outcome of the MPUC's decisions in Minnesota Power's 2016 general rate case on January 18, 2018. Our equity earnings in ATC for 2017 increased $2.6 million after-tax primarily due to additional investments in ATC and period over period changes in ATC's estimate of a refund liability related to MISO return on equity complaints.

ALLETE Clean Energy net income attributable to ALLETE was $41.5 million in 2017 compared to $13.4 million in 2016 . Net income in 2017 reflected a $23.6 million after-tax benefit due to the remeasurement of deferred income tax assets and liabilities resulting from the TCJA, increased production tax credits due to the requalification of WTGs for production tax credits at its Storm Lake I, Storm Lake II and Lake Benton wind energy facilities, lower operating and maintenance expenses, and lower interest expense compared to 2016. Net income in 2016 included a $3.3 million after-tax goodwill impairment charge and a $0.9 million after-tax expense related to the repayment of long-term debt. Net income in 2016 also included an allocation of earnings to a non-controlling interest in the limited liability company that owns the Condon wind energy facility, which was acquired by ALLETE Clean Energy in April 2016. (See Note 6. Acquisitions.)

U.S. Water Services net income attributable to ALLETE was $10.7 million in 2017 , compared to $1.5 million in 2016 . Net income in 2017 reflected a $9.2 million after-tax benefit due to the remeasurement of deferred income tax assets and liabilities resulting from the TCJA, and higher operating revenue, partially offset by increased operating expenses as a result of investments for future growth in waste treatment and water safety applications. Net income in 2017 also included a net loss of $0.8 million primarily for transaction fees and amortization expense of the Tonka Water acquisition on September 1, 2017. (See Note 6. Acquisitions.)

Corporate and Other net loss attributable to ALLETE was $8.4 million in 2017 , compared to net income of $4.9 million in 2016 . The net loss in 2017 included additional income tax expense of $19.8 million after-tax for the remeasurement of deferred income tax assets and liabilities resulting from the TCJA. The net loss in 2017 also included a $7.9 million after-tax favorable impact for the regulatory outcome of the MPUC's modification of its November 2016 order on the allocation of North Dakota investment tax credits, lower accretion expense relating to the contingent consideration liability, and lower interest expense. Net income in 2016 included an after-tax gain of $13.6 million related to the change in fair value of the contingent consideration liability, partially offset by an $8.8 million after-tax adverse impact for the regulatory outcome of the November 2016 MPUC order.

2017 Compared to 2016

(See Note 17. Business Segments for financial results by segment.)

Regulated Operations

Year Ended December 31	2017	2016
Millions		
Operating Revenue – Utility	$1,063.8	$1,000.7
Fuel, Purchased Power and Gas – Utility	396.9	339.9
Transmission Services – Utility	71.2	65.2
Operating and Maintenance	223.1	220.7
Depreciation and Amortization	132.6	154.3
Taxes Other than Income Taxes	51.1	47.7
Operating Income	188.9	172.9
Interest Expense	(57.0)	(52.1)
Equity Earnings in ATC	22.5	18.5
Other Income	1.2	2.1
Income Before Income Taxes	155.6	141.4
Income Tax Expense	27.2	5.9
Net Income Attributable to ALLETE	$128.4	$135.5

Operating Revenue – Utility increased $63.1 million , or 6 percent , from 2016 primarily due to the period over period impact of the regulatory outcomes related to the allocation of North Dakota investment tax credits, as well as higher fuel adjustment clause recoveries, conservation improvement program recoveries and revenue from kWh sales, partially offset by lower FERC formula-based rates, financial incentives under the conservation improvement program and transmission revenue. Interim retail rate refund reserves fully offset the interim retail rates recognized during 2017.

Revenue increased $29.3 million due to the period over period impact of the regulatory outcomes related to the allocation of North Dakota investment tax credits. As a result of the favorable impact for the regulatory outcome of the MPUC's modification of its November 2016 order on the allocation of North Dakota investment tax credits, operating revenue increased approximately $14 million in 2017. In 2016, operating revenue decreased approximately $15 million as a result of the adverse impact for the regulatory outcome of the November 2016 MPUC order. (See Note 4. Regulatory Matters.)

Fuel adjustment clause recoveries increased $24.4 million due to higher fuel and purchased power costs attributable to retail and municipal customers. (See *Operating Expenses - Fuel, Purchased Power and Gas – Utility.*)

Conservation improvement program recoveries increased $7.2 million from 2016 primarily due to an increase in related expenditures. (See *Operating Expenses - Operating and Maintenance.*)

Revenue from kWh sales increased $3.9 million from 2016 primarily due to higher sales to Industrial customers. Sales to Industrial customers increased 13.5 percent primarily due to increased taconite production and the commencement of a long-term PSA with Silver Bay Power in June 2016. Sales to Other Power Suppliers decreased 6.4 percent from 2016 as a result of increased sales to Industrial customers. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations; market prices were lower in 2017 compared to 2016. Sales to Residential, Commercial and Municipal customers decreased primarily due to milder temperatures in 2017.

2017 Compared to 2016 (Continued)
Regulated Operations (Continued)

Kilowatt-hours Sold	2017	2016	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipal				
Residential	1,096	1,102	(6)	(0.5)
Commercial	1,420	1,442	(22)	(1.5)
Industrial	7,327	6,456	871	13.5
Municipal	799	816	(17)	(2.1)
Total Retail and Municipal	10,642	9,816	826	8.4
Other Power Suppliers	4,039	4,316	(277)	(6.4)
Total Regulated Utility Kilowatt-hours Sold	14,681	14,132	549	3.9

Revenue from electric sales to taconite and iron concentrate customers accounted for 22 percent of consolidated operating revenue in 2017 (18 percent in 2016). Revenue from electric sales to paper, pulp and secondary wood product customers accounted for 5 percent of consolidated operating revenue in 2017 (6 percent in 2016). Revenue from electric sales to pipelines and other industrial customers accounted for 7 percent of consolidated operating revenue in 2017 (7 percent in 2016).

Interim retail rates for Minnesota Power were approved by the MPUC and became effective January 1, 2017. Interim retail rate refund reserves of $31.6 million fully offset the interim retail rates recognized during 2017 due to the regulatory outcome of the MPUC's decision in Minnesota Power's 2016 general rate case on January 18, 2018. (See Note 4. Regulatory Matters.)

Revenue from wholesale customers under FERC formula-based rates decreased $4.9 million from 2016 primarily due to lower rates.

Financial incentives under the conservation improvement program decreased $1.9 million from 2016 .

Transmission revenue decreased $1.7 million primarily due to lower MISO-related revenue, partially offset by period over period changes in the estimate of a refund liability related to MISO return on equity complaints. (See *Operating Expenses - Transmission Services – Utility.*)

Operating Expenses increased $47.1 million , or 6 percent , from 2016 .

Fuel, Purchased Power and Gas – Utility expense increased $57.0 million , or 17 percent , from 2016 primarily due to increased kWh sales, higher fuel costs and a $19.5 million expense for the MPUC's decision disallowing recovery of Minnesota Power's regulatory asset for deferred fuel adjustment clause costs at a hearing on January 18, 2018, due to the anticipated adoption of a forward-looking fuel adjustment clause methodology. These increases were partially offset by lower purchased power prices. Fuel and purchased power expense related to our retail and municipal customers is recovered through the fuel adjustment clause. (See *Operating Revenue – Utility.*)

Transmission Services – Utility expense increased $6.0 million , or 9 percent , from 2016 primarily due to higher MISO-related expense. (See *Operating Revenue – Utility.*)

Operating and Maintenance expense increased $2.4 million , or 1 percent , from 2016 primarily due to a $7.2 million increase in conservation improvement program expenses in 2017. Conservation improvement program expenses are recovered from certain retail customers. (See *Operating Revenue – Utility.*) This increase was partially offset by lower materials purchased for generation facilities. Operating and Maintenance expense in 2016 included a $3.6 million sales tax refund, partially offset by higher storm restoration costs of $2.9 million related to severe wind storms across Minnesota Power's service territory in July 2016.

2017 Compared to 2016 (Continued)
Regulated Operations (Continued)

Depreciation and Amortization expense decreased $21.7 million , or 14 percent , from 2016 primarily due to modifications of the depreciable lives for Boswell, partially offset by additional property, plant and equipment in service. At a hearing on January 18, 2018, the MPUC decided to extend the depreciable lives of Boswell Unit 3, Unit 4 and common facilities to 2050, and shorten the depreciable lives of Boswell Unit 1 and Unit 2 to 2022, resulting in a net decrease to depreciation expense of approximately $25 million in 2017.

Taxes Other than Income Taxes increased $3.4 million , or 7 percent , from 2016 primarily due to higher property tax expenses resulting from higher taxable plant.

Interest Expense increased $4.9 million , or 9 percent , from 2016 primarily due to higher average interest rates. We record interest expense for Regulated Operations primarily based on rate base and authorized capital structure, and allocate the balance to Corporate and Other.

Equity Earnings in ATC increased $4.0 million , or 22 percent , from 2016 primarily due to additional investments in ATC and period over period changes in ATC's estimate of a refund liability related to MISO return on equity complaints. (See Note 5. Investment in ATC.)

Income Tax Expense increased $21.3 million from 2016 primarily due to the period over period impact of the regulatory outcomes related to the allocation of North Dakota investment tax credits and higher pre-tax income. The TCJA did not have an impact on income tax expense for our Regulated Operations as the remeasurement of deferred income tax assets and liabilities primarily resulted in the recording of regulatory assets and liabilities.

In 2017, as a result of the favorable impact for the regulatory outcome of the MPUC's modification of its November 2016 order on the allocation of North Dakota investment tax credits, Regulated Operations increased operating revenue and reduced the corresponding regulatory liability by approximately $14 million resulting in an income tax expense of $6.1 million. In addition, Regulated Operations recorded an income tax expense of $7.9 million for North Dakota investment tax credits transferred to Corporate and Other, resulting in no impact to net income for Regulated Operations. Corporate and Other recorded an offsetting income tax benefit of $7.9 million for the North Dakota investment tax credits transferred from Regulated Operations.

In 2016, as a result of the adverse impact for the regulatory outcome of the November 2016 MPUC order, Regulated Operations reduced operating revenue and recorded a corresponding regulatory liability for approximately $15 million resulting in an income tax benefit of $6.2 million. In addition, Regulated Operations recorded an income tax benefit of $8.8 million for North Dakota investment tax credits transferred from Corporate and Other, resulting in no impact to net income for Regulated Operations. Corporate and Other recorded an offsetting income tax expense of $8.8 million for the North Dakota investment tax credits transferred to Regulated Operations.

ALLETE Clean Energy

Year Ended December 31	2017	2016
Millions		
Operating Revenue	$80.5	$80.5
Net Income Attributable to ALLETE *(a)*	$41.5	$13.4

(a) Results in 2017 include a $23.6 million after-tax benefit due to the remeasurement of deferred income tax assets and liabilities resulting from the TCJA.

Operating Revenue is consistent with 2016 as lower kWh sales at the wind energy facilities resulting from lower wind resources were offset by higher amortization of PSAs. (See Note 1. Operations and Significant Accounting Policies.)

2017 Compared to 2016 (Continued)
ALLETE Clean Energy (Continued)

	Year Ended December 31,			
	2017		2016	
Production and Operating Revenue	**kWh**	**Revenue**	**kWh**	**Revenue**
Millions				
Wind Energy Facility				
Lake Benton	241.8	$12.3	254.7	$12.8
Storm Lake II	152.6	10.0	154.8	10.1
Condon	90.7	7.5	96.9	8.2
Storm Lake I	215.6	12.4	222.3	11.6
Chanarambie/Viking	263.5	13.9	278.8	13.4
Armenia Mountain	267.4	24.4	268.2	24.4
Total Production and Operating Revenue	1,231.6	$80.5	1,275.7	$80.5

Net Income Attributable to ALLETE increased $28.1 million from 2016 . Net income in 2017 included a $23.6 million after-tax benefit due to the remeasurement of deferred income tax assets and liabilities resulting from the TCJA, increased production tax credits due to the requalification of WTGs at ALLETE Clean Energy's Storm Lake I, Storm Lake II and Lake Benton wind energy facilities, lower operating and maintenance expense, and lower interest expense compared to 2016. Net income in 2016 included a $3.3 million after-tax goodwill impairment charge and a $0.9 million after-tax expense related to the repayment of long-term debt. Net income in 2016 also included an allocation of earnings to a non-controlling interest in the limited liability company that owns the Condon wind energy facility, which was acquired by ALLETE Clean Energy in April 2016. (See Note 6. Acquisitions.)

U.S. Water Services

Year Ended December 31	**2017**	**2016**
Millions		
Operating Revenue	$151.8	$137.5
Net Income Attributable to ALLETE *(a)*	$10.7	$1.5

(a) Results in 2017 include a $9.2 million after-tax benefit due to the remeasurement of deferred income tax assets and liabilities resulting from the TCJA.

Operating Revenue increased $14.3 million from 2016 primarily due to the acquisitions of WEST in October 2016 and Tonka Water in September 2017. (See Note 6. Acquisitions.) Revenue from chemical sales and related services was $116.0 million in 2017 compared to $110.5 million in 2016. Revenue from equipment sales was $35.8 million for 2017 compared to $27.0 million in 2016; equipment sales can significantly fluctuate from period to period.

Net Income Attributable to ALLETE increased $9.2 million from 2016 . Net income in 2017 included a $9.2 million after-tax benefit due to the remeasurement of deferred income tax assets and liabilities resulting from the TCJA, and higher operating revenue, partially offset by increased operating expenses as a result of investments for future growth in waste treatment and water safety applications. Net income in 2017 also included a net loss of $0.8 million primarily for transaction fees and amortization expense of the Tonka Water acquisition on September 1, 2017. (See Note 6. Acquisitions.)

Cash flow from operations for U.S. Water Services was approximately $12 million in 2017 compared to approximately $11 million in 2016.

Corporate and Other

Operating Revenue increased $2.2 million , or 2 percent , from 2016 primarily due to an increase in revenue at BNI Energy, which operates under cost-plus fixed fee contracts, as a result of higher expenses and record coal sales in 2017, partially offset by a decrease in land sales at ALLETE Properties. Operating revenue in 2016 included the sale of ALLETE Properties' Ormond Crossings project and Lake Swamp wetland mitigation bank for approximately $21 million.

2017 Compared to 2016 (Continued)
Corporate and Other (Continued)

Net Loss Attributable to ALLETE was $8.4 million in 2017 compared to net income of $4.9 million in 2016 . The net loss in 2017 included a $19.8 million after-tax expense due to the remeasurement of deferred income tax assets and liabilities resulting from the TCJA. The net loss in 2017 also included a $7.9 million after-tax favorable impact for the regulatory outcome of the MPUC's modification of its November 2016 order on the allocation of North Dakota investment tax credits, lower accretion expense relating to the contingent consideration liability, and lower interest expense. Net income in 2016 included an after-tax gain of $13.6 million related to the change in fair value of the contingent consideration liability, partially offset by an $8.8 million after-tax adverse impact for the regulatory outcome of the November 2016 MPUC order.

Net income at BNI Energy was $4.5 million in 2017 which included a $3.1 million after-tax expense due to the remeasurement of deferred income tax assets and liabilities resulting from the TCJA, partially offset by more tons sold; net income in 2016 was $6.8 million. The net loss at ALLETE Properties was $8.8 million in 2017 which included a $7.8 million after-tax expense for the remeasurement of deferred income tax assets and liabilities resulting from the TCJA; net income in 2016 was $0.7 million.

Income Taxes – Consolidated

For the year ended December 31, 2017 , the effective tax rate was 7.9 percent (11.3 percent for the year ended December 31, 2016). The decrease from 2016 was primarily due to the remeasurement of deferred income tax assets and liabilities resulting from the TCJA and increased production tax credits, partially offset by higher pre-tax income. (See *Regulated Operations - Income Tax Expense* .) The effective rate deviated from the combined statutory rate of approximately 41 percent primarily due to the remeasurement of deferred income tax assets and liabilities resulting from the TCJA, and production tax credits. (See Note 13. Income Tax Expense.)

2016 Compared to 2015

(See Note 17. Business Segments for financial results by segment.)

Regulated Operations

Year Ended December 31	2016	2015
Millions		
Operating Revenue – Utility	$1,000.7	$991.2
Fuel, Purchased Power and Gas – Utility	339.9	336.0
Transmission Services – Utility	65.2	54.1
Operating and Maintenance	220.7	229.6
Depreciation and Amortization	154.3	135.1
Taxes Other than Income Taxes	47.7	46.2
Operating Income	172.9	190.2
Interest Expense	(52.1)	(53.9)
Equity Earnings in ATC	18.5	16.3
Other Income	2.1	3.4
Income Before Income Taxes	141.4	156.0
Income Tax Expense	5.9	24.4
Net Income Attributable to ALLETE	$135.5	$131.6

Operating Revenue – Utility increased $ 9.5 million , or 1 percent , from 2015 primarily due to higher transmission revenue, cost recovery rider revenue, pricing on PSAs with Other Power Suppliers and FERC formula-based rates, partially offset by the adverse impact for the regulatory outcome of the November 2016 MPUC order related to the allocation of North Dakota investment tax credits as well as lower conservation improvement program recoveries.

Transmission revenue increased $9.7 million primarily due to period over period changes in our estimate of a refund liability related to MISO return on equity complaints and higher MISO-related revenue. (See *Operating Expenses - Transmission Services – Utility.*)

2016 Compared to 2015 (Continued)
Regulated Operations (Continued)

Cost recovery rider revenue increased $7.5 million primarily due to the completion of the Boswell Unit 4 environmental upgrade in the fourth quarter of 2015.

Despite lower kWh sales, revenue increased $4.9 million from 2015 primarily due to higher pricing on PSAs with Other Power Suppliers in 2016. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations. Sales to industrial customers decreased 2.7 percent primarily due to reduced taconite production. In addition, demand revenue from industrial customers was down in 2016 as a result of lower demand nominations.

Kilowatt-hours Sold	2016	2015	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipal				
Residential	1,102	1,113	(11)	(1.0)
Commercial	1,442	1,462	(20)	(1.4)
Industrial	6,456	6,635	(179)	(2.7)
Municipal	816	833	(17)	(2.0)
Total Retail and Municipal	9,816	10,043	(227)	(2.3)
Other Power Suppliers	4,316	4,310	6	0.1
Total Regulated Utility Kilowatt-hours Sold	14,132	14,353	(221)	(1.5)

Revenue from electric sales to taconite and iron concentrate customers accounted for 18 percent of consolidated operating revenue in 2016 (17 percent in 2015). Revenue from electric sales to paper, pulp and secondary wood product customers accounted for 6 percent of consolidated operating revenue in 2016 (6 percent in 2015). Revenue from electric sales to pipelines and other industrial customers accounted for 7 percent of consolidated operating revenue in 2016 (6 percent in 2015).

Revenue from wholesale customers under FERC formula-based rates increased $3.8 million primarily due to additional environmental and other investments.

Revenue decreased $15.0 million due to the adverse impact for the regulatory outcome of the November 2016 MPUC order related to the allocation of North Dakota investment tax credits. (See Note 4. Regulatory Matters.)

Conservation improvement program recoveries decreased $4.1 million from 2015 primarily due to a reduction in related expenditures. (See *Operating Expenses - Operating and Maintenance Expense.*)

Operating Expenses increased $26.8 million , or 3 percent , from 2015 .

Fuel, Purchased Power and Gas – Utility expense increased $3.9 million , or 1 percent , from 2015 primarily due to higher fuel and purchased power prices in 2016 compared to 2015, partially offset by lower kWh sales in 2016. Fuel and purchased power expense related to retail and municipal customers is recovered through the fuel adjustment clause.

Transmission Services – Utility expense increased $11.1 million , or 21 percent , from 2015 primarily due to higher MISO-related expense and period over period changes in our estimate of a refund for MISO transmission expense related to MISO return on equity complaints. (See *Operating Revenue* and Note 4. Regulatory Matters.)

Operating and Maintenance expense decreased $8.9 million , or 4 percent , from 2015 , primarily due to lower pension and other postretirement benefit expenses (see Note 15. Pension and Other Postretirement Benefit Plans), a $3.6 million sales tax refund received in 2016 and a $4.1 million decrease in conservation improvement program expenses. Conservation improvement program expenses are recovered from certain retail customers. (See *Operating Revenue.*) Operating and Maintenance expense included higher storm restoration costs of $2.9 million related to severe wind storms across Minnesota Power's service territory in July 2016.

2016 Compared to 2015 (Continued)
Regulated Operations (Continued)

Depreciation and Amortization expense increased $19.2 million , or 14 percent , from 2015 primarily due to additional property, plant and equipment in service.

Taxes Other than Income Taxes increased $1.5 million , or 3 percent , from 2015 primarily due to higher property tax expenses resulting from higher taxable plant.

Interest Expense decreased $1.8 million , or 3 percent , from 2015 primarily due to lower average interest rates. We record interest expense for Regulated Operations based on Minnesota Power's rate base and authorized capital structure, and allocate the balance to Corporate and Other.

Equity Earnings in ATC increased $2.2 million , or 13 percent , from 2015 primarily due to additional investments in ATC and period over period changes in ATC's estimate of a refund liability related to MISO return on equity complaints.

Other Income decreased $1.3 million , or 38 percent , from 2015 primarily due to lower AFUDC–Equity.

Income Tax Expense decreased $18.5 million , or 76 percent , from 2015 due to lower pre-tax income, higher production tax credits and the adverse impact for the regulatory outcome of the November 2016 MPUC order related to the allocation of North Dakota investment tax credits. (See Note 4. Regulatory Matters.)

As a result of the adverse impact for the regulatory outcome of the November 2016 MPUC order, Regulated Operations reduced operating revenue and recorded a corresponding regulatory liability for approximately $15 million resulting in an income tax benefit of $6.2 million in 2016. In addition, Regulated Operations recorded an income tax benefit of $8.8 million for North Dakota investment tax credits transferred from Corporate and Other, resulting in no impact to net income for Regulated Operations. Corporate and Other recorded an offsetting income tax expense of $8.8 million for the North Dakota investment tax credits transferred to Regulated Operations.

ALLETE Clean Energy

Year Ended December 31,	2016	2015
Millions		
Operating Revenue	$80.5	$262.1
Net Income Attributable to ALLETE	$13.4	$29.9

Operating Revenue decreased $181.6 million from 2015 . Operating revenue in 2015 included the recognition of $197.7 million in revenue for the construction of a wind energy facility sold to Montana-Dakota Utilities in 2015. Operating revenue in 2016 was positively impacted by additional revenue generated from the operations of wind energy facilities acquired in April and July 2015.

	Year Ended December 31,			
	2016		2015	
Production and Operating Revenue	**kWh**	**Revenue**	**kWh**	**Revenue**
Millions				
Wind Energy Facility				
Lake Benton	254.7	$12.8	265.1	$13.5
Storm Lake II	154.8	10.1	186.4	11.7
Condon	96.9	8.2	84.1	7.8
Storm Lake I	222.3	11.6	230.7	12.1
Chanarambie/Viking	278.8	13.4	199.1	9.8
Armenia Mountain	268.2	24.4	111.6	9.5
Total Wind Energy Facilities	1,275.7	80.5	1,077.0	64.4
Development Fee *(a)*	—	—	—	197.7
Total Production and Operating Revenue	1,275.7	$80.5	1,077.0	$262.1

(a) 2015 included the recognition of $162.9 million of cost of sales.

2016 Compared to 2015 (Continued)
ALLETE Clean Energy (Continued)

Net Income Attributable to ALLETE decreased $16.5 million from 2015 . Net income for 2015 included the recognition of profit of $20.4 million after-tax for the construction of a wind energy facility sold to Montana-Dakota Utilities. In 2015, net income also included $1.8 million after-tax expense in acquisition costs related to the Chanarambie/Viking and Armenia Mountain wind energy facilities. Net income in 2016 included a $3.3 million after-tax non-cash goodwill impairment charge (see Note 1. Operations and Significant Accounting Policies) and a $0.9 million after-tax expense related to the repayment of long-term debt. Earnings in 2016 were positively impacted by income generated from the operations of wind energy facilities acquired in April and July 2015.

U.S. Water Services

	Year Ended December 31, 2016	Period February 10, 2015 Through December 31, 2015
Millions		
Operating Revenue	$137.5	$119.8
Net Income Attributable to ALLETE	$1.5	$0.9

Operating Revenue increased $17.7 million in 2016 compared to the period from February 10, 2015, to December 31, 2015 . The results for 2015 reflect operations from the date of acquisition, February 10, 2015, through December 31, 2015 , and therefore, do not reflect a full year. Revenue from chemical sales and related services was $110.5 million in 2016 compared to $92.5 million in 2015. Revenue from equipment sales was $27.0 million for 2016 compared to $27.3 million in 2015; equipment sales can significantly fluctuate from period to period.

Net Income Attributable to ALLETE increased $0.6 million in 2016 compared to the period from February 10, 2015, to December 31, 2015 . The results for 2015 reflect operations from the date of acquisition, February 10, 2015, through December 31, 2015 , and therefore do not reflect a full year. Net income in 2015 included an additional $1.9 million of after-tax expense recognized as cost of sales related to purchase accounting for inventories and sales backlog which have been fully recognized as of December 31, 2016. Earnings in 2016 reflected increased investments in back office systems and support at U.S. Water Services as we create a platform for future growth.

Corporate and Other

Operating Revenue increased $7.7 million , or 7 percent , from 2015 primarily due to an increase in land sales at ALLETE Properties, which sold its Ormond Crossings project and Lake Swamp wetland mitigation bank in 2016. The increase was partially offset by a decrease in revenue at BNI Energy, which operates under cost-plus fixed fee contracts, as a result of lower expenses and fewer tons sold in 2016 compared to 2015.

Net Income Attributable to ALLETE increased $26.2 million from 2015 . Net income in 2016 included an after-tax gain of $13.6 million related to the change in fair value of the U.S. Water Services contingent consideration liability and increased land sales at ALLETE Properties, partially offset by an adverse impact of $8.8 million after-tax for the regulatory outcome of the November 2016 MPUC order. (*Regulated Operations - Income Tax Expense.*) In 2015, the net loss included a $22.3 million after-tax non-cash impairment charge relating to the real estate assets of ALLETE Properties and $3.0 million after-tax expense in acquisition costs related to U.S. Water Services. Net income at BNI Energy increased to $6.8 million in 2016 compared to $6.7 million in 2015, and net income at ALLETE Properties increased to $0.7 million in 2016 compared to a net loss of $23.3 million in 2015.

Income Taxes – Consolidated

For the year ended December 31, 2016 , the effective tax rate was 15.2 percent (22.6 percent for the year ended December 31, 2015). The decrease from the year ended December 31, 2015, was primarily due to increased production tax credits in 2016 related to additional wind energy generation. The effective rate deviated from the combined statutory rate of approximately 41 percent primarily due to production tax credits. (See Note 13. Income Tax Expense.)

Critical Accounting Policies

The preparation of financial statements and related disclosures in conformity with GAAP requires management to make various estimates and assumptions that affect amounts reported in the Consolidated Financial Statements. These estimates and assumptions may be revised, which may have a material effect on the Consolidated Financial Statements. Actual results may differ from these estimates and assumptions. These policies are discussed with the Audit Committee of our Board of Directors on a regular basis. We believe the following policies are most critical to our business and the understanding of our results of operations.

Regulatory Accounting. Our regulated utility operations are accounted for in accordance with the accounting standards for the effects of certain types of regulation. These standards require us to reflect the effect of regulatory decisions in our financial statements. Regulatory assets represent incurred costs that have been deferred as they are probable for recovery in customer rates. Regulatory liabilities represent obligations to make refunds to customers and amounts collected in rates for which the related costs have not yet been incurred. The Company assesses quarterly whether regulatory assets and liabilities meet the criteria for probability of future recovery or deferral. This assessment considers factors such as, but not limited to, changes in the regulatory environment and recent rate orders to other regulated entities under the same jurisdiction. If future recovery or refund of costs becomes no longer probable, the assets and liabilities would be recognized in current period net income or other comprehensive income. (See Note 4. Regulatory Matters.)

Pension and Postretirement Health and Life Actuarial Assumptions. We account for our pension and other postretirement benefit obligations in accordance with the accounting standards for defined benefit pension and other postretirement plans. These standards require the use of several important assumptions, including the expected long-term rate of return on plan assets, the discount rate and mortality assumptions, among others, in determining our obligations and the annual cost of our pension and other postretirement benefits. In establishing the expected long-term rate of return on plan assets, we determine the long-term historical performance of each asset class and adjust these for current economic conditions while utilizing the target allocation of our plan assets to forecast the expected long-term rate of return. Our pension asset allocation as of December 31, 2017 , was approximately 53 percent equity securities, 38 percent debt, 5 percent private equity and 4 percent real estate. Our postretirement health and life asset allocation as of December 31, 2017 , was approximately 64 percent equity securities, 31 percent debt and 5 percent private equity. Equity securities consist of a mix of market capitalization sizes with domestic and international securities. In 2017 , we used expected long-term rates of return of 7.50 percent in our actuarial determination of our pension expense and 6.00 percent to 7.50 percent in our actuarial determination of our other postretirement expense. The actuarial determination uses an asset smoothing methodology for actual returns to reduce the volatility of varying investment performance over time. We review our expected long-term rate of return assumption annually and will adjust it to respond to changing market conditions. A one-quarter percent decrease in the expected long-term rate of return would increase the annual expense for pension and other postretirement benefits by approximately $1.8 million , pre-tax.

The discount rate is computed using a bond matching study which utilizes a portfolio of high quality bonds that produce cash flows similar to the projected costs of our pension and other postretirement plans. In 2017 , we used discount rates of 4.53 percent and 4.57 percent in our actuarial determination of our pension and other postretirement expense, respectively. We review our discount rates annually and will adjust them to respond to changing market conditions. A one-quarter percent decrease in the discount rate would increase the annual expense for pension and other postretirement benefits by approximately $1.1 million , pre-tax.

The mortality assumptions used to calculate our pension and other postretirement benefit obligations as of December 31, 2017 , considered a modified RP-2014 mortality table and mortality projection scale. (See Note 15. Pension and Other Postretirement Benefit Plans.)

Impairment of Long-Lived Assets. We review our long-lived assets, which include the legacy real estate assets of ALLETE Properties, for indicators of impairment in accordance with the accounting standards for property, plant and equipment on a quarterly basis.

In accordance with the accounting standards for property, plant and equipment, if indicators of impairment exist, we test our long-lived assets for recoverability by comparing the carrying amount of the asset to the undiscounted future net cash flows expected to be generated by the asset. Cash flows are assessed at the lowest level of identifiable cash flows. The undiscounted future net cash flows are impacted by trends and factors known to us at the time they are calculated and our expectations related to: management’s best estimate of future sales prices; holding period and timing of sales; method of disposition; and future expenditures necessary to maintain the operations.

Critical Accounting Policies (Continued)

Taxation. We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income taxes and taxes other than income taxes. Judgments related to income taxes require the recognition in our financial statements of the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained on audit. Tax positions that do not meet the "more-likely-than-not" criteria are reflected as a tax liability in accordance with the accounting standards for uncertainty in income taxes. We record a valuation allowance against our deferred tax assets to the extent it is more-likely-than-not that some portion or all of the deferred tax assets will not be realized.

We are subject to income taxes in various jurisdictions. We make assumptions and judgments each reporting period to estimate our income tax assets, liabilities, benefits and expenses. Judgments and assumptions are supported by historical data and reasonable projections. Our assumptions and judgments include the application of tax statutes and regulations, and projections of future federal taxable income, state taxable income, and state apportionment to determine our ability to utilize NOL and credit carryforwards prior to their expiration. Significant changes in assumptions regarding future federal and state taxable income or a change in tax rates could require new or increased valuation allowances which could result in a material impact on our results of operations.

Valuation of Goodwill and Intangible Assets. When we acquire a business, the assets acquired and liabilities assumed are recorded at their respective fair values as of the acquisition date. Determining the fair value of intangible assets acquired as part of a business combination requires us to make significant estimates. These estimates include the amount and timing of projected future cash flows, the discount rate used to discount those cash flows to present value, the assessment of the asset's life cycle, and the consideration of legal, technical, regulatory, economic and competitive risks. The fair value assigned to intangible assets is determined by estimating the future cash flows of each project and discounting the net cash flows back to their present values. The discount rate used is determined at the time of measurement in accordance with accepted valuation standards.

Goodwill. Goodwill is the excess of the purchase price (consideration transferred) over the estimated fair value of net assets of acquired businesses. In accordance with GAAP, goodwill is not amortized. The Company assesses whether there has been an impairment of goodwill annually in the fourth quarter and whenever an event occurs or circumstances change that would indicate the carrying amount may be impaired. Impairment testing for goodwill is done at the reporting unit level. An impairment loss is recognized when the carrying amount of the reporting unit's net assets exceeds the estimated fair value of the reporting unit. The test for impairment requires us to make several estimates about fair value, most of which are based on projected future cash flows. Our estimates associated with the goodwill impairment test are considered critical due to the amount of goodwill recorded on our Consolidated Balance Sheet and the judgment required in determining fair value, including projected future cash flows. The results of our annual impairment test are discussed in Note 1. Operations and Significant Accounting Policies and Note 9. Fair Value in this Form 10-K. Goodwill was $148.3 million and $131.2 million as of December 31, 2017 , and December 31, 2016 , respectively.

Intangible Assets. Intangible assets include customer relationships, patents, non-compete agreements, land easements, trademarks and trade names. Intangible assets with definite lives consist of customer relationships, which are amortized using an attrition model, and patents, non-compete agreements, land easements and certain trade names, which are amortized on a straight-line basis with estimated useful lives ranging from approximately 1 year to approximately 20 years. We review definite-lived intangible assets for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Indefinite-lived intangible assets consist of trademarks and certain trade names, which are tested for impairment annually in the fourth quarter and whenever an event occurs or circumstances change that would indicate that the carrying amount may be impaired. Impairment is calculated as the excess of the asset's carrying amount over its fair value. Our impairment reviews are based on an estimated future cash flow approach that requires significant judgment with respect to future revenue and expense growth rates, selection of an appropriate discount rate, and other assumptions and estimates. We use estimates that are consistent with our business plans and a market participant view of the assets being evaluated. The results of our annual impairment test are discussed in Note 9. Fair Value in this Form 10-K. Intangible assets, net of accumulated amortization, were $77.6 million and $82.2 million as of December 31, 2017 , and December 31, 2016 , respectively.

Outlook

ALLETE is an energy company committed to earning a financial return that rewards our shareholders, allows for reinvestment in our businesses and sustains growth. The Company has long-term objectives of achieving average annual earnings per share growth of 5 percent to 7 percent, and providing a dividend payout competitive with our industry.

ALLETE is predominately a regulated utility through Minnesota Power, SWL&P and an investment in ATC. ALLETE's strategy is to remain predominately a regulated utility while investing in its Energy Infrastructure and Related Services businesses to complement its regulated businesses, balance exposure to the utility's industrial customers and provide potential long-term earnings growth. ALLETE expects net income from Regulated Operations to be approximately 80 percent of total consolidated net income in 2018 . Over the next several years, the contribution of the Energy Infrastructure and Related Services businesses to net income is expected to increase as ALLETE grows these operations. ALLETE expects its businesses to provide regulated, contracted or recurring revenues, and to support sustained growth in net income and cash flow.

Regulated Operations. Minnesota Power's long-term strategy is to be the leading electric energy provider in northeastern Minnesota by providing safe, reliable and cost-competitive electric energy, while complying with environmental permit conditions and renewable energy requirements. Keeping the cost of energy production competitive enables Minnesota Power to effectively compete in the wholesale power markets and minimizes retail rate increases to help maintain customer viability. As part of maintaining cost competitiveness, Minnesota Power intends to reduce its exposure to possible future carbon and GHG legislation by reshaping its generation portfolio, over time, to reduce its reliance on coal. (See *EnergyForward.*) We will monitor and review proposed environmental regulations and may challenge those that add considerable cost with limited environmental benefit. Minnesota Power will continue to pursue customer growth opportunities and cost recovery rider approvals for transmission, renewable and environmental investments, as well as work with regulators to earn a fair rate of return.

Regulatory Matters. Entities within our Regulated Operations segment are under the jurisdiction of the MPUC, FERC, PSCW and NDPSC. See Note 4. Regulatory Matters for discussion of regulatory matters within these jurisdictions.

2016 Minnesota General Rate Case. In November 2016, Minnesota Power filed a retail rate increase request with the MPUC seeking an average increase of approximately 9 percent for retail customers. The rate filing sought a return on equity of 10.25 percent and a 53.81 percent equity ratio. On an annualized basis, the requested final rate increase would have generated approximately $55 million in additional revenue. In December 2016, Minnesota Power filed a request to modify its original interim rate proposal reducing its requested interim rate increase to $34.7 million from the original request of approximately $49 million due to a change in its electric sales forecast. In December 2016 orders, the MPUC accepted the November 2016 filing as complete and authorized an annual interim rate increase of $34.7 million beginning January 1, 2017 .

On February 23, 2017, Minnesota Power filed an additional request to further reduce its requested interim rate increase. In an order dated April 13, 2017, the MPUC approved Minnesota Power's updated retail rate request resulting in a reduction in the annual interim rate increase to $32.2 million beginning May 1, 2017. As a result of working with intervenors and further developments as the rate review progressed, Minnesota Power's final rate request was adjusted to approximately $49 million on an annualized basis. At a hearing on January 18, 2018, the MPUC made determinations regarding Minnesota Power's general rate case including allowing a return on common equity of 9.25 percent and a 53.81 percent equity ratio. Upon commencement of final rates, we expect additional revenue of approximately $13 million on an annualized basis. Final rates are expected to commence in the fourth quarter of 2018; interim rates will be collected through this period which will be fully offset by the recognition of a corresponding reserve. As a result of the MPUC's decisions on January 18, 2018, Minnesota Power has recorded a reserve for an interim rate refund of approximately $32 million as of December 31, 2017 . The MPUC also disallowed recovery of Minnesota Power's regulatory asset for deferred fuel adjustment clause costs due to the anticipated adoption of a forward-looking fuel adjustment clause methodology resulting in a $19.5 million pre-tax charge to Fuel, Purchased Power and Gas – Utility in 2017. An order from the MPUC setting forth the effective date of final rates is expected by March 12, 2018. Minnesota Power will review this order for potential reconsideration of certain issues at that time.

As part of its decision in Minnesota Power's 2016 general rate case, the MPUC extended the depreciable lives of Boswell Unit 3, Unit 4 and common facilities to 2050 primarily to mitigate rate increases for our customers, and shortened the depreciable lives of Boswell Unit 1 and Unit 2 to 2022, resulting in a decrease to depreciation expense of approximately $25 million pre-tax in 2017.

Energy-Intensive Trade-Exposed Customer Rates. An EITE customer ratemaking law was enacted in 2015 which established that it is the energy policy of Minnesota to have competitive rates for certain industries such as mining and forest products. In 2015, Minnesota Power filed a rate schedule petition with the MPUC for EITE customers and a corresponding rider for EITE cost recovery. In a March 2016 order, the MPUC dismissed the petition without prejudice. In June 2016, Minnesota Power filed a revised EITE petition with the MPUC which included additional information on the net benefits analysis, limits on eligible customers and term lengths for the EITE discount. The rate adjustments were intended to be revenue and cash flow neutral to Minnesota Power. The MPUC approved a reduction in rates for EITE customers in a December 2016 order and subsequently approved cost recovery in an order dated April 20, 2017; collection of the discount was subject to the MPUC's review of Minnesota Power's compliance filing implementing approval of a recovery mechanism, with the subsequent order issued on October 13, 2017, that modified the order dated April 20, 2017. During 2017, Minnesota Power provided discounts of $8.6 million which were recorded as a receivable. On September 29, 2017, Minnesota Power informed its EITE customers that it had suspended the EITE discount due to a concern that it was not revenue and cash flow neutral to Minnesota Power based on an MPUC decision at a hearing on September 7, 2017, as well as the interim rate reduction and decisions in its 2016 general rate case. Based on the MPUC's decisions at a hearing on January 18, 2018, as part of Minnesota Power's 2016 general rate case, Minnesota Power reinstated the EITE discount effective January 1, 2018. Minnesota Power expects the discount to EITE customers to be approximately $15 million annually based on EITE customer current operating levels. While interim rates are in effect for Minnesota Power's 2016 general rate case, EITE discounts will offset interim rate refund reserves for non-EITE customers.

2016 Wisconsin General Rate Case. SWL&P's current retail rates are based on a 2017 PSCW retail rate order effective August 14, 2017, that allows for a 10.5 percent return on common equity and a 55 percent equity ratio. SWL&P's retail rates prior to August 14, 2017, were based on a 2012 PSCW retail rate order that provided for a 10.9 percent return on equity. The 2017 PSCW retail rate order authorizes SWL&P to collect on average a 2.9 percent increase in rates for retail customers (3.8 percent increase in electric rates; 4.8 percent decrease in natural gas rates; and 9.8 percent increase in water rates). On an annualized basis, SWL&P expects to collect additional revenue of $2.5 million .

Industrial Customers and Prospective Additional Load

Industrial Customers . Electric power is one of several key inputs in the taconite mining, iron concentrate, paper, pulp and secondary wood products, pipeline and other industries. Approximately 50 percent of our regulated utility kWh sales in 2017 (45 percent in 2016 and 46 percent in 2015) were made to our industrial customers. We expect industrial sales of approximately 7.0 million to 7.5 million MWh in 2018 (7.3 million MWh in 2017 ; 6.5 million MWh in 2016).

Taconite and Iron Concentrate . Minnesota Power's taconite customers are capable of producing up to approximately 41 million tons of taconite pellets annually. Taconite pellets produced in Minnesota are primarily shipped to North American steel making facilities that are part of the integrated steel industry. Steel produced from these North American facilities is used primarily in the manufacture of automobiles, appliances, pipe and tube products for the gas and oil industry, and in the construction industry. Historically, less than five percent of Minnesota taconite production has been exported outside of North America. Minnesota Power also provides electric service to three iron concentrate facilities capable of producing up to approximately 4 million tons of iron concentrate per year. Iron concentrate is used in the production of taconite pellets. These iron concentrate facilities are owned in whole, or in part, by ERP Iron Ore and are currently idled. (See *ERP Iron Ore / Magnetation* .)

There has been a general historical correlation between U.S. steel production and Minnesota taconite production. The American Iron and Steel Institute, an association of North American steel producers, reported that U.S. raw steel production operated at approximately 74 percent of capacity in 2017 (71 percent in 2016 and in 2015). The World Steel Association, an association of over 160 steel producers, national and regional steel industry associations, and steel research institutes representing approximately 85 percent of world steel production, projected U.S. steel consumption in 2018 will increase by approximately 1 percent compared to 2017 .

Minnesota Power's taconite customers may experience annual variations in production levels due to such factors as economic conditions, short-term demand changes or maintenance outages. We estimate that a one million ton change in Minnesota Power's taconite customers' production would impact our annual earnings per share by approximately $0.04 , net of expected power marketing sales at current prices. Changes in wholesale electric prices or customer contractual demand nominations could impact this estimate. Minnesota Power proactively sells power in the wholesale power markets that is temporarily not required by industrial customers to optimize the value of its generating facilities. Long-term reductions in taconite production or a permanent shut down of a taconite customer may lead Minnesota Power to file a general rate case to recover lost revenue.

Outlook (Continued)
Industrial Customers and Prospective Additional Load (Continued)

USS Corporation . In 2015, USS Corporation temporarily idled its Minnesota Ore Operations - Keetac plant in Keewatin, Minnesota, and a portion of its Minnesota Ore Operations - Minntac plant in Mountain Iron, Minnesota. These actions were due to high inventory levels and ongoing adjustment of its steel producing operations throughout North America. Global influences in the market, including a higher level of imports, unfairly traded products and reduced steel prices, were cited as having an impact. USS Corporation returned its Minntac plant to full production in 2015, and in the first quarter of 2017, USS Corporation restarted its Keetac plant. USS Corporation has the capability to produce approximately 5 million tons and 15 million tons of taconite annually at its Keetac and Minntac plants, respectively.

United Taconite . On May 16, 2017, Cliffs announced that production of a fully fluxed taconite pellet has started at its United Taconite facility. The product replaces a flux pellet previously made at Cliffs' indefinitely idled Empire operation in Michigan. United Taconite has the capability to produce approximately 5 million tons of taconite annually.

Northshore Mining . Cliffs has announced that it is investing further in Minnesota ore operations, specifically it plans to invest approximately $75 million through 2020 to expand capacity for producing direct reduced-grade pellets at Northshore Mining. The additional direct reduced-grade pellets could be sold commercially or used to supply Cliff's planned hot briquetted iron production plant in Toledo, Ohio. Minnesota Power has a long-term PSA through 2031 with Silver Bay Power, which provides the majority of the electric service requirements for Northshore Mining. (See *Silver Bay Power* .)

Silver Bay Power . In 2016, Minnesota Power and Silver Bay Power entered into a long-term PSA through 2031. Silver Bay Power supplies approximately 90 MW of load to Northshore Mining, an affiliate of Silver Bay Power, which has been served predominately through self-generation by Silver Bay Power. In the years 2016 through 2019, Minnesota Power is supplying Silver Bay Power with at least 50 MW of energy and Silver Bay Power has the option to purchase additional energy from Minnesota Power as it transitions away from self-generation. On December 31, 2019, Silver Bay Power will cease self-generation and Minnesota Power will supply the energy requirements for Silver Bay Power.

ERP Iron Ore / Magnetation . In 2015, Magnetation announced that it had filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the District of Minnesota, citing the significant decrease in global iron ore prices and its existing capital structure. In January 2016, Magnetation idled its Plant 2 facility in Bovey, Minnesota. In October 2016, the bankruptcy court approved plans to idle Magnetation's Plant 4 facility near Grand Rapids, Minnesota, and its pellet plant in Reynolds, Indiana, as well as terminate Magnetation's pellet purchase agreement with AK Steel Corporation. The company subsequently idled the facilities and stated it was preserving the plants and their value for a potential buyer. On January 30, 2017, ERP Iron Ore purchased substantially all of Magnetation's assets pursuant to an asset purchase agreement approved by the bankruptcy court. Although we cannot predict whether the facilities will be restarted, Minnesota Power would serve the Plant 2 and Plant 4 facilities through ERP Iron Ore's assumption of the existing electric service agreement.

Paper, Pulp and Secondary Wood Products . Minnesota Power serves a number of customers in the paper, pulp and secondary wood products industry. The four major paper and pulp mills we serve reported operating at, or near, full capacity in 2017 . Lower levels of production are expected in 2018 as a result of the closure of the smaller of the two paper machines located at UPM Blandin in the fourth quarter of 2017. (See *UPM Blandin* .)

UPM Blandin . On October 24, 2017, UPM-Kymmene Corporation announced that in light of the global market situation for graphic papers, and to sustain its competitiveness and leading position in the market, it planned to permanently close the smaller of UPM Blandin's two paper machines located in Grand Rapids, Minnesota; the closure was completed in the fourth quarter of 2017. Paper production related to the other paper machine is planned to continue at UPM Blandin. Minnesota Power provides electric and steam service to UPM Blandin.

Prospective Additional Load. Minnesota Power is pursuing new wholesale and retail loads in and around its service territory. Currently, several companies in northeastern Minnesota continue to progress in the development of natural resource-based projects that represent long-term growth potential and load diversity for Minnesota Power. We cannot predict the outcome of these projects.

Nashwauk Public Utilities Commission . Mesabi Metallics is a retail customer of the Nashwauk Public Utilities Commission, and Minnesota Power has a wholesale electric contract with the Nashwauk Public Utilities Commission for electric service through at least December 2032. Mesabi Metallics filed for bankruptcy protection in July 2016, under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the District of Delaware. On June 13, 2017, the bankruptcy court approved a settlement plan for a consortium led by Chippewa Capital Partners LLC to take control of the project, subject to certain stipulations. On December 22, 2017, Mesabi Metallics emerged from bankruptcy under the ownership of Chippewa Capital Partners LLC.

Outlook (Continued)
Industrial Customers and Prospective Additional Load (Continued)

PolyMet . PolyMet is planning to start a new copper-nickel and precious metal (non-ferrous) mining operation in northeastern Minnesota. In 2015, PolyMet announced the completion of the final EIS by state and federal agencies, which was subsequently published in the Federal Register and Minnesota Environmental Quality Board Monitor. The Minnesota Department of Natural Resources (DNR) issued its Record of Decision in March 2016, finding the final EIS adequate. In July 2016, PolyMet submitted applications for water-related permits with the State of Minnesota, and in August 2016, an application for an air quality permit was submitted to the MPCA. In November 2016, PolyMet submitted a state permit to mine application to the DNR detailing its operational plans for the mine. On January 5, 2018, the DNR released PolyMet's draft permit to mine and opened a public comment period through March 6, 2018. Public hearings were held in February 2018 to review the draft permit to mine, as well as the MPCA's recently released draft water quality permit, draft air quality permit and draft water quality certification. The final EIS also requires Records of Decision by the federal agencies, which are expected in 2018, before final action can be taken on the required federal permits to construct and operate the mining operation. On January 9, 2017, the U.S. Forest Service signed the Final Record of Decision authorizing a land exchange with PolyMet, which upon completion of title transfer will result in PolyMet obtaining surface rights to land needed to develop its mining operation. Minnesota Power could supply between 45 MW and 50 MW of load under a ten-year power supply contract with PolyMet that would begin upon start-up of operations.

EnergyForward. Minnesota Power is executing *EnergyForward* , a strategic plan for assuring reliability, protecting affordability and further improving environmental performance. The plan includes completed and planned investments in wind, solar, natural gas and hydroelectric power, construction of additional transmission capacity, the installation of emissions control technology and the idling of certain coal-fired generating facilities.

On July 28, 2017, Minnesota Power submitted a resource package to the MPUC requesting approval of PPAs for the output of a 250 MW wind energy facility and a 10 MW solar energy facility as well as approval of a 250 MW natural gas energy PPA. These agreements will be subject to MPUC approval of the construction of a 525 MW to 550 MW combined-cycle natural gas-fired generating facility which will be jointly owned by Dairyland Power Cooperative and a subsidiary of ALLETE. Minnesota Power would purchase approximately 50 percent of the facility's output starting in 2025. In an order dated September 19, 2017, the MPUC approved Minnesota Power's request that approval for the natural gas energy PPA be decided through an administrative law judge process. The administrative law judge is expected to provide a recommendation by July 2018, and the Company anticipates a MPUC decision in the second half of 2018. The MPUC did not take any action regarding the wind and solar energy PPAs which will be refiled separately from the natural gas energy PPA.

Integrated Resource Plan. In 2015, Minnesota Power filed its 2015 IRP with the MPUC which contained steps in its *EnergyForward* strategic plan, and included an analysis of a variety of existing and future energy resource alternatives and a projection of customer cost impact by class. In a July 2016 order, the MPUC approved Minnesota Power's 2015 IRP with modifications. The order accepted Minnesota Power's plans for Taconite Harbor, directed Minnesota Power to retire Boswell Units 1 and 2 no later than 2022, required an analysis of generation and demand response alternatives to be filed with a natural gas resource proposal, and required Minnesota Power to conduct request for proposals for additional wind, solar and demand response resource additions subject to further MPUC approvals. In October 2016, Minnesota Power announced that Boswell Units 1 and 2 will be retired in 2018 as part of its *EnergyForward* strategic plan. In an order dated September 19, 2017, the MPUC approved Minnesota Power's request to extend the next IRP filing deadline until October 1, 2019. (See Note 4. Regulatory Matters.)

Renewable Energy. Minnesota Power's 2015 IRP includes an update on its plans and progress in meeting the Minnesota renewable energy milestones through 2025. Minnesota Power continues to execute its renewable energy strategy through renewable projects that will ensure it meets the identified state mandate at the lowest cost for customers. Minnesota Power has exceeded the interim milestone requirements to date and expects 28 percent of its applicable retail and municipal energy sales will be supplied by renewable energy sources in 2018 . (See Item 1. Business – Regulated Operations – Minnesota Legislation and *EnergyForward* .)

Outlook (Continued)
EnergyForward (Continued)

Minnesota Solar Energy Standard . Minnesota law requires at least 1.5 percent of total retail electric sales, excluding sales to certain customers, to be generated by solar energy by the end of 2020. At least 10 percent of the 1.5 percent mandate must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 40 kW or less and community solar garden subscriptions. In a 2016 order, the MPUC approved Camp Ripley, a 10 MW utility scale solar project at the Camp Ripley Minnesota Army National Guard base and training facility near Little Falls, Minnesota, as eligible to meet the solar energy standard and for current cost recovery. Camp Ripley was completed in the fourth quarter of 2016. In a July 2016 order, the MPUC approved a community solar garden project in northeastern Minnesota, which is comprised of a 1 MW solar array owned and operated by a third party with the output purchased by Minnesota Power and a 40 kW solar array that is owned and operated by Minnesota Power. Minnesota Power believes Camp Ripley and the community solar garden arrays will meet approximately one-third of the overall mandate. Additionally, in an order dated February 10, 2017, the MPUC approved Minnesota Power's proposal to increase the amount of solar rebates available for customer-sited solar installations and recover costs of the program through Minnesota Power's renewable cost recovery rider. The proposal to incentivize customer-sited solar installations and the community solar garden subscriptions is expected to meet a portion of the required small scale solar mandate.

Minnesota Power has approval for current cost recovery of investments and expenditures related to compliance with the Minnesota Solar Energy Standard. Currently, there is no approved customer billing rate for solar costs.

Wind Energy . Minnesota Power's wind energy facilities consist of Bison (497 MW) located in North Dakota and Taconite Ridge (25 MW) located in northeastern Minnesota. Minnesota Power also has two long-term wind energy PPAs with an affiliate of NextEra Energy, Inc. to purchase the output from Oliver Wind I (50 MW) and Oliver Wind II (48 MW) located in North Dakota.

Minnesota Power uses the 465 -mile, 250 -kV DC transmission line that runs from Center, North Dakota, to Duluth, Minnesota, to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity delivered to its system over this transmission line from Square Butte's lignite coal-fired generating unit. The DC transmission line capacity can be increased if renewable energy or transmission needs justify investments to upgrade the line.

Updated customer billing rates for the renewable cost recovery rider, which includes investments and expenditures related to Bison, were approved by the MPUC in an order dated November 8, 2017, which allows Minnesota Power to charge retail customers on a current basis for the costs of constructing certain renewable investments plus a return on the capital invested.

In a November 2016 order, the MPUC directed Minnesota Power to attribute all North Dakota investment tax credits realized from Bison to Minnesota Power regulated retail customers. As a result of the adverse regulatory outcome, Minnesota Power recorded a regulatory liability, and a reduction in Operating Revenue of approximately $15 million in 2016. The North Dakota investment tax credits previously recognized as income tax credits in Corporate and Other were reversed in 2016 resulting in an $8.8 million charge to net income in 2016. In December 2016, Minnesota Power submitted a request for reconsideration with the MPUC. In an order dated February 14, 2017, the MPUC decided to reconsider its November 2016 order.

In an order dated December 7, 2017, the MPUC modified its November 2016 order to allow Minnesota Power to account for North Dakota investment tax credits based on the long-standing regulatory precedents of stand-alone allocation methodology of accounting for income taxes. As a result of the favorable regulatory outcome, Minnesota Power recorded a reduction in its regulatory liability and an increase in Operating Revenue of approximately $14 million in 2017. The North Dakota investment tax credits were reestablished as income tax credits in Corporate and Other, resulting in a $7.9 million increase to net income in 2017.

The stand-alone method provides that income taxes (and credits) are calculated as if Minnesota Power was the only entity included in ALLETE's consolidated federal and unitary state income tax returns. Minnesota Power has recorded a regulatory liability for North Dakota investment tax credits generated by its jurisdictional activity and expected to be realized in the future. North Dakota investment tax credits attributable to ALLETE's apportionment and income of ALLETE's other subsidiaries are included in Corporate and Other operations.

Outlook (Continued)
EnergyForward (Continued)

Tenaska PPA. On May 10, 2017, Minnesota Power and an affiliate of Tenaska signed a long-term PPA that provides for Minnesota Power to purchase the energy and associated capacity from a 250 MW wind energy facility in southwest Minnesota for a 20 -year period beginning in 2020. The agreement provides for the purchase of output from the facility at fixed energy prices. There are no fixed capacity charges, and Minnesota Power will only pay for energy as it is delivered. This agreement is subject to MPUC approval of the construction of a 525 MW to 550 MW combined-cycle natural gas-fired generating facility which will be jointly owned by Dairyland Power Cooperative and a subsidiary of ALLETE, and construction of the wind energy facility. (See Note 4. Regulatory Matters.)

Manitoba Hydro . Minnesota Power has five long-term PPAs with Manitoba Hydro. The first PPA expires in May 2020 . Under this agreement, Minnesota Power is purchasing 50 MW of capacity and the energy associated with that capacity. Both the capacity price and the energy price are adjusted annually by the change in a governmental inflationary index. Under the second PPA, Minnesota Power is purchasing surplus energy through April 2022 . This energy-only agreement primarily consists of surplus hydro energy on Manitoba Hydro's system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement, Minnesota Power will purchase at least one million MWh of energy over the contract term.

The third PPA provides for Minnesota Power to purchase 250 MW of capacity and energy from Manitoba Hydro for 15 years beginning in 2020. The agreement is subject to construction of additional transmission capacity between Manitoba and the U.S., along with construction of new hydroelectric generating capacity in Manitoba. (See Item 1. Business – Regulated Operations – Transmission and Distribution – Great Northern Transmission Line.) The capacity price is adjusted annually until 2020 by the change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for the change in a governmental inflationary index and a natural gas index, as well as market prices.

The fourth PPA provides for Minnesota Power to purchase up to 133 MW of energy from Manitoba Hydro for 20 years beginning in 2020. The pricing under this PPA is based on forward market prices. The PPA is subject to the construction of the GNTL. (See Item 1. Business – Regulated Operations – Transmission and Distribution – Great Northern Transmission Line.)

The fifth PPA provides for Minnesota Power to purchase 50 MW of capacity from Manitoba Hydro at fixed prices. The PPA began in June 2017 and expires in May 2020.

Transmission . We continue to make investments in transmission opportunities that strengthen or enhance the transmission grid or take advantage of our geographical location between sources of renewable energy and end users. These include the GNTL, investments to enhance our own transmission facilities, investments in other transmission assets (individually or in combination with others), and our investment in ATC. See also Item 1. Business – Regulated Operations.

Energy Infrastructure and Related Services.

ALLETE Clean Energy.

ALLETE Clean Energy focuses on developing, acquiring, and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates, in four states, approximately 535 MW of nameplate capacity wind energy generation that is contracted under PSAs of various durations. ALLETE Clean Energy also engages in the development of wind energy facilities to operate under long-term PSAs or for sale to others upon completion.

ALLETE Clean Energy believes the market for renewable energy in North America is robust, driven by several factors including environmental regulation, tax incentives, societal expectations and continual technology advances. State renewable portfolio standards, and state or federal regulations to limit GHG emissions are examples of environmental regulation or public policy that we believe will drive renewable energy development.

ALLETE Clean Energy's strategy includes the safe, reliable, optimal and profitable operation of its existing facilities. This includes a strong safety culture, the continuous pursuit of operational efficiencies at existing facilities and cost controls. ALLETE Clean Energy generally acquires facilities in liquid power markets and its strategy includes the exploration of PSA extensions upon expiration of existing contracts.

Outlook (Continued)
ALLETE Clean Energy (Continued)

ALLETE Clean Energy will pursue growth through acquisitions or project development for others. ALLETE Clean Energy is targeting acquisitions of existing facilities up to 200 MW each, which have long-term PSAs in place for the facilities' output. At this time, ALLETE Clean Energy expects acquisitions will be primarily wind or solar facilities in North America. ALLETE Clean Energy is also targeting the development of new facilities up to 200 MW each, which will have long-term PSAs in place for the output or may be sold upon completion.

Federal production tax credit qualification is important to development project economics, and ALLETE Clean Energy invested in equipment in late 2016 and late 2017 to meet production tax credit safe harbor provisions which provides an opportunity to seek development of up to approximately 1,500 MW of qualified wind projects through 2021. ALLETE Clean Energy will also invest approximately $80 million through 2020 to requalify up to 385 WTGs at its Storm Lake I, Storm Lake II and Lake Benton wind energy facilities for production tax credits. We anticipate annual production tax credits relating to these projects of approximately $5 million in 2018, $10 million in 2019, $15 million to $20 million annually in 2020 through 2027 and decreasing thereafter through 2030.

On January 3, 2017, ALLETE Clean Energy announced that it will develop a wind energy facility of up to 50 MW after securing a 25-year PSA with Montana-Dakota Utilities, which includes an option to purchase the facility upon completion. We expect Montana-Dakota Utilities to exercise the option in the first quarter of 2018; construction and sale is expected to be completed in December 2018. Revenue is expected to be recognized upon completion; if the wind energy facility is not completed and sold in 2018, revenue and related margins would be recognized in 2019. ALLETE Clean Energy constructed and sold a 107 MW wind energy facility to Montana-Dakota Utilities in 2015. On March 16, 2017, ALLETE Clean Energy announced it will build, own and operate a separate 100 MW wind energy facility pursuant to a 20-year PSA with Northern States Power; construction is expected to begin in late 2018.

ALLETE Clean Energy manages risk by having a diverse portfolio of assets, which includes PSA expiration, technology and geographic diversity. The current portfolio of approximately 535 MW is subject to typical variations in seasonal wind with higher wind resources typically available in the winter months. The majority of its planned maintenance leverages this seasonality and is performed during lower wind periods. The current mix of PSA expiration and geographic location for existing facilities is as follows:

Wind Energy Facility	Location	Capacity MW	PSA MW	PSA Expiration
Armenia Mountain	Pennsylvania	100.5	100%	2024
Chanarambie/Viking	Minnesota	97.5		
PSA 1			12%	2018
PSA 2			88%	2023
Condon	Oregon	50	100%	2022
Lake Benton	Minnesota	104	100%	2028
Storm Lake I	Iowa	108	100%	2019
Storm Lake II	Iowa	77		
PSA 1			90%	2019
PSA 2			10%	2032

U.S. Water Services.

U.S. Water Services provides integrated water management for industry by combining chemical, equipment, engineering and service for customized solutions to reduce water and energy usage and improve efficiency. U.S. Water Services is located in 49 states and Canada, and has an established base of approximately 4,900 customers. U.S. Water Services differentiates itself from the competition by developing synergies between established solutions in engineering, equipment and chemical water treatment, and helping customers achieve efficient and sustainable use of their water and energy systems. U.S. Water Services is a leading provider to the biofuels industry, and also serves the commercial and institutional markets, food and beverage, light manufacturing, power generation, and midstream oil and gas industries, among others. U.S. Water Services principally relies upon recurring revenues from a diverse mix of industrial customers. U.S. Water Services sells certain products which are seasonal in nature, with higher demand typically realized in warmer months; generally, lower sales occur in the first quarter of each year.

Outlook (Continued)
U.S. Water Services (Continued)

Our strategy is to grow U.S. Water Services' presence in North America by adding customers, products, markets and new geographies. We believe water scarcity and a growing emphasis on conservation will continue to drive significant growth in the industrial, commercial and governmental sectors leading to organic revenue growth for U.S. Water Services. U.S. Water Services also expects to pursue periodic strategic tuck-in acquisitions with a purchase price in the $10 million to $50 million range. Priority will be given to acquisitions which expand its geographic reach, add new technology, or deepen its capabilities to serve its expanding customer base.

On September 1, 2017, U.S. Water Services acquired Tonka Water for total consideration of $19.2 million. Tonka Water is a supplier of municipal and industrial water treatment systems that will expand U.S. Water Services' geographic and customer markets.

U.S. Water Services expects cash flow from operations of approximately $15 million in 2018 ($12 million in 2017).

Corporate and Other.

BNI Energy. In 2017 , BNI Energy sold a record 4.7 million tons of coal (3.8 million tons in 2016) and anticipates 2018 sales will be lower than 2017 primarily due to an expected outage for one of its customers. BNI Energy operates under cost-plus fixed fee agreements extending through December 31, 2037.

ALLETE Properties. ALLETE Properties represents our legacy Florida real estate investment. Market conditions can impact land sales and could result in our inability to cover our cost basis, operating expenses or fixed carrying costs such as community development district assessments and property taxes. ALLETE Properties' major projects in Florida are Town Center at Palm Coast and Palm Coast Park, with approximately 2,000 acres combined of land available for sale. (See Item 1. Business – Corporate and Other – ALLETE Properties.) In addition to these two projects, ALLETE Properties has approximately 800 acres of other land available for sale.

In recent years, market conditions for real estate in Florida have required us to review our land inventories for impairment. In 2015, the Company reevaluated its strategy related to the real estate assets of ALLETE Properties in response to market conditions and transaction activity. The revised strategy incorporated the possibility of a bulk sale of its entire portfolio. Proceeds from a bulk sale would be strategically deployed to support growth in ALLETE Clean Energy and U.S. Water Services, collectively our Energy Infrastructure and Related Services businesses. ALLETE Properties also continues to pursue sales of individual parcels over time. ALLETE Properties will continue to maintain key entitlements and infrastructure without making additional investments or acquisitions.

Income Taxes

ALLETE's aggregate federal and multi-state statutory tax rate is approximately 41 percent for 2017 . On an ongoing basis, ALLETE's statutory tax rate will be reduced to approximately 28 percent as a result of the federal income tax rate change of the TCJA. ALLETE also has tax credits and other tax adjustments that reduce the combined statutory rate to the effective tax rate. These tax credits and adjustments historically have included items such as investment tax credits, production tax credits, AFUDC-Equity, depletion, as well as other items. The annual effective rate can also be impacted by such items as changes in income before income taxes, state and federal tax law changes that become effective during the year, business combinations, tax planning initiatives and resolution of prior years' tax matters. We expect our effective tax rate to be approximately negative 10 percent for 2018 primarily due to a lower statutory tax rate resulting from the TCJA, and federal production tax credits as a result of wind energy generation. We also expect that our effective tax rate will be lower than the combined statutory rate over the next 12 years due to production tax credits attributable to our wind energy generation.

We expect the federal income tax rate change of the TCJA to result in lower income tax expense on an ongoing basis for our Regulated Operations, ALLETE Clean Energy and U.S. Water Services segments as well as our Corporate and Other businesses. The lower income tax expense for our Regulated Operations segment is expected to be mostly offset by lower revenue as most of the benefit is expected to be passed back to customers through lower rates. We do not expect a material impact on the Company's ability to utilize its federal and state NOL and tax credit carryforwards due to the TCJA.

Liquidity and Capital Resources

Liquidity Position. ALLETE is well-positioned to meet its liquidity needs. As of December 31, 2017 , we had cash and cash equivalents of $98.9 million , $395.1 million in available consolidated lines of credit and a debt-to-capital ratio of 42 percent.

Capital Structure. ALLETE's capital structure for each of the last three years is as follows:

As of December 31	2017	%	2016	%	2015	%
Millions						
ALLETE Equity	$2,068.2	58	$1,893.0	55	$1,820.2	53
Non-Controlling Interest	—	—	—	—	2.2	—
Long-Term Debt (Including Current Maturities)	1,513.3	42	1,569.1	45	1,605.0	47
Notes Payable	—	—	—	—	1.6	—
	$3,581.5	100	$3,462.1	100	$3,429.0	100

Cash Flows. Selected information from ALLETE's Consolidated Statement of Cash Flows is as follows:

Year Ended December 31	2017	2016	2015
Millions			
Cash and Cash Equivalents at Beginning of Period	$27.5	$97.0	$145.8
Cash Flows from (used for)			
Operating Activities	402.9	332.0	340.1
Investing Activities	(229.0)	(276.2)	(618.8)
Financing Activities	(102.5)	(125.3)	229.9
Change in Cash and Cash Equivalents	71.4	(69.5)	(48.8)
Cash and Cash Equivalents at End of Period	$98.9	$27.5	$97.0

Operating Activities . Cash from operating activities was higher in 2017 compared to 2016 primarily due to a payment of $31.0 million made in 2016 as part of a long-term PSA between Minnesota Power and Silver Bay Power, as well as higher recoveries of our cost recovery riders, net income and non-cash items in 2017, partially offset by an increase in customer receivables and higher payments on accounts payable in 2017.

Cash from operating activities was lower in 2016 compared to 2015 primarily due to a payment of $31.0 million made as part of a long-term PSA between Minnesota Power and Silver Bay Power, cash contributions to our defined benefit pension plan and non-cash items, partially offset by higher net income, lower fuel inventory and increased recoveries through our cost recovery riders.

Investing Activities . Cash used for investing activities was lower in 2017 compared to 2016 primarily due to lower payments for capital expenditures in 2017, partially offset by the acquisition of Tonka Water and additional investments in ATC in 2017.

Cash used for investing activities was lower in 2016 compared to 2015 primarily due to a decrease in cash used for the acquisitions of subsidiaries, as well as fewer capital expenditures in 2016. In 2015, we acquired U.S. Water Services, and ALLETE Clean Energy acquired the Chanarambie/Viking and Armenia Mountain wind energy facilities. (See Note 6. Acquisitions.)

Financing Activities . Cash used for financing activities was lower in 2017 primarily due to higher proceeds received from the issuance of common stock of $86.0 million compared to $30.9 million in 2016, partially offset by higher contingent consideration payments in 2017 and repayments of long-term debt of $189.6 million in 2017, net of long-term debt issuances of $131.5 million in 2017. Additionally, in 2016 the Company paid $8.0 million to acquire the non-controlling interest of the limited liability company that owns the Condon wind energy facility. (See *Securities* and Note 6. Acquisitions.)

Cash used for financing activities decreased in 2016 compared to 2015 primarily due to lower proceeds from the issuance of long-term debt and common stock.

Liquidity and Capital Resources (Continued)

Working Capital . Additional working capital, if and when needed, generally is provided by consolidated bank lines of credit and the issuance of securities, including long-term debt, common stock and commercial paper. As of December 31, 2017 , we had consolidated bank lines of credit aggregating $407.0 million ($409.0 million as of December 31, 2016), the majority of which expire in October 2020. We had $11.9 million outstanding in standby letters of credit and no outstanding draws under our lines of credit as of December 31, 2017 ($11.1 million in standby letters of credit and no outstanding draws as of December 31, 2016). In addition, as of December 31, 2017 , we had 3.2 million original issue shares of our common stock available for issuance through Invest Direct and 2.9 million original issue shares of common stock available for issuance through a distribution agreement with Lampert Capital Markets, Inc. (See *Securities*.) The amount and timing of future sales of our securities will depend upon market conditions and our specific needs.

The remeasurement of deferred income tax assets and liabilities resulting from the TCJA for Minnesota Power and SWL&P were recorded as regulatory assets and liabilities. The net regulatory liabilities for Minnesota Power and SWL&P are expected to be passed back to customers over time primarily based upon the normalization provisions of the U.S. Internal Revenue Code over the life of the related property, plant and equipment with the remainder passed back based upon the determinations of regulatory authorities. The final amount and timing over which the benefits of the TCJA will be passed back to customers has not been determined, and therefore, the full cash flow impacts are still uncertain. (See Note 4. Regulatory Matters.)

Securities . We entered into a distribution agreement with Lampert Capital Markets, Inc., in 2008, as amended most recently in August 2016, with respect to the issuance and sale of up to an aggregate of 13.6 million shares of our common stock, without par value, of which 2.9 million shares remain available for issuance as of December 31, 2017 . For the year ended December 31, 2017 , 1.0 million shares of common stock were issued under this agreement, resulting in net proceeds of $65.7 million (0.1 million shares for net proceeds of $8.0 million in 2016 ; 1.3 million shares for net proceeds of $69.9 million in 2015). The shares issued in 2017 and 2016 were offered and sold pursuant to Registration Statement No. 333-212794, pursuant to which the remaining shares will continue to be offered for sale, from time to time. The shares issued in 2015 were offered and sold pursuant to Registration Statement No. 333-190335.

During the year ended December 31, 2017 , we issued 0.3 million shares of common stock through Invest Direct, the Employee Stock Purchase Plan, and the Retirement Savings and Stock Ownership Plan, resulting in net proceeds of $20.3 million (0.4 million shares for net proceeds of $22.9 million in 2016 ; 0.4 million shares for net proceeds of $25.9 million in 2015). These shares of common stock were registered under Registration Statement Nos. 333-211075, 333-188315, 333-183051 and 333-162890.

On June 1, 2017, ALLETE issued $80 million of its senior unsecured notes (the Notes) to certain institutional buyers in the private placement market. The Notes were issued in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended, to institutional accredited investors. The Notes bear interest at 3.11 percent and mature on June 1, 2027. (See Note 10. Short-Term and Long-Term Debt.)

On August 25, 2017, ALLETE entered into a $40 million term loan agreement (Term Loan). The Term Loan is an unsecured, single draw loan that is due on August 25, 2020, and may be prepaid at any time subject to a make-whole provision. The interest rate on the Term Loan is equal to LIBOR plus 1.025 percent . (See Note 10. Short-Term and Long-Term Debt.)

On November 2, 2017, ALLETE entered into a bond purchase agreement providing for the issuance and sale of $60 million of its First Mortgage Bonds (the Bonds) that bear interest at 4.07 percent . The Bonds will be issued on or about April 1, 2018, and will mature in April 2048. (See Note 10. Short-Term and Long-Term Debt.)

Financial Covenants . See Note 10. Short-Term and Long-Term Debt for information regarding our financial covenants.

Pension and Other Postretirement Benefit Plans. Management considers various factors when making funding decisions, such as regulatory requirements, actuarially determined minimum contribution requirements and contributions required to avoid benefit restrictions for the defined benefit pension plans. For the year ended December 31, 2017 , we contributed $1.7 million in cash and 0.2 million shares of ALLETE common stock, which had an aggregate value of $13.5 million when contributed, to the defined benefit pension plans. These shares of ALLETE common stock were contributed in reliance upon an exemption available pursuant to Section 4(a)(2) of the Securities Act of 1933, as amended. On January 8, 2018, we contributed $15.0 million in cash to the defined benefit pension plans. We do not expect to make any additional contributions to our defined benefit pension plans in 2018 , and we do not expect to make any contributions to our other postretirement benefit plans in 2018 . (See Note 12. Common Stock and Earnings Per Share and Note 15. Pension and Other Postretirement Benefit Plans.)

Liquidity and Capital Resources (Continued)

Off-Balance Sheet Arrangements . Off-balance sheet arrangements are discussed in Note 11. Commitments, Guarantees and Contingencies.

Contractual Obligations and Commercial Commitments . ALLETE has contractual obligations and other commitments that will need to be funded in the future, in addition to its capital expenditure programs. The following table summarizes contractual obligations and other commercial commitments as of December 31, 2017 :

	Payments Due by Period				
Contractual Obligations *(a)*	**Total**	**Less than 1 Year**	**1 to 3 Years**	**4 to 5 Years**	**After 5 Years**
Millions					
Long-Term Debt	$2,255.4	$126.1	$313.6	$284.8	$1,530.9
Pension *(b)*	458.0	46.3	92.1	91.6	228.0
Other Postretirement Benefit Plans *(b)*	97.2	9.2	19.1	19.2	49.7
Operating Lease Obligations	79.9	14.2	22.3	13.4	30.0
PPA Obligations *(c)*	2,283.1	104.5	222.1	289.5	1,667.0
Other Purchase Obligations	56.5	40.5	3.5	1.4	11.1
Total Contractual Obligations	$5,230.1	$340.8	$672.7	$699.9	$3,516.7

(a) Does not include $1.7 million of non-current unrecognized tax benefits due to uncertainty regarding the timing of future cash payments related to uncertain tax positions. (See Note 13. Income Tax Expense.)

(b) Represents the estimated future benefit payments for our defined benefit pension and other postretirement plans through 2027.

(c) Does not include the agreement with Manitoba Hydro expiring in 2022, as this contract is for surplus energy only; Oliver Wind I and Oliver Wind II, as Minnesota Power only pays for energy as it is delivered; and the agreement with Tenaska commencing in 2020 as it is subject to approval of the construction of a 525 MW to 550 MW combined-cycle natural gas-fired facility. (See Note 11. Commitments, Guarantees and Contingencies.)

Long-Term Debt. Our long-term debt obligations, including long-term debt due within one year, represent the principal amount of bonds, notes and loans which are recorded on the Consolidated Balance Sheet, plus interest. The table above assumes that the interest rates in effect at December 31, 2017 , remain constant through the remaining term. (See Note 10. Short-Term and Long-Term Debt.)

Pension and Other Postretirement Benefit Plans. Our pension and other postretirement benefit plan obligations represent our current estimate of future benefit payments through 2027. Pension contributions will be dependent on several factors including realized asset performance, future discount rate and other actuarial assumptions, Internal Revenue Service and other regulatory requirements, and contributions required to avoid benefit restrictions for the pension plans. Funding for the other postretirement benefit plans is impacted by realized asset performance, future discount rate and other actuarial assumptions, and utility regulatory requirements. These amounts are estimates and will change based on actual market performance, changes in interest rates and any changes in governmental regulations. (See Note 15. Pension and Other Postretirement Benefit Plans.)

PPA Obligations. PPA obligations represent our Square Butte, Manitoba Hydro, Minnkota Power and other PPA’s. (See Note 11. Commitments, Guarantees and Contingencies.)

Other Purchase Obligations. Other purchase obligations represents our minimum purchase commitments under coal and rail contracts, purchase obligations for certain capital expenditure projects, and long-term service agreements for wind energy facilities. (See Note 11. Commitments, Guarantees and Contingencies.)

Liquidity and Capital Resources (Continued)

Credit Ratings . Access to reasonably priced capital markets is dependent in part on credit and ratings. Our securities have been rated by Standard & Poor's and by Moody's. Rating agencies use both quantitative and qualitative measures in determining a company's credit rating. These measures include business risk, liquidity risk, competitive position, capital mix, financial condition, predictability of cash flows, management strength and future direction. Some of the quantitative measures can be analyzed through a few key financial ratios, while the qualitative ones are more subjective. Our current credit ratings are listed in the following table:

Credit Ratings	Standard & Poor's	Moody's
Issuer Credit Rating	BBB+	A3
Commercial Paper	A-2	P-2
First Mortgage Bonds	*(a)*	A1

(a) Not rated by Standard & Poor's.

The disclosure of these credit ratings is not a recommendation to buy, sell or hold our securities. Ratings are subject to revision or withdrawal at any time by the assigning rating organization. Each rating should be evaluated independently of any other rating.

On February 6, 2018, Standard & Poor's revised its credit rating outlook on ALLETE to negative from stable, while affirming its issuer and commercial paper ratings on ALLETE. Standard & Poor's cited the potential effect of the TCJA on the Company's cash flows and Standard & Poor's assessment of the Company's regulatory risk following Minnesota Power's recent general rate case as its rationale for issuing the negative outlook.

On February 8, 2018, Moody's issued a report on ALLETE noting that Minnesota Power's general rate case was credit negative. With respect to Minnesota Power's general rate case outcome, Moody's noted a lower return on equity, disallowance of various expenses, including a decision to disallow recovery of the prepaid pension asset, and a ruling against Minnesota Power's request to adopt an annual rate review mechanism. In addition, Moody's noted the potential negative impact of the TCJA on certain financial metrics used by Moody's.

The Company believes it is well-positioned to meet its liquidity needs. As of December 31, 2017 , we had cash and cash equivalents of $98.9 million , $395.1 million in available consolidated lines of credit and a debt-to-equity ratio of 42 percent. Our cash from operating activities for the year ended December 31, 2017 was $402.9 million . In addition, as of December 31, 2017, we had 3.2 million original issue shares of our common stock available for issuance through Invest Direct and 2.9 million original issue shares of common stock available for issuance through a distribution agreement with Lampert Capital Markets, Inc.

Common Stock Dividends . ALLETE is committed to providing a competitive dividend to its shareholders while at the same time funding its growth. The Company's long-term objective is to maintain a dividend payout ratio similar to our peers and provide for future dividend increases. Our targeted payout range is between 60 percent and 65 percent. In 2017 , we paid out 63 percent (66 percent in 2016 ; 69 percent in 2015) of our per share earnings in dividends. On January 23, 2018, our Board of Directors declared a dividend of $0.56 per share, which is payable on March 1, 2018, to shareholders of record at the close of business on February 15, 2018.

Capital Requirements

ALLETE's projected capital expenditures for the years 2018 through 2022 are presented in the following table. Actual capital expenditures may vary from the estimates due to changes in forecasted plant maintenance, regulatory decisions or approvals, future environmental requirements, base load growth, capital market conditions or executions of new business strategies.

Capital Requirements (Continued)

Capital Expenditures	2018	2019	2020	2021	2022	Total
Millions						
Regulated Operations						
Base and Other	$130	$190	$130	$170	$170	$790
Transmission Cost Recovery *(a)*	110	85	50	—	—	245
Regulated Operations Capital Expenditures	240	275	180	170	170	1,035
ALLETE Clean Energy	65	65	25	5	5	165
U.S. Water Services	5	5	5	10	10	35
Corporate and Other *(b)*	15	15	35	60	170	295
Total Capital Expenditures	$325	$360	$245	$245	$355	$1,530

(a) Estimated capital expenditures eligible for cost recovery outside of a general rate case. Our portion of transmission capital expenditures related to construction of the GNTL is estimated at approximately $245 million through 2020. (See Item 1. Business – Regulated Operations – Transmission and Distribution.)

(b) Our portion of capital expenditures related to construction of a 525 MW to 550 MW combined-cycle natural gas-fired generating facility, which will be jointly owned by Dairyland Power Cooperative and a subsidiary of ALLETE, is estimated at approximately $200 million through 2022, subject to regulatory approval. (See Item 7. Management's Discussion and Analysis – Outlook – EnergyForward.)

We are well positioned to meet our financing needs due to adequate operating cash flows, available additional working capital and access to capital markets. We will finance capital expenditures from a combination of internally generated funds, debt and equity issuance proceeds. We intend to maintain a capital structure with capital ratios near current levels. (See *Capital Structure.*)

Environmental and Other Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. A number of regulatory changes to the Clean Air Act, the Clean Water Act and various waste management requirements have recently been promulgated by both the EPA and state authorities. Minnesota Power's facilities are subject to additional requirements under many of these regulations. Minnesota Power is reshaping its generation portfolio, over time, to reduce its reliance on coal, has installed cost-effective emission control technology, and advocates for sound science and policy during rulemaking implementation. (See Note 11. Commitments, Guarantees and Contingencies.)

Market Risk

Securities Investments.

Available-for-Sale Securities. As of December 31, 2017 , our available-for-sale securities portfolio consisted primarily of securities held in other postretirement plans to fund employee benefits. (See Note 8. Investments.)

Market Risk (Continued)

INTEREST RATE RISK

We are exposed to risks resulting from changes in interest rates as a result of our issuance of variable rate debt. We manage our interest rate risk by varying the issuance and maturity dates of our fixed rate debt, limiting the amount of variable rate debt, and continually monitoring the effects of market changes in interest rates. We may also enter into derivative financial instruments, such as interest rate swaps, to mitigate interest rate exposure. The following table presents the long-term debt obligations and the corresponding weighted average interest rate as of December 31, 2017 :

	Expected Maturity Date							
Interest Rate Sensitive Financial Instruments	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**	**Total**	**Fair Value**
Long-Term Debt								
Fixed Rate – Millions	$63.4	$56.2	$89.0	$97.8	$88.0	$1,034.5	$1,428.9	$1,543.2
Average Interest Rate – %	2.8	7.6	4.2	3.8	3.7	4.4	4.4	
Variable Rate – Millions	$1.2	$1.4	$54.0	—	—	$27.8	$84.4	$84.4
Average Interest Rate – %	5.4	5.4	2.1	—	—	0.7	1.8	

Interest rates on variable rate long-term debt are reset on a periodic basis reflecting prevailing market conditions. Based on the variable rate debt outstanding as of December 31, 2017 , an increase of 100 basis points in interest rates would impact the amount of pre-tax interest expense by $0.8 million. This amount was determined by considering the impact of a hypothetical 100 basis point increase to the average variable interest rate on the variable rate debt outstanding as of December 31, 2017 .

COMMODITY PRICE RISK

Our regulated utility operations incur costs for power and fuel (primarily coal and related transportation) in Minnesota, and power and natural gas purchased for resale in our regulated service territory in Wisconsin. Minnesota Power's exposure to price risk for these commodities is significantly mitigated by the current ratemaking process and regulatory framework, which allows recovery of fuel costs in excess of those included in base rates or distribution of savings in fuel costs to ratepayers. SWL&P's exposure to price risk for natural gas is significantly mitigated by the current ratemaking process and regulatory framework, which allows the commodity cost to be passed through to customers. We seek to prudently manage our customers' exposure to price risk by entering into contracts of various durations and terms for the purchase of power and coal and related transportation costs (Minnesota Power) and natural gas (SWL&P).

POWER MARKETING

Minnesota Power's power marketing activities consist of: (1) purchasing energy in the wholesale market to serve its regulated service territory when energy requirements exceed generation output; and (2) selling excess available energy and purchased power. From time to time, Minnesota Power may have excess energy that is temporarily not required by retail and municipal customers in our regulated service territory. Minnesota Power actively sells any excess energy to the wholesale market to optimize the value of its generating facilities.

We are exposed to credit risk primarily through our power marketing activities. We use credit policies to manage credit risk, which includes utilizing an established credit approval process and monitoring counterparty limits.

Recently Adopted Accounting Standards.

New accounting standards are discussed in Note 1. Operations and Significant Accounting Policies of this Form 10-K.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Market Risk for information related to quantitative and qualitative disclosure about market risk.

Item 8. Financial Statements and Supplementary Data

See our Consolidated Financial Statements as of December 31, 2017 and 2016 , and for the years ended December 31, 2017 , 2016 and 2015 , and supplementary data, which are indexed in Item 15(a).

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2017 , evaluations were performed, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, on the effectiveness of the design and operation of ALLETE's disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act). Based upon those evaluations, our principal executive officer and principal financial officer have concluded that such disclosure controls and procedures are effective to provide assurance that information required to be disclosed in ALLETE's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f) or 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control – Integrated Framework (framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2017 .

The effectiveness of the Company's internal control over financial reporting as of December 31, 2017 , has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Controls

There has been no change in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Unless otherwise stated, the information required by this Item is incorporated by reference herein from our Proxy Statement for the 2018 Annual Meeting of Shareholders (2018 Proxy Statement) under the following headings:

- **Directors.** The information regarding directors will be included in the "Election of Directors" section;
- **Audit Committee Financial Expert.** The information regarding the Audit Committee financial expert will be included in the "Corporate Governance" section and the "Audit Committee Report" section;
- **Audit Committee Members.** The identity of the Audit Committee members will be included in the "Corporate Governance" section and the "Audit Committee Report" section;
- **Executive Officers.** The information regarding executive officers is included in Part I of this Form 10-K; and
- **Section 16(a) Compliance.** The information regarding Section 16(a) compliance will be included in the "Ownership of ALLETE Common Stock – Section 16(a) Beneficial Ownership Reporting Compliance" section.

Our 2018 Proxy Statement will be filed with the SEC within 120 days after the end of our 2017 fiscal year.

Code of Ethics. We have adopted a written Code of Ethics that applies to all of our employees, including our Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. A copy of our Code of Ethics is available on our website at www.allete.com and print copies are available without charge upon request to ALLETE, Inc., Attention: Secretary, 30 West Superior St., Duluth, Minnesota 55802. Any amendment to the Code of Ethics or any waiver of the Code of Ethics will be disclosed on our website at www.allete.com promptly following the date of such amendment or waiver.

Corporate Governance. The following documents are available on our website at www.allete.com and print copies are available upon request:

- Corporate Governance Guidelines;
- Audit Committee Charter;
- Executive Compensation Committee Charter; and
- Corporate Governance and Nominating Committee Charter.

Any amendment to these documents will be disclosed on our website at www.allete.com promptly following the date of such amendment.

Item 11. Executive Compensation

The information required for this Item is incorporated by reference herein from the "Compensation Discussion and Analysis," the "Compensation of Executive Officers," the "Compensation Committee Report" and the "Director Compensation" sections in our 2018 Proxy Statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required for this Item is incorporated by reference herein from the "Ownership of ALLETE Common Stock – Securities Owned by Certain Beneficial Owners" and the "Ownership of ALLETE Common Stock – Securities Owned by Directors and Management" sections in our 2018 Proxy Statement.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth the shares of ALLETE common stock available for issuance under the Company's equity compensation plans as of December 31, 2017 :

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants, and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans *(a)*
Equity Compensation Plans Approved by Security Holders	—	—	1,266,716
Equity Compensation Plans Not Approved by Security Holders	—	N/A	—
Total	—	—	1,266,716

(a) Excludes the number of securities shown in the first column as to be issued upon exercise of outstanding options, warrants, and rights. The amount shown is comprised of: (i) 1,005,861 shares available for issuance under the long-term incentive plan in the form of options, rights, restricted stock units, performance share awards, and other grants as approved by the Executive Compensation Committee of the Company's Board of Directors; (ii) 136,178 shares available for issuance under the Director Stock Plan as payment for a portion of the annual retainer payable to non-employee Directors; and (iii) 124,677 shares available for issuance under the ALLETE and Affiliated Companies Employee Stock Purchase Plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required for this Item is incorporated by reference herein from the "Corporate Governance" section in our 2018 Proxy Statement.

We have adopted a Related Person Transaction Policy which is available on our website at www.allete.com. Print copies are available without charge, upon request. Any amendment to this policy will be disclosed on our website at www.allete.com promptly following the date of such amendment.

Item 14. Principal Accounting Fees and Services

The information required for this Item is incorporated by reference herein from the "Audit Committee Report" section in our 2018 Proxy Statement.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a)	Certain Documents Filed as Part of this Form 10-K.	
(1)	Financial Statements	Page
	ALLETE	
	Report of Independent Registered Public Accounting Firm	73
	Consolidated Balance Sheet as of December 31, 2017 and 2016	75
	For the Years Ended December 31, 2017, 2016 and 2015	
	Consolidated Statement of Income	76
	Consolidated Statement of Comprehensive Income	77
	Consolidated Statement of Cash Flows	78
	Consolidated Statement of Equity	79
	Notes to Consolidated Financial Statements	80
(2)	Financial Statement Schedules	
	Schedule II – ALLETE Valuation and Qualifying Accounts and Reserves	142
	All other schedules have been omitted either because the information is not required to be reported by ALLETE or because the information is included in the Consolidated Financial Statements or the notes.	
(3)	Exhibits including those incorporated by reference.	

Exhibit Number

*3(a)1	—	Articles of Incorporation, amended and restated as of May 8, 2001 (filed as Exhibit 3(b) to the March 31, 2001, Form 10-Q, File No. 1-3548).
*3(a)2	—	Amendment to Articles of Incorporation, dated as of September 20, 2004 (filed as Exhibit 3 to the September 21, 2004, Form 8-K, File No. 1-3548).
*3(a)3	—	Amendment to Articles of Incorporation, dated as of May 12, 2009 (filed as Exhibit 3 to the June 30, 2009, Form 10-Q, File No. 1-3548).
*3(a)4	—	Amendment to Articles of Incorporation, dated as of May 11, 2010 (filed as Exhibit 3(a) to the May 14, 2010, Form 8-K, File No. 1-3548).
*3(a)5	—	Amendment to Certificate of Assumed Name, filed with the Minnesota Secretary of State on May 8, 2001 (filed as Exhibit 3(a) to the March 31, 2001, Form 10-Q, File No. 1-3548).
*3(b)	—	Bylaws, as amended effective May 11, 2010 (filed as Exhibit 3(b) to the May 14, 2010, Form 8-K, File No. 1-3548).
*4(a)1	—	Mortgage and Deed of Trust, dated as of September 1, 1945, between Minnesota Power & Light Company (now ALLETE) and The Bank of New York Mellon (formerly Irving Trust Company) and Andres Serrano (successor to Richard H. West), Trustees (filed as Exhibit 7(c), File No. 2-5865).
*4(a)2	—	Supplemental Indentures to ALLETE's Mortgage and Deed of Trust:

Number	Dated as of	Reference File	Exhibit
First	March 1, 1949	2-7826	7(b)
Second	July 1, 1951	2-9036	7(c)
Third	March 1, 1957	2-13075	2(c)
Fourth	January 1, 1968	2-27794	2(c)
Fifth	April 1, 1971	2-39537	2(c)
Sixth	August 1, 1975	2-54116	2(c)
Seventh	September 1, 1976	2-57014	2(c)
Eighth	September 1, 1977	2-59690	2(c)
Ninth	April 1, 1978	2-60866	2(c)
Tenth	August 1, 1978	2-62852	2(d)2
Eleventh	December 1, 1982	2-56649	4(a)3
Twelfth	April 1, 1987	33-30224	4(a)3
Thirteenth	March 1, 1992	33-47438	4(b)
Fourteenth	June 1, 1992	33-55240	4(b)
Fifteenth	July 1, 1992	33-55240	4(c)
Sixteenth	July 1, 1992	33-55240	4(d)
Seventeenth	February 1, 1993	33-50143	4(b)
Eighteenth	July 1, 1993	33-50143	4(c)
Nineteenth	February 1, 1997	1-3548 (1996 Form 10-K)	4(a)3
Twentieth	November 1, 1997	1-3548 (1997 Form 10-K)	4(a)3
Twenty-first	October 1, 2000	333-54330	4(c)3
Twenty-second	July 1, 2003	1-3548 (June 30, 2003, Form 10-Q)	4
Twenty-third	August 1, 2004	1-3548 (Sept. 30, 2004, Form 10-Q)	4(a)
Twenty-fourth	March 1, 2005	1-3548 (March 31, 2005, Form 10-Q)	4
Twenty-fifth	December 1, 2005	1-3548 (March 31, 2006, Form 10-Q)	4
Twenty-sixth	October 1, 2006	1-3548 (2006 Form 10-K)	4(a)3
Twenty-seventh	February 1, 2008	1-3548 (2007 Form 10-K)	4(a)3
Twenty-eighth	May 1, 2008	1-3548 (June 30, 2008, Form 10-Q)	4
Twenty-ninth	November 1, 2008	1-3548 (2008 Form 10-K)	4(a)3
Thirtieth	January 1, 2009	1-3548 (2008 Form 10-K)	4(a)4
Thirty-first	February 1, 2010	1-3548 (March 31, 2010, Form 10-Q)	4
Thirty-second	August 1, 2010	1-3548 (Sept. 30, 2010, Form 10-Q)	4
Thirty-third	July 1, 2012	1-3548 (July 2, 2012, Form 8-K)	4
Thirty-fourth	April 1, 2013	1-3548 (April 2, 2013, Form 8-K)	4
Thirty-fifth	March 1, 2014	1-3548 (March 31, 2014, Form 10-Q)	4
Thirty-sixth	June 1, 2014	1-3548 (June 30, 2014, Form 10-Q)	4
Thirty-seventh	September 1, 2014	1-3548 (Sept. 30, 2014, Form 10-Q)	4
Thirty-eighth	September 1, 2015	1-3548 (Sept. 30, 2015, Form 10-Q)	4(a)

Exhibit Number

*4(b)1	—	Mortgage and Deed of Trust, dated as of March 1, 1943, between Superior Water, Light and Power Company and Chemical Bank & Trust Company and Howard B. Smith, as Trustees, both succeeded by U.S. Bank National Association, as Trustee (filed as Exhibit 7(c), File No. 2-8668).
*4(b)2	—	Supplemental Indentures to Superior Water, Light and Power Company's Mortgage and Deed of Trust:

Number	Dated as of	Reference File	Exhibit
First	March 1, 1951	2-59690	2(d)(1)
Second	March 1, 1962	2-27794	2(d)1
Third	July 1, 1976	2-57478	2(e)1
Fourth	March 1, 1985	2-78641	4(b)
Fifth	December 1, 1992	1-3548 (1992 Form 10-K)	4(b)1
Sixth	March 24, 1994	1-3548 (1996 Form 10-K)	4(b)1
Seventh	November 1, 1994	1-3548 (1996 Form 10-K)	4(b)2
Eighth	January 1, 1997	1-3548 (1996 Form 10-K)	4(b)3
Ninth	October 1, 2007	1-3548 (2007 Form 10-K)	4(c)3
Tenth	October 1, 2007	1-3548 (2007 Form 10-K)	4(c)4
Eleventh	December 1, 2008	1-3548 (2008 Form 10-K)	4(c)3
Twelfth	December 2, 2013	1-3548 (2013 Form 10-K)	4(c)3

*4(c)	—	Note Purchase Agreement, dated as of June 8, 2007, between ALLETE and Thrivent Financial for Lutherans and The Northwestern Mutual Life Insurance Company (filed as Exhibit 10(a) to the June 30, 2007, Form 10-Q, File No. 1-3548).
*4(d)	—	Term Loan Agreement dated as of August 25, 2015, among ALLETE, as Borrower, the Lenders party hereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and J.P. Morgan Securities LLC, as Sole Lead Arranger and Sole Book Runner (filed as Exhibit 4 to the August 28, 2015, Form 8-K, File No. 1-3548).
*4(e)	—	Note Purchase and Guarantee Agreement dated as of November 5, 2015, among Armenia Mountain Wind LLC, AMW I Holding, LLC and the purchasers named therein (filed as Exhibit 4 to the November 12, 2015, Form 8-K, File No. 1-3548).
*4(f)	—	Note Purchase Agreement, dated December 8, 2016, between ALLETE and Hartford Investment Management Company, Northwestern Mutual Investment Management Company, The Northwestern Mutual Life Insurance Company and Nationwide Life insurance Company (filed as Exhibit 4 to the December 12, 2016, Form 8-K, File No. 1-3548).
*4(g)		Term Loan Agreement dated as of August 25, 2017, among ALLETE, as Borrower, the Lenders party hereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., as Syndication Agent, and JPMorgan Chase Bank, N.A., as Sole Lead Arranger and Sole Book Runner (filed as Exhibit 4 to the September 30, 2017, Form 10-Q, File No. 1-3548).
*10(a)	—	Power Purchase and Sale Agreement, dated as of May 29, 1998, between Minnesota Power, Inc. (now ALLETE) and Square Butte Electric Cooperative (filed as Exhibit 10 to the June 30, 1998, Form 10-Q, File No. 1-3548).
*10(b)	—	Credit Agreement dated as of November 4, 2013 among ALLETE, as Borrower, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and J.P. Morgan Securities LLC, as Sole Lead Arranger and Sole Book Runner (filed as Exhibit 10 to the November 4, 2013, Form 8-K, File No. 1-3548).
*10(c)1	—	Financing Agreement between Collier County Industrial Development Authority and ALLETE dated as of July 1, 2006 (filed as Exhibit 10(b)1 to the June 30, 2006, Form 10-Q, File No. 1-3548).
*10(c)2	—	Amended and Restated Letter of Credit Agreement, dated as of June 3, 2011, among ALLETE, the participating banks and Wells Fargo Bank, National Association, as Administrative Agent and Issuing Bank (filed as Exhibit 10(b) to the June 30, 2011, Form 10-Q, File No. 1-3548).
*10(c)3	—	First Amendment to Amended and Restated Letter of Credit Agreement, dated as of June 1, 2013, between ALLETE and Wells Fargo Bank, National Association, as Issuing Bank, Administrative Agent and Sole Participating Bank (filed as Exhibit 10(b) to the June 30, 2013, Form 10-Q, File No. 1-3548).
*10(d)	—	Agreement dated December 16, 2005, among ALLETE, Wisconsin Public Service Corporation and WPS Investments, LLC (filed as Exhibit 10(g) to the 2009 Form 10-K, File No. 1-3548).
+*10(e)1		ALLETE Executive Annual Incentive Plan, as amended and restated, effective January 1, 2011 (filed as Exhibit 10(h)1 to the 2010 Form 10-K, File No. 1-3548).
+*10(e)2	—	ALLETE Executive Annual Incentive Plan Form of Award Effective 2014 (filed as Exhibit 10(e)6 to the 2013 Form 10-K, File No. 1-3548).
+*10(e)3	—	ALLETE Executive Annual Incentive Plan Form of Award Effective 2015 (filed as Exhibit 10(e)6 to the 2014 Form 10-K, File No. 1-3548).
+*10(e)4	—	ALLETE Executive Annual Incentive Plan Form of Award Effective 2016 (filed as Exhibit 10(e)6 to the 2015 Form 10-K, File No. 1-3548).
+*10(e)5	—	ALLETE Executive Annual Incentive Plan Form of Award Effective 2017 (filed as Exhibit 10(e)6 to the 2016 Form 10-K, File No. 1-3548).
+*10(e)6	—	ALLETE Executive Annual Incentive Plan Form of Award Superior Water, Light and Power Effective 2017 (filed as Exhibit 10(e)7 to the 2016 Form 10-K, File No. 1-3548).

Exhibit Number		
+*10(f)1	—	ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (SERP I), as amended and restated, effective January 1, 2009 (filed as Exhibit 10(i)4 to the 2008 Form 10-K, File No. 1-3548).
+*10(f)2	—	Amendment to the ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (SERP I), effective January 1, 2011 (filed as Exhibit 10(i)2 to the 2010 Form 10-K, File No. 1-3548).
+*10(f)3	—	ALLETE and Affiliated Companies Supplemental Executive Retirement Plan II (SERP II), as amended and restated, effective January 1, 2015 (filed as Exhibit 10(f)3 to the 2014 Form 10-K, File No. 1-3548).
+*10(g)	—	ALLETE Deferred Compensation Trust Agreement, as amended and restated, effective December 15, 2012 (filed as Exhibit 10(j) to the 2012 Form 10-K, File No. 1-3548).
+*10(h)1	—	ALLETE Executive Long-Term Incentive Compensation Plan as amended and restated effective January 1, 2006 (filed as Exhibit 10 to the May 16, 2005, Form 8-K, File No. 1-3548).
+*10(h)2	—	Amendment to the ALLETE Executive Long-Term Incentive Compensation Plan, effective January 1, 2011 (filed as Exhibit 10(m)2 to the 2010 Form 10-K, File No. 1-3548).
+*10(h)3	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2012 (filed as Exhibit 10(m)12 to the 2011 Form 10-K, File No. 1-3548).
+*10(h)4	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2012 (filed as Exhibit 10(m)13 to the 2011 Form 10-K, File No. 1-3548).
+*10(h)5	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2013 (filed as Exhibit 10(k)14 to the 2012 Form 10-K, File No. 1-3548).
+*10(h)6	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2013 (filed as Exhibit 10(k)15 to the 2012 Form 10-K, File No. 1-3548).
+*10(h)7	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2014 (filed as Exhibit 10(j)14 to the 2013 Form 10-K, File No. 1-3548).
+*10(h)8	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2014 (filed as Exhibit 10(j)15 to the 2013 Form 10-K, File No. 1-3548).
+*10(h)9	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2015 (filed as Exhibit 10(j)16 to the 2014 Form 10-K, File No. 1-3548).
+*10(h)10	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2015 (filed as Exhibit 10(j)17 to the 2014 Form 10-K, File No. 1-3548).
+*10(i)1	—	ALLETE Executive Long-Term Incentive Compensation Plan effective January 1, 2016 (filed November 6, 2015, as Exhibit 99 to Form S-8, File No. 333-207846).
+*10(i)2	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2016 (filed as Exhibit 10(k)3 to the 2015 Form 10-K, File No. 1-3548).
+*10(i)3	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2016 (filed as Exhibit 10(k)2 to the 2015 Form 10-K, File No. 1-3548).
+*10(i)4	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Cash Award Effective 2017 (filed as Exhibit 10(i)4 to the 2016 Form 10-K, File No. 1-3548).
+*10(i)5	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2017 (filed as Exhibit 10(i)5 to the 2016 Form 10-K, File No. 1-3548).
+*10(i)6	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2017 (filed as Exhibit 10(i)6 to the 2016 Form 10-K, File No. 1-3548).
+10(i)7	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2018.
+10(i)8	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2018.
+*10(j)1	—	Amended and Restated ALLETE Non-Employee Director Stock Plan, effective May 15, 2013 (filed as Exhibit 10(a) to the June 30, 2013, Form 10-Q, File No. 1-3548).
+*10(k)1	—	ALLETE Non-Employee Director Compensation Summary effective January 1, 2015 (filed as Exhibit 10(l)5 to the 2014 Form 10-K, File No. 1-3548).
+*10(k)2	—	ALLETE Non-Employee Director Compensation Summary effective January 1, 2017 (filed as Exhibit 10(k)3 to the 2016 Form 10-K, File No. 1-3548).
+*10(l)1	—	Minnesota Power (now ALLETE) Non-Employee Director Compensation Deferral Plan Amended and Restated, effective January 1, 1990 (filed as Exhibit 10(ac) to the 2002 Form 10-K, File No. 1-3548).
+*10(l)2	—	October 2003 Amendment to the Minnesota Power (now ALLETE) Non-Employee Director Compensation Deferral Plan (filed as Exhibit 10(aa)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(l)3	—	January 2005 Amendment to the ALLETE Non-Employee Director Compensation Deferral Plan (filed as Exhibit 10(c) to the March 31, 2005, Form 10-Q, File No. 1-3548).
+*10(l)4	—	October 2006 Amendment to the ALLETE Non-Employee Director Compensation Deferral Plan (filed as Exhibit 10(d) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(l)5	—	July 2012 Amendment to the ALLETE Non-Employee Director Compensation Deferral Plan (filed as Exhibit 10(n)5 to the 2012 Form 10-K, File No. 1-3548).

Exhibit Number		
+*10(m)1	—	ALLETE Non-Employee Director Compensation Deferral Plan II, effective May 1, 2009 (filed as Exhibit 10(a) to the June 30, 2009, Form 10-Q, File No. 1-3548).
+*10(m)2	—	ALLETE Non-Employee Director Compensation Deferral Plan II, as amended and restated, effective July 24, 2012 (filed as Exhibit 10(o)2 to the 2012 Form 10-K, File No. 1-3548).
+*10(n)	—	ALLETE Non-Employee Director Compensation Trust Agreement, as amended and restated, effective December 15, 2012 (filed as Exhibit 10(p)2 to the 2012 Form 10-K, File No. 1-3548).
+*10(o)	—	ALLETE and Affiliated Companies Change in Control Severance Plan, as amended and restated, effective January 19, 2011 (filed as Exhibit 10(q) to the 2010 Form 10-K, File No. 1-3548).
12	—	Computation of Ratios of Earnings to Fixed Charges.
21	—	Subsidiaries of the Registrant.
23	—	Consent of Independent Registered Public Accounting Firm.
31(a)	—	Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)	—	Rule 13a-14(a)/15d-14(a) Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	—	Section 1350 Certification of Annual Report by the Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	—	Mine Safety.
99	—	**ALLETE News Release dated February 15, 2018, announcing earnings for the year ended December 31, 2017. (This exhibit has been furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, except as shall be expressly set forth by specific reference in such filing.)**
101.INS	—	XBRL Instance
101.SCH	—	XBRL Schema
101.CAL	—	XBRL Calculation
101.DEF	—	XBRL Definition
101.LAB	—	XBRL Label
101.PRE	—	XBRL Presentation

Exhibits (Continued)

ALLETE or its subsidiaries are obligors under various long-term debt instruments including, but not limited to, the following:

- $38,995,000 original principal amount, of City of Cohasset, Minnesota, Variable Rate Demand Revenue Refunding Bonds (ALLETE, formerly Minnesota Power & Light Company, Project) Series 1997A ($13,500,000 remaining principal balance);
- $27,800,000 of Collier County Industrial Development Authority, Industrial Development Variable Rate Demand Refunding Revenue Bonds Series 2006;
- $6,370,000 of City of Superior, Wisconsin, Collateralized Utility Revenue Refunding Bonds Series 2007A; and
- $6,130,000 of City of Superior, Wisconsin, Collateralized Utility Revenue Bonds Series 2007B.

Pursuant to Item 601(b)(4)(iii) of Regulation S-K, these long-term debt instruments are not filed as exhibits because the total amount of debt authorized under each of these omitted instruments does not exceed 10 percent of our total consolidated assets. We will furnish copies of these instruments to the SEC upon its request.

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* *Incorporated herein by reference as indicated.*

\+ *Management contract or compensatory plan or arrangement pursuant to Item 15(b).*

Item 16. Form 10-K Summary

None.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ALLETE, Inc.

Dated: February 15, 2018

By /s/ Alan R. Hodnik
Alan R. Hodnik
Chairman, President, Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Alan R. Hodnik Alan R. Hodnik	Chairman, President, Chief Executive Officer and Director (Principal Executive Officer)	February 15, 2018
/s/ Robert J. Adams Robert J. Adams	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 15, 2018
/s/ Steven W. Morris Steven W. Morris	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)	February 15, 2018

Signatures (Continued)

Signature	Title	Date
/s/ Kathryn W. Dindo Kathryn W. Dindo	Director	February 15, 2018
/s/ Sidney W. Emery, Jr. Sidney W. Emery, Jr.	Director	February 15, 2018
/s/ George G. Goldfarb George G. Goldfarb	Director	February 15, 2018
/s/ James S. Haines, Jr. James S. Haines, Jr.	Director	February 15, 2018
/s/ James J. Hoolihan James J. Hoolihan	Director	February 15, 2018
/s/ Heidi E. Jimmerson Heidi E. Jimmerson	Director	February 15, 2018
/s/ Madeleine W. Ludlow Madeleine W. Ludlow	Director	February 15, 2018
/s/ Susan K. Nestegard Susan K. Nestegard	Director	February 15, 2018
/s/ Douglas C. Neve Douglas C. Neve	Director	February 15, 2018
/s/ Robert P. Powers Robert P. Powers	Director	February 15, 2018
/s/ Leonard C. Rodman Leonard C. Rodman	Director	February 15, 2018

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of ALLETE, Inc.:

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of ALLETE, Inc. and its subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of income, comprehensive income, equity and cash flows for each of the three years in the period ended December 31, 2017, including the related notes and schedule of valuation and qualifying accounts and reserves for each of the three years in the period ended December 31, 2017 appearing under Item 15(a)(2) (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Minneapolis, Minnesota
February 15, 2018

We have served as the Company's auditor since 1963.

CONSOLIDATED FINANCIAL STATEMENTS

ALLETE Consolidated Balance Sheet

As of December 31	2017	2016
Millions		
Assets		
Current Assets		
Cash and Cash Equivalents	$98.9	$27.5
Accounts Receivable (Less Allowance of $2.1 and $3.1)	135.1	122.5
Inventories – Net	95.9	104.2
Prepayments and Other	37.6	40.3
Total Current Assets	367.5	294.5
Property, Plant and Equipment – Net	3,822.4	3,741.2
Regulatory Assets	384.7	330.1
Investment in ATC	118.7	135.6
Other Investments	53.1	55.6
Goodwill and Intangible Assets – Net	225.9	213.4
Other Non-Current Assets	107.7	106.5
Total Assets	$5,080.0	$4,876.9
Liabilities and Shareholders' Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$136.3	$74.0
Accrued Taxes	50.0	46.5
Accrued Interest	17.6	17.6
Long-Term Debt Due Within One Year	64.1	187.7
Other	83.2	73.7
Total Current Liabilities	351.2	399.5
Long-Term Debt	1,439.2	1,370.4
Deferred Income Taxes	230.5	554.6
Regulatory Liabilities	532.0	125.8
Defined Benefit Pension and Other Postretirement Benefit Plans	191.8	210.9
Other Non-Current Liabilities	267.1	322.7
Total Liabilities	3,011.8	2,983.9
Commitments, Guarantees and Contingencies (Note 11)		
Shareholders' Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 51.1 and 49.6 Shares Issued and Outstanding	1,401.4	1,295.3
Accumulated Other Comprehensive Loss	(22.6)	(28.2)
Retained Earnings	689.4	625.9
Total Shareholders' Equity	2,068.2	1,893.0
Total Liabilities and Shareholders' Equity	$5,080.0	$4,876.9

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Income

Year Ended December 31	2017	2016	2015
Millions Except Per Share Amounts			
Operating Revenue			
Utility	$1,063.8	$1,000.7	$991.2
Non-utility	355.5	339.0	495.2
Total Operating Revenue	1,419.3	1,339.7	1,486.4
Operating Expenses			
Fuel, Purchased Power and Gas – Utility	396.9	339.9	336.0
Transmission Services – Utility	71.2	65.2	54.1
Cost of Sales – Non-utility	147.8	137.7	294.4
Operating and Maintenance	339.9	334.1	333.5
Depreciation and Amortization	177.5	195.8	170.0
Taxes Other than Income Taxes	56.9	53.8	51.4
Other	(0.7)	(10.3)	36.3
Total Operating Expenses	1,189.5	1,116.2	1,275.7
Operating Income	229.8	223.5	210.7
Other Income (Expense)			
Interest Expense	(67.8)	(70.3)	(64.9)
Equity Earnings in ATC	22.5	18.5	16.3
Other	2.4	3.9	4.7
Total Other Expense	(42.9)	(47.9)	(43.9)
Income Before Non-Controlling Interest and Income Taxes	186.9	175.6	166.8
Income Tax Expense	14.7	19.8	25.3
Net Income	172.2	155.8	141.5
Less: Non-Controlling Interest in Subsidiaries	—	0.5	0.4
Net Income Attributable to ALLETE	$172.2	$155.3	$141.1
Average Shares of Common Stock			
Basic	50.8	49.3	48.3
Diluted	51.0	49.5	48.4
Basic Earnings Per Share of Common Stock	$3.39	$3.15	$2.92
Diluted Earnings Per Share of Common Stock	$3.38	$3.14	$2.92
Dividends Per Share of Common Stock	$2.14	$2.08	$2.02

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Comprehensive Income

Year Ended December 31	2017	2016	2015
Millions			
Net Income	$172.2	$155.8	$141.5
Other Comprehensive Income (Loss)			
Unrealized Gain (Loss) on Securities			
Net of Income Tax Expense (Benefit) of $0.7, $(0.2) and $(0.3)	0.9	(0.2)	(0.5)
Unrealized Gain on Derivatives			
Net of Income Tax Expense of $–, $– and $0.1	—	—	0.1
Defined Benefit Pension and Other Postretirement Benefit Plans			
Net of Income Tax Expense (Benefit) of $2.2, $(2.4) and $(2.2)	4.7	(3.5)	(3.0)
Total Other Comprehensive Income (Loss)	5.6	(3.7)	(3.4)
Total Comprehensive Income	177.8	152.1	138.1
Less: Non-Controlling Interest in Subsidiaries	—	0.5	0.4
Total Comprehensive Income Attributable to ALLETE	$177.8	$151.6	$137.7

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Cash Flows

Year Ended December 31	2017	2016	2015
Millions			
Operating Activities			
Net Income	$172.2	$155.8	$141.5
AFUDC – Equity	(1.2)	(2.1)	(3.3)
Income from Equity Investments – Net of Dividends	(3.2)	(5.7)	(1.8)
Impairment of Real Estate	—	—	36.3
Impairment of Goodwill	—	3.3	—
Change in Fair Value of Contingent Consideration	(0.7)	(13.6)	—
Deferred Fuel Adjustment Clause Charge	19.5	—	—
Loss (Gain) on Sales of Investments and Property, Plant and Equipment	0.4	(6.0)	(0.2)
Depreciation Expense	171.9	190.6	165.9
Amortization of PSAs	(23.6)	(22.3)	(23.2)
Amortization of Other Intangible Assets and Other Assets	10.2	10.3	5.6
Deferred Income Tax Expense	14.4	19.4	25.1
Share-Based and ESOP Compensation Expense	6.6	5.1	11.6
Defined Benefit Pension and Other Postretirement Benefit Expense	10.1	4.6	15.4
Bad Debt Expense	0.8	4.1	1.6
Provision for Interim Rate Refund	32.3	—	—
Changes in Operating Assets and Liabilities			
Accounts Receivable	(8.0)	(4.7)	1.1
Inventories	11.9	13.3	(22.1)
Prepayments and Other	(5.3)	(6.9)	3.7
Accounts Payable	(7.5)	6.5	(19.3)
Other Current Liabilities	1.8	(13.8)	5.1
Cash Contributions to Defined Benefit Pension Plans	(1.7)	(6.3)	—
Changes in Regulatory and Other Non-Current Assets	33.7	(10.7)	0.6
Changes in Regulatory and Other Non-Current Liabilities	(31.7)	11.1	(3.5)
Cash from Operating Activities	402.9	332.0	340.1
Investing Activities			
Proceeds from Sale of Available-for-sale Securities	10.1	9.0	1.7
Payments for Purchase of Available-for-sale Securities	(8.6)	(9.4)	(2.3)
Acquisitions of Subsidiaries – Net of Cash Acquired	(18.5)	(5.9)	(333.3)
Investment in ATC	(7.8)	(5.4)	(1.6)
Changes to Other Investments	3.0	4.4	3.1
Additions to Property, Plant and Equipment	(208.5)	(265.6)	(286.8)
Proceeds from Sale of Property, Plant and Equipment	1.3	0.7	0.4
Changes in Restricted Cash	—	(4.0)	—
Cash for Investing Activities	(229.0)	(276.2)	(618.8)
Financing Activities			
Proceeds from Issuance of Common Stock	86.0	30.9	161.2
Proceeds from Issuance of Long-Term Debt	131.5	4.8	324.5
Changes in Restricted Cash	(0.4)	7.0	8.5
Changes in Notes Payable	—	(1.6)	(2.1)
Repayments of Long-Term Debt	(189.6)	(54.8)	(160.2)
Acquisition of Non-Controlling Interest	—	(8.0)	—
Acquisition-Related Contingent Consideration Payments	(19.7)	(0.9)	—
Dividends on Common Stock	(108.7)	(102.7)	(97.9)
Other Financing Activities	(1.6)	—	(4.1)
Cash from (for) Financing Activities	(102.5)	(125.3)	229.9
Change in Cash and Cash Equivalents	71.4	(69.5)	(48.8)

Cash and Cash Equivalents at Beginning of Period	27.5	97.0	145.8
Cash and Cash Equivalents at End of Period	$98.9	$27.5	$97.0

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Equity

	Total Equity	Retained Earnings	Accumulated Other Comprehensive Loss	Unearned ESOP Shares	Common Stock	Non-Controlling Interest in Subsidiaries
Millions						
Balance as of December 31, 2014	$1,611.2	$530.1	$(21.1)	$(7.2)	$1,107.6	$1.8
Comprehensive Income						
Net Income	141.5	141.1	—	—	—	0.4
Other Comprehensive Income – Net of Tax						
Unrealized Loss on Securities	(0.5)	—	(0.5)	—	—	—
Unrealized Gain on Derivatives	0.1	—	0.1	—	—	—
Defined Benefit Pension and Other Postretirement Plans	(3.0)	—	(3.0)	—	—	—
Total Comprehensive Income	138.1					
Common Stock Issued	163.8	—	—	—	163.8	—
Dividends Declared	(97.9)	(97.9)	—	—	—	—
ESOP Shares Earned	7.2	—	—	7.2	—	—
Balance as of December 31, 2015	1,822.4	573.3	(24.5)	—	1,271.4	2.2
Comprehensive Income						
Net Income	155.8	155.3	—	—	—	0.5
Other Comprehensive Income – Net of Tax						
Unrealized Loss on Securities	(0.2)	—	(0.2)	—	—	—
Defined Benefit Pension and Other Postretirement Plans	(3.5)	—	(3.5)	—	—	—
Total Comprehensive Income	152.1					
Common Stock Issued	35.9	—	—	—	35.9	—
Common Stock Retired	(8.0)	—	—	—	(8.0)	—
Dividends Declared	(102.7)	(102.7)	—	—	—	—
Acquisition of Non-Controlling Interest	(6.7)	—	—	—	(4.0)	(2.7)
Balance as of December 31, 2016	1,893.0	625.9	(28.2)	—	1,295.3	—
Comprehensive Income						
Net Income	172.2	172.2	—	—	—	—
Other Comprehensive Income – Net of Tax						
Unrealized Gain on Securities	0.9	—	0.9	—	—	—
Defined Benefit Pension and Other Postretirement Plans	4.7	—	4.7	—	—	—
Total Comprehensive Income	177.8					
Common Stock Issued	106.1	—	—	—	106.1	—
Dividends Declared	(108.7)	(108.7)	—	—	—	—
Balance as of December 31, 2017	$2,068.2	$689.4	$(22.6)	—	$1,401.4	—

The accompanying notes are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Preparation. References in this report to "we," "us," and "our" are to ALLETE and its subsidiaries, collectively. We prepare our financial statements in conformity with GAAP. These principles require management to make informed judgments, best estimates, and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses. Actual results could differ from those estimates.

Subsequent Events. The Company performed an evaluation of subsequent events for potential recognition and disclosure through the time of the financial statements issuance.

Principles of Consolidation. Our Consolidated Financial Statements include the accounts of ALLETE and all of our majority-owned subsidiary companies. All material intercompany balances and transactions have been eliminated in consolidation.

Business Segments. We present three reportable segments: Regulated Operations, ALLETE Clean Energy and U.S. Water Services. Our segments were determined in accordance with the guidance on segment reporting. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment.

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in portions of Wisconsin, Michigan, Minnesota and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 145,000 retail customers. Minnesota Power also has 16 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a wholesale customer of Minnesota Power. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 13,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities .

ALLETE Clean Energy focuses on developing, acquiring, and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates, in four states, approximately 535 MW of nameplate capacity wind energy generation that is contracted under PSAs of various durations. ALLETE Clean Energy also engages in the development of wind energy facilities to operate under long-term PSAs or for sale to others upon completion.

U.S. Water Services provides integrated water management for industry by combining chemical, equipment, engineering and service for customized solutions to reduce water and energy usage, and improve efficiency.

Corporate and Other is comprised of BNI Energy, ALLETE Properties, other business development and corporate expenditures, unallocated interest expense, a small amount of non-rate base generation, approximately 5,000 acres of land in Minnesota, and earnings on cash and investments.

BNI Energy mines and sells lignite coal to two North Dakota mine-mouth generating units, one of which is Square Butte. In 2017 , Square Butte supplied 50 percent (227.5 MW) of its output to Minnesota Power under long-term contracts. (See Note 11. Commitments, Guarantees and Contingencies.)

ALLETE Properties represents our legacy Florida real estate investment. Our strategy related to the real estate assets of ALLETE Properties is to sell individual parcels over time, but incorporates the possibility of a bulk sale of our entire real estate portfolio. Proceeds from a bulk sale would be strategically deployed to support growth in ALLETE Clean Energy and U.S. Water Services, collectively our energy infrastructure and related services businesses. ALLETE Properties will continue to maintain key entitlements and infrastructure without making additional investments or acquisitions. (See Note 8. Investments.)

Cash and Cash Equivalents. We consider all investments purchased with original maturities of three months or less to be cash equivalents.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Supplemental Statement of Cash Flow Information.

Consolidated Statement of Cash Flows

Year Ended December 31	2017	2016	2015
Millions			
Cash Paid During the Period for Interest – Net of Amounts Capitalized	$64.5	$68.2	$59.0
Cash Paid During the Period for Income Taxes	$0.4	$0.5	$0.4
Remeasurement of Deferred Income Taxes Resulting from the TCJA			
Increase in Regulatory Assets	$80.9	—	—
Decrease in Investment in ATC	$(27.9)	—	—
Decrease in Deferred Income Taxes	$(353.6)	—	—
Increase in Regulatory Liabilities	$393.6	—	—
Noncash Investing and Financing Activities			
Increase (Decrease) in Accounts Payable for Capital Additions to Property, Plant and Equipment	$67.2	$(22.0)	$(40.6)
Capitalized Asset Retirement Costs	$(15.6)	$3.7	$12.4
Camp Ripley Solar Financing	—	$15.0	—
AFUDC–Equity	$1.2	$2.1	$3.3
ALLETE Common Stock Contributed to Pension Plans	$13.5	—	—
Contingent Consideration	—	—	$35.7
ALLETE Common Stock Received for Land Inventory	—	$8.0	—
Long-Term Finance Receivable for Land Inventory	—	$12.0	—

Accounts Receivable. Accounts receivable are reported on the Consolidated Balance Sheet net of an allowance for doubtful accounts. The allowance is based on our evaluation of the receivable portfolio under current conditions, overall portfolio quality, review of specific situations and such other factors that, in our judgment, deserve recognition in estimating losses.

Accounts Receivable

As of December 31	2017	2016
Millions		
Trade Accounts Receivable		
Billed	$112.6	$106.5
Unbilled	24.6	19.1
Less: Allowance for Doubtful Accounts	2.1	3.1
Total Accounts Receivable	$135.1	$122.5

Concentration of Credit Risk. We are subject to concentration of credit risk primarily as a result of accounts receivable. Minnesota Power sells electricity to nine Large Power Customers. Receivables from these customers totaled $13.8 million as of December 31, 2017 ($9.5 million as of December 31, 2016). Minnesota Power does not obtain collateral to support utility receivables, but monitors the credit standing of major customers. In addition, Minnesota Power, as permitted by the MPUC, requires its taconite-producing Large Power Customers to pay weekly for electric usage based on monthly energy usage estimates, which allows us to closely manage collection of amounts due. One of these customers accounted for 10 percent of consolidated operating revenue in 2017 (8 percent in 2016 and in 2015).

Long-Term Finance Receivables. Long-term finance receivables relating to our real estate operations are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts. We assess delinquent finance receivables by comparing the balance of such receivables to the estimated fair value of the collateralized property. If the fair value of the property is less than the finance receivable, we record a reserve for the difference. We estimate fair value based on recent property tax assessed values or current appraisals.

Available-for-Sale Securities. Available-for-sale securities are recorded at fair value with unrealized gains and losses included in accumulated other comprehensive income (loss), net of tax. Unrealized losses that are other than temporary are recognized in earnings. We use the specific identification method as the basis for determining the cost of securities sold. Our policy is to review available-for-sale securities for other than temporary impairment on a quarterly basis by assessing such factors as share price trends and the impact of overall market conditions. (See *New Accounting Pronouncements* and Note 8. Investments.)

Inventories – Net. Inventories are stated at the lower of cost or net realizable value. Inventories in our Regulated Operations and ALLETE Clean Energy segments are carried at an average cost or first-in, first-out basis. Inventories in our U.S. Water Services segment and Corporate and Other operations are carried at an average cost, first-in, first-out or specific identification basis.

Inventories – Net

As of December 31	2017	2016
Millions		
Fuel *(a)*	$34.8	$43.9
Materials and Supplies	46.5	48.7
Raw Materials	2.8	2.9
Work in Progress	4.2	1.0
Finished Goods	8.3	8.6
Reserve for Obsolescence	(0.7)	(0.9)
Total Inventories – Net	$95.9	$104.2

(a) Fuel consists primarily of coal inventory at Minnesota Power.

Prepayments and Other Current Assets

As of December 31	2017	2016
Millions		
Deferred Fuel Adjustment Clause *(a)*	—	$18.6
Restricted Cash *(b)*	$2.6	2.2
Other	35.0	19.5
Total Prepayments and Other Current Assets	$37.6	$40.3

(a) At a hearing on January 18, 2018, the MPUC disallowed recovery of Minnesota Power's regulatory asset for deferred fuel adjustment clause costs resulting in a $19.5 million pre-tax charge to Fuel, Purchased Power and Gas – Utility in 2017.

(b) Restricted Cash includes collateral deposits required under an ALLETE Clean Energy loan agreement and collateral deposits required for U.S. Water Services' standby letters of credit.

Property, Plant and Equipment. Property, plant and equipment are recorded at original cost and are reported on the Consolidated Balance Sheet net of accumulated depreciation. Expenditures for additions, significant replacements, improvements and major plant overhauls are capitalized; maintenance and repair costs are expensed as incurred. Gains or losses on property, plant and equipment in our U.S. Water Services segment and Corporate and Other operations are recognized when they are retired or otherwise disposed. When property, plant and equipment in our Regulated Operations and ALLETE Clean Energy segments are retired or otherwise disposed, no gain or loss is recognized in accordance with the accounting standards for component depreciation except for certain circumstances where the retirement is unforeseen or unexpected. Our Regulated Operations capitalize AFUDC, which includes both an interest and equity component. AFUDC represents the cost of both debt and equity funds used to finance utility plant additions during construction periods. AFUDC amounts capitalized are included in rate base and are recovered from customers as the related property is depreciated. Upon MPUC approval of cost recovery, the recognition of AFUDC ceases. (See Note 2. Property, Plant and Equipment.)

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
Property, Plant and Equipment (Continued)

We believe that long-standing ratemaking practices approved by applicable state and federal regulatory commissions allow for the recovery of the remaining book value of retired plant assets. In 2015, Minnesota Power retired Taconite Harbor Unit 3 and converted Laskin to operate on natural gas which were actions included in Minnesota Power's MPUC-approved 2013 IRP. In a July 2016 order, the MPUC approved Minnesota Power's 2015 IRP with modifications. The 2015 IRP contains steps in Minnesota Power's *EnergyForward* plan including the economic idling of Taconite Harbor Units 1 and 2 in September 2016, and the ceasing of coal-fired operations at Taconite Harbor in 2020. (See Note 4. Regulatory Matters.) The MPUC order for the 2015 IRP also directed Minnesota Power to retire Boswell Units 1 and 2 no later than 2022. In October 2016, Minnesota Power announced that Boswell Units 1 and 2 will be retired in 2018. We do not expect to record any impairment charge as a result of the retirement of Taconite Harbor Unit 3, the ceasing of coal-fired operations at Taconite Harbor Units 1 and 2, or the conversion of Laskin to operate on natural gas. In addition, we expect to be able to continue depreciating these assets for at least their established remaining useful lives; however, we are unable to predict the impact of regulatory outcomes resulting in changes to their established remaining useful lives.

Impairment of Long-Lived Assets. We review our long-lived assets, which include the legacy real estate assets of ALLETE Properties, for indicators of impairment in accordance with the accounting standards for property, plant and equipment on a quarterly basis. Land inventory is accounted for as held for use and is recorded at cost, unless the carrying value is determined not to be recoverable in accordance with the accounting standards for property, plant and equipment, in which case the land inventory is written down to estimated fair value.

In accordance with the accounting standards for property, plant and equipment, if indicators of impairment exist, we test our long-lived assets for recoverability by comparing the carrying amount of the asset to the undiscounted future net cash flows expected to be generated by the asset. Cash flows are assessed at the lowest level of identifiable cash flows. The undiscounted future net cash flows are impacted by trends and factors known to us at the time they are calculated and our expectations related to: management's best estimate of future sales prices; holding period and timing of sales; method of disposition; and future expenditures necessary to maintain the operations.

Real Estate Assets. In recent years, market conditions for real estate in Florida have required us to review our land inventories for impairment. In 2015, the Company reevaluated its strategy related to the real estate assets of ALLETE Properties in response to market conditions and transaction activity. The revised strategy incorporated the possibility of a bulk sale of its entire portfolio. Proceeds from a bulk sale would be strategically deployed to support growth in ALLETE Clean Energy and U.S. Water Services, collectively our Energy Infrastructure and Related Services businesses. ALLETE Properties also continues to pursue sales of individual parcels over time. ALLETE Properties will continue to maintain key entitlements and infrastructure without making additional investments or acquisitions.

In connection with implementing the revised strategy, management evaluated its impairment analysis for its real estate assets using updated assumptions to determine estimated future net cash flows on an undiscounted basis. Estimated fair values were based upon current market data and pricing for individual parcels. Our impairment analysis incorporates a probability-weighted approach considering the alternative courses of sales noted above.

Based on the results of the 2015 undiscounted cash flow analysis, the undiscounted future net cash flows were not adequate to recover the carrying value of the real estate assets leading to an adjustment of carrying value to estimated fair value. Estimated fair value was derived using Level 3 inputs, including current market interest in the property for a bulk sale of its entire portfolio, and discounted cash flow analysis of estimated selling price for sales over time. As a result, a non-cash impairment charge of $36.3 million was recorded in 2015 to reduce the carrying value of the real estate to its estimated fair value.

In 2017 and 2016, our qualitative assessments indicated that the cash flows were adequate to recover the carrying value of ALLETE Properties real estate assets. As a result, no impairment was recorded in 2017 or 2016.

Derivatives. ALLETE is exposed to certain risks relating to its business operations that can be managed through the use of derivative instruments. ALLETE may enter into derivative instruments to manage those risks including interest rate risk related to certain variable-rate borrowings.

Accounting for Stock-Based Compensation. We apply the fair value recognition guidance for share-based payments. Under this guidance, we recognize stock-based compensation expense for all share-based payments granted, net of an estimated forfeiture rate. (See Note 16. Employee Stock and Incentive Plans.)

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Goodwill and Intangible Assets.

Goodwill. Goodwill is the excess of the purchase price (consideration transferred) over the estimated fair value of net assets of acquired businesses. In accordance with GAAP, goodwill is not amortized. Goodwill is assessed annually in the fourth quarter for impairment and whenever an event occurs or circumstances change that would indicate the carrying amount may be impaired. Impairment testing for goodwill is done at the reporting unit level.

As part of the 2016 annual impairment analysis, the Company recognized a non-cash impairment charge of $3.3 million for ALLETE Clean Energy's goodwill primarily related to the acquisition of Storm Lake II in 2014 . The charge, which is presented within Operating Expenses – Other in the Consolidated Statement of Income, eliminated all recognized goodwill for the ALLETE Clean Energy reporting unit.

As of the date of our annual goodwill impairment testing in 2017 , the U.S. Water Services reporting unit had positive equity and the Company elected to bypass the qualitative assessment of goodwill for impairment, proceeding directly to the two-step impairment test. In performing Step 1 of the impairment test, we compared the fair value of the reporting unit to its carrying value including goodwill. If the carrying value including goodwill were to exceed the fair value of a reporting unit, Step 2 of the impairment test would be performed. Step 2 of the impairment test requires the carrying value of goodwill to be reduced to its fair value, if lower, as of the test date.

U.S. Water Services . For Step 1 of the impairment test, we estimated the reporting unit's fair value using standard valuation techniques, including techniques which use estimates of projected future results and cash flows to be generated by the reporting unit. Such techniques generally include a terminal value that utilizes a growth rate on debt-free cash flows. These cash flow valuations involve a number of estimates that require broad assumptions and significant judgment by management regarding future performance. Our annual impairment test in 2017 indicated that the estimated fair value of U.S. Water Services exceeded its carrying value, and therefore no impairment existed (none in 2016 or in 2015). The fair value of the reporting unit was determined using a discounted cash flow model, using significant assumptions which included a discount rate of 10.75 percent , cash flow forecasts through 2022, annual revenue growth rates ranging from 7 percent to 9 percent, excluding 13 percent of revenue growth in 2018 related to the year over year impact of the acquisition of Tonka Water, and a terminal growth rate of 4.0 percent. Forecasted annual revenue growth assumes an increase in market share and growth in the industry.

Intangible Assets. Intangible assets include customer relationships, patents, non-compete agreements, land easements, trademarks and trade names. Intangible assets with definite lives consist of customer relationships, which are amortized using an attrition model, and patents, non-compete agreements, land easements and certain trade names, which are amortized on a straight-line basis with estimated remaining useful lives ranging from approximately 1 year to approximately 20 years. We review definite-lived intangible assets for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Indefinite-lived intangible assets consist of trademarks and certain trade names, which are tested for impairment annually in the fourth quarter and whenever an event occurs or circumstances change that would indicate that the carrying amount may be impaired. Impairment is calculated as the excess of the asset's carrying amount over its fair value. Fair value is generally determined using a discounted cash flow analysis. Our annual impairment test in 2017 indicated that the estimated fair value of trademarks and trade names exceeded the asset carrying values. As a result, no impairment existed in 2017 (none in 2016 or in 2015).

Other Non-Current Assets

As of December 31	2017	2016
Millions		
Contract Payment *(a)*	$27.5	$29.6
Finance Receivable *(b)*	11.0	11.5
Restricted Cash *(c)*	8.6	8.6
Other	60.6	56.8
Total Other Non-Current Assets	$107.7	$106.5

(a) Contract Payment includes a payment made to Cliffs as part of a long-term PSA between Minnesota Power and Silver Bay Power. The contract payment is being amortized over the term of the PSA. (See Note 11. Commitments, Guarantees and Contingencies.)

(b) In 2016, ALLETE Properties sold its Ormond Crossings project and Lake Swamp wetland mitigation bank for consideration of approximately $21 million . The consideration included a down payment in the form of 0.1 million shares of ALLETE common stock with a value of $8.0 million . The remaining purchase price will be paid under the terms of a finance receivable due over a five -year period which bears interest at market rates and is collateralized by the property sold.

(c) Restricted Cash includes collateral deposits required under an ALLETE Clean Energy loan agreement and PSAs, and deposits from SWL&P customers in aid of future capital expenditures.

Other Current Liabilities

As of December 31	2017	2016
Millions		
PSAs	$24.5	$24.6
Other	58.7	49.1
Total Other Current Liabilities	$83.2	$73.7

Other Non-Current Liabilities

As of December 31	2017	2016
Millions		
Asset Retirement Obligation	$122.7	$136.6
PSAs	89.5	113.8
Contingent Consideration *(a)*	5.4	25.0
Other	49.5	47.3
Total Other Non-Current Liabilities	$267.1	$322.7

(a) Contingent Consideration relates to the estimated fair value of the earnings-based payment resulting from the U.S. Water Services acquisition. (See Note 6. Acquisitions and Note 9. Fair Value.)

Environmental Liabilities. We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated based on current law and existing technologies. Accruals are adjusted as assessment and remediation efforts progress, or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in the Consolidated Balance Sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are expensed unless recoverable in rates from customers. (See Note 11. Commitments, Guarantees and Contingencies.)

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Revenue Recognition.

Regulated Operations utility rates are under the jurisdiction of Minnesota, Wisconsin and federal regulatory authorities. Customers are billed on a cycle basis. Revenue is accrued for services provided but not yet billed. Regulated utility electric rates include adjustment clauses that: (1) bill or credit customers for fuel and purchased energy costs above or below the base levels in rate schedules; (2) bill retail customers for the recovery of conservation improvement program expenditures not collected in base rates; and (3) bill customers for the recovery of certain transmission, renewable, and environmental improvement expenditures. Previously, fuel and purchased power expense was deferred to match the period in which the revenue for fuel and purchased power expense was billed to customers with the deferred fuel costs recognized as a regulatory asset. At a hearing on January 18, 2018, the MPUC disallowed recovery of Minnesota Power's regulatory asset for deferred fuel adjustment clause costs due to the anticipated adoption of a forward-looking fuel adjustment clause methodology resulting in a $19.5 million pre-tax charge to Fuel, Purchased Power and Gas – Utility in 2017. As a result of the MPUC hearing, fuel and purchased power costs above or below the base levels in rate schedules are no longer deferred.

Revenue from cost recovery riders (transmission, renewable and environmental improvement) is accounted for in accordance with GAAP for alternative revenue programs. These standards allow for recognizing revenue under an alternative revenue program if the program is established by an order from the utility's regulatory authority, the order allows automatic adjustment of future rates, the amount of the revenue recognized is objectively determinable and probable of recovery, and the revenue will be collected within 24 months following the end of the annual period in which it is recognized. Revenue recognized using the alternative revenue program guidance is included in Operating Revenue – Utility on the Consolidated Statement of Income and Regulatory Assets on the Consolidated Balance Sheet until it is subsequently collected from customers.

Minnesota Power participates in MISO. MISO transactions are accounted for on a net hourly basis in each of the day-ahead and real-time markets. Minnesota Power records net sales in Operating Revenue – Utility and net purchases in Fuel, Purchased Power and Gas – Utility expense on the Consolidated Statement of Income.

ALLETE Clean Energy recognizes revenue from the sale of energy from PSAs under various durations. Revenue is recognized when delivered to an agreed upon point or production is curtailed at the request of its customers at specified prices. As part of its acquisitions of wind energy facilities, ALLETE Clean Energy has assumed various PSAs that were above or below estimated market prices at the time of acquisition and amortizes the resulting differences between contract prices and estimated market prices to Operating Revenue – Non-utility on the Consolidated Statement of Income. In 2017 , we recognized $23.6 million of non-cash revenue amortization relating to the difference between contract prices and estimated market prices as an increase in Operating Revenue – Non-utility ($22.3 million in 2016 ; $23.2 million in 2015). Revenue from the construction and sale of wind energy facilities to others will be recognized at a point in time, or over time, as performance obligations are satisfied based on the terms of each specific agreement.

U.S. Water Services recognizes revenue from the sale of products when the earnings process is complete. This generally occurs when products are shipped to the customer in accordance with the contract or purchase order, ownership and risk of loss have passed to the customer, collectibility is reasonably assured, and pricing is fixed and determinable. Revenue from services is recognized as the services are performed.

Corporate and Other

BNI Energy recognizes coal sales when delivered at the cost of production plus a specified profit per ton of coal delivered.

ALLETE Properties records full profit recognition on sales of real estate upon closing, provided that cash collections are at least 20 percent of the contract price and the other requirements under the guidance for sales of real estate are met. Certain contracts with customers allow us to receive participation revenue from land sales to third parties if various formula-based criteria are achieved.

Operating Expenses – Other

Year Ended December 31	2017	2016	2015
Millions			
Impairment of Real Estate *(a)*	—	—	$36.3
Impairment of Goodwill *(b)*	—	$3.3	—
Change in Fair Value of Contingent Consideration *(c)*	$(0.7)	(13.6)	—
Total Operating Expenses – Other	$(0.7)	$(10.3)	$36.3

(a) See Impairment of Long-Lived Assets.
(b) See Goodwill and Intangible Assets.
(c) See Note 9. Fair Value.

Unamortized Discount and Premium on Debt. Discount and premium on debt are deferred and amortized over the terms of the related debt instruments using a method which approximates the effective interest method.

Income Taxes. ALLETE and its subsidiaries file a consolidated federal income tax return as well as combined and separate state income tax returns. We account for income taxes using the liability method in accordance with GAAP for income taxes. Under the liability method, deferred income tax assets and liabilities are established for all temporary differences in the book and tax basis of assets and liabilities, based upon enacted tax laws and rates applicable to the periods in which the taxes become payable.

Due to the effects of regulation on Minnesota Power and SWL&P, certain adjustments made to deferred income taxes are, in turn, recorded as regulatory assets or liabilities. Federal investment tax credits have been recorded as deferred credits and are being amortized to income tax expense over the service lives of the related property. In accordance with GAAP for uncertainty in income taxes, we are required to recognize in our financial statements the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained on audit, based solely on the technical merits of the position as of the reporting date. The term "more-likely-than-not" means more than 50 percent likely. (See Note 13. Income Tax Expense.)

Tax Cuts and Jobs Act of 2017 . On December 22, 2017, the TCJA was enacted into law. The TCJA has significantly changed the U.S. Internal Revenue Code (IRC) and the taxation of corporations. The more significant provisions that impact our Company include a reduction in the corporate federal income tax rate from 35 percent to 21 percent , and provisions related to our regulated utilities which generally allow for the continued deductibility of interest expense, the elimination of full expensing for property acquired after September 27, 2017, and the continuation of normalization requirements for accelerated tax depreciation taken by regulated utilities. The TCJA allows for full expensing for property and imposes an interest expense limitation on non-regulated operations. The interest expense limitation is not expected to have a material impact on the Company.

Under ASC 740, the tax effects of changes in tax laws must be recognized in the period in which the law is enacted. ASC 740 requires deferred income tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. Thus, as of the date of enactment, the Company's deferred income tax assets and liabilities were remeasured based upon the new tax rate. For our Regulated Operations segment, the change in deferred income taxes was recorded as regulatory assets, regulatory liabilities and a change to our investment in ATC. The benefits of the TCJA for Minnesota Power and SWL&P are expected to be passed back to customers over time primarily based upon the normalization provisions of the IRC over the life of the related property, plant and equipment with the remainder passed back based upon the determinations of regulatory authorities. The decrease in our investment in ATC is expected to be amortized into earnings over time. For our ALLETE Clean Energy and U.S. Water Services segments as well as our Corporate and Other businesses, the change in deferred income taxes is recorded in income tax expense on the Consolidated Statement of Income.

On December 22, 2017, the SEC staff issued guidance in Staff Accounting Bulletin 118 (SAB 118) which clarifies accounting for income taxes under ASC 740 if information is not yet available or complete, and provides for up to a one year period in which to complete the required analyses and accounting (the measurement period). SAB 118 describes three scenarios associated with a company's status of accounting for the TCJA: (1) a company is complete with its accounting for certain effects, (2) a company is able to determine a reasonable estimate for certain effects and records that estimate as a provisional amount, or (3) a company is not able to determine a reasonable estimate and therefore continues to apply ASC 740, based on the provisions of the tax laws that were in effect immediately prior to the TCJA being enacted.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
Income Taxes (Continued)

The Company has made a provisional estimate for the measurement and accounting of the effects of the TCJA, which have been reflected in the Consolidated Financial Statements as of December 31, 2017. The measurement and accounting of the effects of the TCJA resulted in a decrease to Income Tax Expense of $13.0 million for the year ended December 31, 2017, as well as a decrease to Deferred Income Taxes of $353.6 million , a decrease to Investment in ATC of $27.9 million , an increase to Regulatory Assets of $80.9 million and an increase to Regulatory Liabilities of $393.6 million as of December 31, 2017. The provisional amounts incorporate assumptions made based upon the Company's current interpretation of the TCJA, and may change as the Company receives additional clarification and implementation guidance. Any adjustments recorded to the provisional amounts in 2018 will be included in income from operations as an adjustment to income tax expense.

As provided for under SAB 118, the Company has not estimated the impact for items for which it cannot predict, such as guidance that has not yet been provided, or for which federal or state regulatory treatment is still uncertain. The determination of the impact of the income tax effects of these types of items will occur when more information is available to the Company.

Excise Taxes. We collect excise taxes from our customers levied by government entities. These taxes are stated separately on the billing to the customer and recorded as a liability to be remitted to the government entity. We account for the collection and payment of these taxes on a net basis.

Purchase Accounting. In accordance with the authoritative accounting guidance, the purchase price of an acquired business is generally allocated to the assets acquired and liabilities assumed at their estimated fair values on the date of acquisition. Any unallocated purchase price amount is recognized as goodwill on the Consolidated Balance Sheet if it exceeds the estimated fair value and as a bargain purchase gain on the Consolidated Income Statement if it is below the estimated fair value. Determining the fair value of assets acquired and liabilities assumed requires management's judgment, and the utilization of independent valuation experts as well as the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items. The judgments made in the determination of the estimated fair value assigned to the assets acquired and liabilities assumed, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. (See Note 6. Acquisitions.)

New Accounting Pronouncements.

Recently Adopted Pronouncements

Simplifying the Measurement of Inventory. In 2015, the FASB issued an accounting standards update which requires entities that measure inventory using the first-in, first-out or average cost methods to measure inventory at the lower of cost or net realizable value. Net realizable value is defined as estimated selling price in the ordinary course of business less reasonably predictable costs of completion, disposal and transportation. This accounting guidance was adopted in the first quarter of 2017 and did not have a material impact on our Consolidated Financial Statements.

Improvements to Employee Share-Based Payment Accounting. In March 2016, the FASB issued guidance to simplify the accounting for share-based payment transactions by requiring all excess tax benefits and deficiencies to be recognized in income tax expense or benefit in earnings, thus eliminating the requirement to classify the excess tax benefit and deficiencies as additional paid-in capital. Under the new guidance, an entity makes an accounting policy election to either estimate the expected forfeiture awards or account for forfeitures as they occur. This accounting guidance was adopted in the first quarter of 2017. The adoption of this guidance is expected to result in a less than $1 million impact to income tax expense (benefit) annually.

Clarifying the Definition of a Business. In January 2017, the FASB issued clarifying guidance on the definition of a business and provided additional guidance to assist with evaluating whether transactions are to be accounted for as an acquisition or disposal of a group of assets or a business. The clarifying guidance will also impact other areas including the accounting for goodwill and consolidation. This accounting guidance was adopted in the first quarter of 2017 and did not have an impact on our Consolidated Financial Statements.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
New Accounting Pronouncements (Continued)

Stock Compensation: Scope of Modification Accounting. In May 2017, the FASB issued additional clarifying guidance regarding circumstances where changes to the terms or conditions of share-based payment awards require an entity to apply modification accounting under ASC 718. The guidance provides specific situations that would be excluded from effects of a modification including if the fair value, vesting conditions, and classification are the same before and after modification. The amendments in this update will be applied prospectively to awards modified on or after adoption. This accounting guidance was adopted by the Company in the second quarter of 2017 and did not have an impact on our Consolidated Financial Statements.

Recently Issued Pronouncements

Simplifying the Test for Goodwill Impairment . In January 2017, the FASB issued updated guidance which simplifies the measurement of goodwill impairment by removing step two of the goodwill impairment test that requires the determination of the fair value of individual assets and liabilities of a reporting unit. The updated guidance requires goodwill impairment to be measured as the amount by which a reporting unit's carrying value exceeds its fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. This guidance is effective for the Company beginning in the first quarter of 2020, with early adoption permitted on a prospective basis.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. In March 2017, the FASB issued guidance to improve the presentation of net periodic pension and postretirement benefit costs. Under the revised guidance of ASC 715, an entity shall present the service cost component of the net periodic benefit cost in the same income statement line as other employee compensation costs arising from services rendered during the period. The guidance also allows only the service cost component of the periodic cost to be eligible for capitalization. The standard will be applied retrospectively for income statement presentation, and prospectively for capitalization of service cost components. We do not expect there to be a material impact on the Consolidated Financial Statements with the adoption of the updated guidance which is effective for the Company beginning in the first quarter of 2018.

Revenue from Contracts with Customers. In 2014, the FASB issued amended revenue recognition guidance that clarifies the principles for recognizing revenue from contracts with customers by providing a single comprehensive model to determine the measurement of revenue and timing of recognition. The guidance requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. The guidance also requires expanded disclosures relating to the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. Additionally, qualitative and quantitative disclosures are required regarding customer contracts, significant judgments and changes in judgments, and assets recognized from the costs to obtain or fulfill a contract. As of December 31, 2017, the Company has reviewed all of its revenue streams and contracts for its regulated, energy infrastructure and related services, and corporate and other businesses, completing the evaluations of the impact of this new guidance. Based on these evaluations, the Company has determined the new guidance does not materially alter the amount or timing of revenue recognition from the current methodology nor does it have a material transition adjustment upon adoption. Additionally, management does not expect the recognition of any assets from the costs to obtain a contract. Management continues to draft and refine the additional disclosures needed to meet the requirements of the new standard following adoption. The Company will adopt and implement the new guidance on a modified retrospective basis which requires application of standards to all contracts with customers effective January 1, 2018, with the cumulative impact on contracts with performance obligations not yet satisfied as of December 31, 2017, recognized as an adjustment to Retained Earnings on the Consolidated Balance Sheet.

Leases. In February 2016, the FASB issued an accounting standard update which revises the existing guidance for leases. Under the revised guidance, lessees will be required to recognize a "right-of-use" asset and a lease liability for all leases with a term greater than 12 months. The new standard also requires additional quantitative and qualitative disclosures by lessees and lessors to enable users of the financial statements to assess the amount, timing and uncertainty of cash flows arising from leases. The accounting for leases by lessors and the recognition, measurement, and presentation of expenses and cash flows from leases are not expected to significantly change as a result of the new guidance. As of December 31, 2017, ALLETE expects to make $79.9 million in minimum lease payments due in future years (undiscounted). The revised guidance is effective for the Company beginning in the first quarter of 2019 with early adoption permitted. We are currently evaluating the impact of the revised lease guidance on our Consolidated Financial Statements.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
New Accounting Pronouncements (Continued)

Financial Instruments. In January 2016, the FASB issued an accounting standard update which requires entities to measure their investments at fair value and recognize any changes in fair value in net income unless the investments qualify for the practicability exception. The practicability exception will be available for equity investments that do not have readily determinable fair values. The updated guidance is effective for the Company beginning in the first quarter of 2018 and will result in a cumulative-effect adjustment to Retained Earnings on the Consolidated Balance Sheet in the fiscal year of adoption. We have performed a preliminary evaluation of the impact of this update, and based on that evaluation, we do not expect the adoption of the update to have a material impact on our Consolidated Financial Statements.

Classification of Certain Cash Receipts and Cash Payments. In August 2016, the FASB issued an accounting standard update which addresses the following eight specific cash flow issues: debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies (including bank-owned life insurance policies); distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. This accounting guidance is effective for the Company beginning in the first quarter of 2018. We do not expect the adoption of the update to have a material impact on our Consolidated Statement of Cash Flows.

Statement of Cash Flows: Restricted Cash. In November 2016, the FASB issued an accounting standard update related to the presentation of restricted cash in the Company's Consolidated Statement of Cash Flows. The update requires that the Consolidated Statement of Cash Flows explain the change during the period in cash, cash equivalents, and restricted cash. Restricted cash should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the Consolidated Statement of Cash Flows. This accounting guidance is effective for the Company beginning in the first quarter of 2018 and will be applied retrospectively to all periods presented. The guidance will result in changes to the Company's Consolidated Statement of Cash Flows such that restricted cash amounts will be included in the beginning-of-period and end-of-period cash and cash equivalents totals when adopted for our fiscal year beginning January 1, 2018. We do not expect the adoption of the update to have a material impact on our Consolidated Statement of Cash Flows.

Revision of Prior Balance Sheet. During the first quarter of 2017, the Company identified an error related to the deferred income tax treatment associated with its Wholesale and Retail Contra AFUDC Regulatory Liability. The Company evaluated the materiality of the error and concluded that it was not material to any previously issued historical financial statements. The Company has revised its Consolidated Balance Sheet as of December 31, 2016, by decreasing Regulatory Assets and Deferred Income Taxes by $29.5 million . The correction had no impact on our Consolidated Statement of Income.

Reclassification of Prior Income Statement. Beginning with the second quarter of 2017, the Company enhanced its presentation of Operating Revenue and certain Operating Expenses on the Consolidated Statement of Income by presenting the caption Operating Revenue separately as Operating Revenue – Utility and Operating Revenue – Non-utility. In conformity with the current presentation, we now present $1,007.7 million and $991.2 million of Operating Revenue as Operating Revenue – Utility for the years ended December 31, 2016 , and 2015 , respectively, as it is generated from our regulated utility operations. Non-utility revenue of $339.0 million and $495.2 million for the years ended December 31, 2016 , and 2015 respectively, is now presented as Operating Revenue – Non-utility. In addition, the captions Fuel and Purchased Power and Cost of Sales have been updated to Fuel, Purchased Power and Gas – Utility and Cost of Sales – Non-utility. As a result, we have reclassified $7.0 million relating to the cost of gas sales at SWL&P from the historic caption Cost of Sales to Fuel, Purchased Power and Gas – Utility for the year ended December 31, 2016 , and $7.9 million for the year ended December 31, 2015 .

NOTE 2. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment

As of December 31	2017	2016
Millions		
Regulated Operations		
Property, Plant and Equipment in Service	$4,523.7	$4,437.0
Construction Work in Progress	121.6	84.2
Accumulated Depreciation	(1,520.5)	(1,426.1)
Regulated Operations – Net	3,124.8	3,095.1
ALLETE Clean Energy		
Property, Plant and Equipment in Service	482.5	472.3
Construction Work in Progress	144.9	101.0
Accumulated Depreciation	(60.8)	(41.0)
ALLETE Clean Energy – Net	566.6	532.3
U.S. Water Services		
Property, Plant and Equipment in Service	24.8	19.5
Accumulated Depreciation	(10.4)	(6.9)
U.S. Water Services – Net	14.4	12.6
Corporate and Other *(a)*		
Property, Plant and Equipment in Service	204.7	179.8
Construction Work in Progress	5.0	2.8
Accumulated Depreciation	(93.1)	(81.4)
Corporate and Other – Net	116.6	101.2
Property, Plant and Equipment – Net	$3,822.4	$3,741.2

(a) Primarily includes BNI Energy and a small amount of non-rate base generation.

Depreciation is computed using the straight-line method over the estimated useful lives of the various classes of assets.

Estimated Useful Lives of Property, Plant and Equipment

Regulated Operations		ALLETE Clean Energy *(a)*	5 to 35 years
Generation	5 to 50 years	U.S. Water Services	3 to 39 years
Transmission	44 to 67 years	Corporate and Other	3 to 50 years
Distribution	18 to 65 years		

(a) ALLETE Clean Energy's Property, Plant and Equipment consists primarily of WTGs with estimated useful lives ranging from 30 years to 35 years.

Asset Retirement Obligations. We recognize, at fair value, obligations associated with the retirement of certain tangible, long-lived assets that result from the acquisition, construction, development or normal operation of the asset. Asset retirement obligations (AROs) relate primarily to the decommissioning of our coal-fired and wind energy facilities, and land reclamation at BNI Energy. AROs are included in Other Non-Current Liabilities on the Consolidated Balance Sheet. The associated retirement costs are capitalized as part of the related long-lived asset and depreciated over the useful life of the asset. Removal costs associated with certain distribution and transmission assets have not been recognized, as these facilities have indeterminate useful lives.

Conditional asset retirement obligations have been identified for treated wood poles and remaining polychlorinated biphenyl and asbestos-containing assets; however, removal liabilities have not been recognized because they are considered immaterial to our Consolidated Financial Statements.

Long-standing ratemaking practices approved by applicable state and federal regulatory authorities have allowed provisions for future plant removal costs in depreciation rates. These plant removal cost recoveries are classified either as AROs or as a regulatory liability for non-AROs. To the extent annual accruals for plant removal costs differ from accruals under approved depreciation rates, a regulatory asset has been established in accordance with GAAP for AROs. (See Note 4. Regulatory Matters.)

NOTE 2. PROPERTY, PLANT AND EQUIPMENT (Continued)

Asset Retirement Obligations	
Millions	
Obligation as of December 31, 2015	$131.4
Accretion	8.0
Liabilities Settled	(6.5)
Revisions in Estimated Cash Flows	3.7
Obligation as of December 31, 2016	136.6
Accretion	7.6
Liabilities Settled	(5.9)
Revisions in Estimated Cash Flows	(15.6)
Obligation as of December 31, 2017	$122.7

NOTE 3. JOINTLY-OWNED FACILITIES AND PROJECTS

Boswell Unit 4. Minnesota Power owns 80 percent of the 585 MW Boswell Unit 4. While Minnesota Power operates the plant, certain decisions about the operations of Boswell Unit 4 are subject to the oversight of a committee on which it and WPPI Energy, the owner of the remaining 20 percent , have equal representation and voting rights. Each owner must provide its own financing and is obligated to its ownership share of operating costs. Minnesota Power's share of operating expenses for Boswell Unit 4 is included in Operating Expenses on the Consolidated Statement of Income.

CapX2020. Minnesota Power was a participant in the CapX2020 initiative which represented an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX2020, which consisted of electric cooperatives and municipal and investor-owned utilities, including Minnesota's largest transmission owners, assessed the transmission system and projected growth in customer demand for electricity through 2020. Minnesota Power participated in three CapX2020 projects which were completed and placed in service in 2011, 2012 and 2015.

Minnesota Power's investments in jointly-owned facilities and projects and the related ownership percentages are as follows:

Regulated Utility Plant	Plant in Service	Accumulated Depreciation	Construction Work in Progress	% Ownership
Millions				
As of December 31, 2017				
Boswell Unit 4	$668.2	$222.8	$8.2	80
CapX2020 Projects	101.0	8.4	—	9.3 - 14.7
Total	$769.2	$231.2	$8.2	
As of December 31, 2016				
Boswell Unit 4	$668.1	$211.2	$8.1	80
CapX2020 Projects	101.2	5.9	—	9.3 - 14.7
Total	$769.3	$217.1	$8.1	

NOTE 4. REGULATORY MATTERS

Electric Rates. Entities within our Regulated Operations segment file for periodic rate revisions with the MPUC, PSCW or FERC. As authorized by the MPUC, Minnesota Power also recognizes revenue under cost recovery riders for transmission, renewable and environmental investments and expenditures. (See *Transmission Cost Recovery Rider, Renewable Cost Recovery Rider* and *Environmental Improvement Rider* .) Revenue from cost recovery riders was $96.9 million in 2017 ($97.1 million in 2016 ; $89.6 million in 2015).

NOTE 4. REGULATORY MATTERS (Continued)
Electric Rates (Continued)

2016 Minnesota General Rate Case. In November 2016, Minnesota Power filed a retail rate increase request with the MPUC seeking an average increase of approximately 9 percent for retail customers. The rate filing sought a return on equity of 10.25 percent and a 53.81 percent equity ratio. On an annualized basis, the requested final rate increase would have generated approximately $55 million in additional revenue. In December 2016, Minnesota Power filed a request to modify its original interim rate proposal reducing its requested interim rate increase to $34.7 million from the original request of approximately $49 million due to a change in its electric sales forecast. In December 2016 orders, the MPUC accepted the November 2016 filing as complete and authorized an annual interim rate increase of $34.7 million beginning January 1, 2017 .

On February 23, 2017, Minnesota Power filed an additional request to further reduce its requested interim rate increase. In an order dated April 13, 2017, the MPUC approved Minnesota Power's updated retail rate request resulting in a reduction in the annual interim rate increase to $32.2 million beginning May 1, 2017. As a result of working with intervenors and further developments as the rate review progressed, Minnesota Power's final rate request was adjusted to approximately $49 million on an annualized basis. At a hearing on January 18, 2018, the MPUC made determinations regarding Minnesota Power's general rate case including allowing a return on common equity of 9.25 percent and a 53.81 percent equity ratio. Upon commencement of final rates, we expect additional revenue of approximately $13 million on an annualized basis. Final rates are expected to commence in the fourth quarter of 2018; interim rates will be collected through this period which will be fully offset by the recognition of a corresponding reserve. As a result of the MPUC's decisions on January 18, 2018, Minnesota Power has recorded a reserve for an interim rate refund of approximately $32 million as of December 31, 2017 . The MPUC also disallowed recovery of Minnesota Power's regulatory asset for deferred fuel adjustment clause costs due to the anticipated adoption of a forward-looking fuel adjustment clause methodology resulting in a $19.5 million pre-tax charge to Fuel, Purchased Power and Gas – Utility in 2017. An order from the MPUC setting forth the effective date of final rates is expected by March 12, 2018. Minnesota Power will review this order for potential reconsideration of certain issues at that time.

As part of its decision in Minnesota Power's 2016 general rate case, the MPUC extended the depreciable lives of Boswell Unit 3, Unit 4 and common facilities to 2050 primarily to mitigate rate increases for our customers, and shortened the depreciable lives of Boswell Unit 1 and Unit 2 to 2022, resulting in a net decrease to depreciation expense of approximately $25 million pre-tax in 2017.

Energy-Intensive Trade-Exposed Customer Rates. An EITE customer ratemaking law was enacted in 2015 which established that it is the energy policy of Minnesota to have competitive rates for certain industries such as mining and forest products. In 2015, Minnesota Power filed a rate schedule petition with the MPUC for EITE customers and a corresponding rider for EITE cost recovery. In a March 2016 order, the MPUC dismissed the petition without prejudice. In June 2016, Minnesota Power filed a revised EITE petition with the MPUC which included additional information on the net benefits analysis, limits on eligible customers and term lengths for the EITE discount. The rate adjustments were intended to be revenue and cash flow neutral to Minnesota Power. The MPUC approved a reduction in rates for EITE customers in a December 2016 order and subsequently approved cost recovery in an order dated April 20, 2017; collection of the discount was subject to the MPUC's review of Minnesota Power's compliance filing implementing approval of a recovery mechanism, with the subsequent order issued on October 13, 2017, that modified the order dated April 20, 2017. During 2017, Minnesota Power provided discounts of $8.6 million which were recorded as a receivable. On September 29, 2017, Minnesota Power informed its EITE customers that it has suspended the EITE discount due to a concern that it was not revenue and cash flow neutral to Minnesota Power based on an MPUC decision at a hearing on September 7, 2017, as well as the interim rate reduction and decisions in its 2016 general rate case. Based on the MPUC's decisions at a hearing on January 18, 2018, as part of Minnesota Power's 2016 general rate case, Minnesota Power reinstated the EITE discount effective January 1, 2018. Minnesota Power expects the discount to EITE customers to be approximately $15 million annually based on EITE customer current operating levels. While interim rates are in effect for Minnesota Power's 2016 general rate case, EITE discounts will offset interim rate refund reserves for non-EITE customers.

FERC-Approved Wholesale Rates. Minnesota Power has 16 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a wholesale customer of Minnesota Power. All wholesale contracts include a termination clause requiring a three -year notice to terminate.

NOTE 4. REGULATORY MATTERS (Continued)
Electric Rates (Continued)

Minnesota Power's wholesale electric contract with the Nashwauk Public Utilities Commission is effective through at least December 31, 2032. No termination notice may be given for this contract prior to July 1, 2029. The wholesale electric service contracts with SWL&P and another municipal customer are effective through at least February 28, 2021, and through June 30, 2019, respectively. Under the agreement with SWL&P, no termination notice has been given. The other municipal customer provided a contract termination notice in June 2016. Minnesota Power currently provides approximately 29 MW of average monthly demand to this customer. The rates included in these three contracts are set each July 1 based on a cost-based formula methodology, using estimated costs and a rate of return that is equal to Minnesota Power's authorized rate of return for Minnesota retail customers. The formula-based rate methodology also provides for a yearly true-up calculation for actual costs incurred.

Minnesota Power's wholesale electric contracts with 14 municipal customers are effective through at least December 31, 2024. No termination notices may be given prior to three years before maturity. These contracts include fixed capacity charges through 2018; beginning in 2019, the capacity charge will be determined using a cost-based formula methodology with limits on the annual change from the previous year's capacity charge. The base energy charge for each year of the contract term will be set each January 1, subject to monthly adjustment, and will also be determined using a cost-based formula methodology.

Transmission Cost Recovery Rider. Minnesota Power has an approved cost recovery rider in place for certain transmission investments and expenditures. In a February 2016 order, the MPUC approved Minnesota Power's updated customer billing rates which allows Minnesota Power to charge retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. As a result of the MPUC approval of the certificate of need for the GNTL in 2015, the project is eligible for cost recovery under the existing transmission cost recovery rider. Minnesota Power is funding the construction of the GNTL with a subsidiary of Manitoba Hydro (see *Great Northern Transmission Line*), and anticipates including its portion of the investments and expenditures for the GNTL in future transmission bill factor filings.

Renewable Cost Recovery Rider. Minnesota Power has an approved cost recovery rider in place for investments and expenditures related to Bison, and the restoration and repair of Thomson. The cost recovery rider allows Minnesota Power to charge retail customers on a current basis for the costs of constructing certain renewable investments plus a return on the capital invested. Updated customer billing rates for the renewable cost recovery rider were approved by the MPUC in an order dated November 8, 2017.

In a November 2016 order, the MPUC directed Minnesota Power to attribute all North Dakota investment tax credits realized from Bison to Minnesota Power regulated retail customers. As a result of the adverse regulatory outcome, Minnesota Power recorded a regulatory liability and a reduction in Operating Revenue of approximately $15 million in 2016. The North Dakota investment tax credits previously recognized as income tax credits in Corporate and Other were reversed in 2016 resulting in an $8.8 million charge to net income in 2016. In December 2016, Minnesota Power submitted a request for reconsideration with the MPUC. In an order dated February 14, 2017, the MPUC decided to reconsider its November 2016 order.

In an order dated December 7, 2017, the MPUC modified its November 2016 order to allow Minnesota Power to account for North Dakota investment tax credits based on the long-standing regulatory precedents of stand-alone allocation methodology of accounting for income taxes. As a result of the favorable regulatory outcome, Minnesota Power recorded a reduction in its regulatory liability and an increase in Operating Revenue of approximately $14 million in 2017. The North Dakota investment tax credits were reestablished as income tax credits in Corporate and Other, resulting in a $7.9 million increase to net income in 2017.

The stand-alone method provides that income taxes (and credits) are calculated as if Minnesota Power was the only entity included in ALLETE's consolidated federal and unitary state income tax returns. Minnesota Power has recorded a regulatory liability for North Dakota investment tax credits generated by its jurisdictional activity and expected to be realized in the future. North Dakota investment tax credits attributable to ALLETE's apportionment and income of ALLETE's other subsidiaries are included in Corporate and Other operations.

Minnesota Power also has approval for current cost recovery of investments and expenditures related to compliance with the Minnesota Solar Energy Standard. (See *Minnesota Solar Energy Standard.*) Currently, there is no approved customer billing rate for solar costs.

NOTE 4. REGULATORY MATTERS (Continued)
Electric Rates (Continued)

Environmental Improvement Rider . Minnesota Power has an approved environmental improvement rider in place for investments and expenditures related to the implementation of the Boswell Unit 4 mercury emissions reduction plan completed in 2015. Updated customer billing rates for the environmental improvement rider were approved by the MPUC in a December 2016 order; however, in an order dated March 22, 2017, the MPUC approved a request by Minnesota Power to delay implementation of the updated rates until resolution of its 2016 general rate case. (See *2016 Minnesota General Rate Case.)*

Fuel Adjustment Clause Reform Pilot . In an order dated December 19, 2017, the MPUC adopted a three-year pilot program to implement certain procedural reforms to the Minnesota utilities' automatic fuel adjustment clause (FAC) for fuel and purchased power. The order changes the method of accounting for all Minnesota electric utilities to a monthly budgeted, forwarded-looking FAC with an annual prudence review and true-up to actual allowed costs. The MPUC is seeking input from Minnesota electric utilities and other stakeholders on the implementation and transition accounting needed to adopt the change. The three-year pilot program is expected to begin in 2019. At a hearing on January 18, 2018, the MPUC disallowed recovery of Minnesota Power's regulatory asset for deferred fuel adjustment clause costs due to the anticipated adoption of the forward-looking fuel adjustment clause methodology in this proceeding resulting in a $19.5 million pre-tax charge to Fuel, Purchased Power and Gas – Utility in 2017.

Tax Cuts and Jobs Act of 2017 . On December 29, 2017, the MPUC opened a docket to review the effects of the TCJA on electric and natural gas rates and services in Minnesota, including the legislation's impact on tax rates and utilities' deferred income tax assets and liabilities. On January 19, 2018, the MPUC issued a notice of request for information and established comment periods with an initial filing required by March 2, 2018. On January 10, 2018, the PSCW also opened a docket to review the effects of this legislation and directed Wisconsin utilities to defer its impacts until further direction is provided by the PSCW. We have recorded the impact of the remeasurement of deferred income tax assets and liabilities resulting from the federal income tax rate change of the TCJA for Minnesota Power and SWL&P as regulatory assets and liabilities as the benefits of the TCJA are expected to be passed back to our customers over time. (See *Regulatory Assets and Liabilities* .) The final amount and timing over which the benefits of the TCJA will be passed back to customers is expected to be determined in these dockets; however, we are unable to predict the outcome of these regulatory proceedings.

2016 Wisconsin General Rate Case. SWL&P's current retail rates are based on a 2017 PSCW retail rate order effective August 14, 2017, that allows for a 10.5 percent return on common equity and a 55 percent equity ratio. SWL&P's retail rates prior to August 14, 2017, were based on a 2012 PSCW retail rate order that provided for a 10.9 percent return on equity. The 2017 PSCW retail rate order authorizes SWL&P to collect on average a 2.9 percent increase in rates for retail customers (3.8 percent increase in electric rates; 4.8 percent decrease in natural gas rates; and 9.8 percent increase in water rates). On an annualized basis, SWL&P expects to collect additional revenue of $2.5 million .

Integrated Resource Plan. In 2015, Minnesota Power filed its 2015 IRP with the MPUC which included an analysis of a variety of existing and future energy resource alternatives and a projection of customer cost impact by class. The 2015 IRP also contained steps in Minnesota Power's *EnergyForward* strategic plan including the economic idling of Taconite Harbor Units 1 and 2 which occurred in September 2016, the ceasing of coal-fired operations at Taconite Harbor in 2020, and the addition of between 200 MW and 300 MW of natural gas-fired generation in the next decade. In a July 2016 order, the MPUC approved Minnesota Power's 2015 IRP with modifications. The order accepted Minnesota Power's plans for Taconite Harbor, directed Minnesota Power to retire Boswell Units 1 and 2 no later than 2022, required an analysis of generation and demand response alternatives to be filed with a natural gas resource proposal, and required Minnesota Power to conduct request for proposals for additional wind, solar and demand response resource additions subject to further MPUC approvals. In October 2016, Minnesota Power announced Boswell Units 1 and 2 will be retired in 2018.

On July 28, 2017, Minnesota Power submitted a resource package to the MPUC requesting approval of PPAs for the output of a 250 MW wind energy facility and a 10 MW solar energy facility as well as approval of a 250 MW natural gas energy PPA. These agreements will be subject to MPUC approval of the construction of a 525 MW to 550 MW combined-cycle natural gas-fired generating facility which will be jointly owned by Dairyland Power Cooperative and a subsidiary of ALLETE. Minnesota Power would purchase approximately 50 percent of the facility's output starting in 2025. In an order dated September 19, 2017, the MPUC approved Minnesota Power's request to extend the next IRP filing deadline until October 1, 2019, and Minnesota Power's request that approval for the natural gas energy PPA be decided through an administrative law judge process. The administrative law judge is expected to provide a recommendation by July 2018, and the Company anticipates a MPUC decision in the second half of 2018. The MPUC did not take any action regarding the wind and solar energy PPAs which will be refiled separately from the natural gas energy PPA.

NOTE 4. REGULATORY MATTERS (Continued)

Great Northern Transmission Line . Minnesota Power and Manitoba Hydro have proposed construction of the GNTL, an approximately 220 -mile 500 -kV transmission line between Manitoba and Minnesota's Iron Range. In 2015, a certificate of need was approved by the MPUC. Based on this approval, Minnesota Power's portion of the investments and expenditures for the project are eligible for cost recovery under its existing transmission cost recovery rider and are anticipated to be included in future transmission cost recovery filings. *(* See *Transmission Cost Recovery Rider.)* Also in 2015, the FERC approved our request to recover on construction work in progress related to the GNTL from Minnesota Power's wholesale customers. In an April 2016 order, the MPUC approved the route permit for the GNTL which largely follows Minnesota Power's preferred route, including the international border crossing, and in November 2016, the U.S. Department of Energy issued a presidential permit to cross the U.S.-Canadian border, which was the final major regulatory approval needed before construction in the U.S. could begin. Site clearing and pre-construction activities commenced in the first quarter of 2017 with construction expected to be completed in 2020. Total project cost in the U.S., including substation work, is estimated to be between $560 million and $710 million , of which Minnesota Power's portion is expected to be between $300 million and $350 million ; the difference will be recovered from a subsidiary of Manitoba Hydro as contributions in aid of construction. Total project costs of $152.4 million have been incurred through December 31, 2017 , of which $67.6 million has been recovered from a subsidiary of Manitoba Hydro.

Manitoba Hydro must obtain regulatory and governmental approvals related to a new transmission line in Canada. In 2015, Manitoba Hydro submitted the final preferred route and EIS for the transmission line in Canada to the Manitoba Conservation and Water Stewardship for regulatory approval. In December 2016, Manitoba Hydro filed an application with the National Energy Board in Canada requesting authorization to construct and operate an international transmission line. Both provincial and federal approvals are pending. Construction of Manitoba Hydro's hydroelectric generation facility commenced in 2014 and is anticipated to be in service by early 2021.

Conservation Improvement Program. Minnesota requires electric utilities to spend a minimum of 1.5 percent of gross operating revenues from service provided in the state on energy CIPs each year and establish an annual energy-savings goal of 1.5 percent of annual retail energy sales. These investments are recovered from certain retail customers through a combination of the conservation cost recovery charge included in retail base rates and a conservation program adjustment, which is adjusted annually through the CIP consolidated filing. The MPUC allows utilities to accumulate, in a deferred account for future cost recovery, all CIP expenditures, any financial incentive earned for cost-effective program achievements and a carrying charge on the deferred account balance. Minnesota Power refers to its conservation programs collectively as the "Power of One". On November 16, 2017, the Minnesota Department of Commerce approved Minnesota Power's modified CIP triennial filing for 2017 through 2019, which outlines Minnesota Power's CIP spending and energy-saving goals for 2017 through 2019. Minnesota Power's CIP investment goal was $10.3 million for 2017 ($7.3 million for 2016 ; $7.1 million for 2015), with actual spending of $8.1 million in 2017 ($7.4 million in 2016 ; $6.6 million in 2015). The investment goals for 2018 and 2019 are $10.3 million and $10.5 million , respectively.

On April 3, 2017, Minnesota Power submitted its 2016 CIP consolidated filing, which detailed Minnesota Power's CIP program results and requested a CIP financial incentive of $5.5 million based upon MPUC procedures. In an order dated June 22, 2017, the MPUC approved Minnesota Power's CIP consolidated filing, including the requested CIP financial incentive which was recorded as revenue and as a regulatory asset in 2017. The approved financial incentive will be recovered through customer billing rates in 2017 and 2018. In 2016 and 2015, the CIP financial incentives recognized were $7.5 million and $6.2 million , respectively. CIP financial incentives are recognized in the period in which the MPUC approves the filing.

MISO Return on Equity Complaints. In 2013, several customer groups located within the MISO service area filed complaints with the FERC requesting, among other things, a reduction in the base return on equity used by MISO transmission owners, including ALLETE and ATC, to 9.15 percent . In 2015, a federal administrative law judge ruled on the complaint proposing a reduction in the base return on equity to 10.32 percent , or 10.82 percent including an incentive adder for participation in a regional transmission organization. In September 2016, the FERC issued an order affirming the administrative law judge's recommendation.

In 2015, an additional complaint was filed with the FERC seeking an order to further reduce the base return on equity to 8.67 percent. In June 2016, a federal administrative law judge ruled on the additional complaint proposing a further reduction in the base return on equity to 9.70 percent , or 10.20 percent including an incentive adder for participation in a regional transmission organization, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge's recommendation is pending, which is not expected to have a material impact on our Consolidated Financial Statements.

NOTE 4. REGULATORY MATTERS (Continued)

Minnesota Solar Energy Standard. Minnesota law requires at least 1.5 percent of total retail electric sales, excluding sales to certain customers, to be generated by solar energy by the end of 2020. At least 10 percent of the 1.5 percent mandate must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 40 kW or less and community solar garden subscriptions. In a 2016 order, the MPUC approved Camp Ripley, a 10 MW utility scale solar project at the Camp Ripley Minnesota Army National Guard base and training facility near Little Falls, Minnesota, as eligible to meet the solar energy standard and for current cost recovery. Camp Ripley was completed in the fourth quarter of 2016. In a July 2016 order, the MPUC approved a community solar garden project in northeastern Minnesota, which is comprised of a 1 MW solar array owned and operated by a third party with the output purchased by Minnesota Power and a 40 kW solar array that is owned and operated by Minnesota Power. Minnesota Power believes Camp Ripley and the community solar garden arrays will meet approximately one-third of the overall mandate. Additionally, in an order dated February 10, 2017, the MPUC approved Minnesota Power's proposal to increase the amount of solar rebates available for customer-sited solar installations and recover costs of the program through Minnesota Power's renewable cost recovery rider. The proposal to incentivize customer-sited solar installations and the community solar garden subscriptions is expected to meet a portion of the required small scale solar mandate.

Regulatory Assets and Liabilities. Our regulated utility operations are subject to accounting guidance for the effect of certain types of regulation. Regulatory assets represent incurred costs that have been deferred as they are probable for recovery in customer rates. Regulatory liabilities represent obligations to make refunds to customers and amounts collected in rates for which the related costs have not yet been incurred. The Company assesses quarterly whether regulatory assets and liabilities meet the criteria for probability of future recovery or deferral. No regulatory assets or liabilities are currently earning a return. The recovery, refund or credit to rates for these regulatory assets and liabilities will occur over the periods either specified by the applicable regulatory authority or over the corresponding period related to the asset or liability.

Regulatory Assets and Liabilities

As of December 31	2017	2016
Millions		
Current Regulatory Assets *(a)*		
Deferred Fuel Adjustment Clause	—	$18.6
Non-Current Regulatory Assets		
Defined Benefit Pension and Other Postretirement Benefit Plans *(b)*	$220.3	226.1
Income Taxes *(c)(d)*	112.8	33.8
Asset Retirement Obligations *(e)*	29.6	26.0
Manufactured Gas Plant *(f)*	8.1	1.0
PPACA Income Tax Deferral	5.0	5.0
Conservation Improvement Program *(g)*	3.3	4.0
Cost Recovery Riders *(h)*	—	30.5
Other	5.6	3.7
Total Non-Current Regulatory Assets	384.7	330.1
Total Regulatory Assets	$384.7	$348.7
Non-Current Regulatory Liabilities		
Income Taxes *(d)*	$411.2	$19.1
Wholesale and Retail Contra AFUDC *(i)*	57.9	56.8
Provision for Interim Rate Refund *(j)*	23.7	—
Plant Removal Obligations	20.3	19.1
North Dakota Investment Tax Credits *(k)*	14.1	28.2
Cost Recovery Riders *(h)*	2.2	—
Other	2.6	2.6
Total Non-Current Regulatory Liabilities	$532.0	$125.8

(a) Current regulatory assets are presented within Prepayments and Other on the Consolidated Balance Sheet. At a hearing on January 18, 2018, the MPUC disallowed recovery of Minnesota Power's regulatory asset for deferred fuel adjustment clause costs resulting in a $19.5 million pre-tax charge to Fuel, Purchased Power and Gas – Utility in 2017. (See 2016 Minnesota General Rate Case.)

(b) Defined benefit pension and other postretirement items included in our Regulated Operations, which are otherwise required to be recognized in accumulated other comprehensive income as actuarial gains and losses as well as prior service costs and credits, are recognized as regulatory assets or regulatory liabilities on the Consolidated Balance Sheet. The asset or liability will decrease as the deferred items are amortized and recognized as components of net periodic benefit cost. (See Note 15. Pension and Other Postretirement Benefit Plans.)

(c) See Note 1. Operations and Significant Accounting Policies – Revision of Prior Balance Sheet.

(d) These costs represent the difference between deferred income taxes recognized for financial reporting purposes and amounts previously billed to our customers. The increase in 2017 is primarily due to the remeasurement of deferred income tax assets and liabilities for our Regulated Operations resulting from the TCJA. The benefits of the TCJA for Minnesota Power and SWL&P are expected to be passed back to customers over time primarily based upon the normalization provisions of the U.S. Internal Revenue Code over the life of the related property, plant and equipment with the remainder passed back based upon the determinations of regulatory authorities. (See Note 1. Operations and Significant Accounting Policies, and Tax Cuts and Jobs Act of 2017.) The balances not related to remeasurement will decrease over the remaining life of the related temporary differences and flow through current income taxes.

(e) Asset retirement obligations will accrete and be amortized over the lives of the related property with asset retirement obligations.

(f) The manufactured gas plant regulatory asset represents costs of remediation for a former manufactured gas plant site located in Superior, Wisconsin, and formerly operated by SWL&P. We expect recovery of these remediation costs to be allowed by the PSCW in rates over time.

(g) The conservation improvement program regulatory asset represents CIP expenditures, any financial incentive earned for cost-effective program achievements and a carrying charge deferred for future cost recovery over the next year following MPUC approval.

(h) The cost recovery rider regulatory assets and liabilities are revenues not yet collected from our customers and cash collections from our customers in excess of the revenue recognized, respectively, primarily due to capital expenditures related to Bison, investment in CapX2020 projects, the Boswell Unit 4 environmental upgrade and the GNTL, and are recognized in accordance with the accounting standards for alternative revenue programs. The cost recovery rider regulatory assets and liabilities as of December 31, 2017 , will be recovered or returned within the next two years.

(i) Wholesale and Retail Contra AFUDC represents amortization to offset AFUDC Equity and Debt recorded during the construction period of our cost recovery rider projects prior to placing the projects in service. The regulatory liability will decrease over the remaining depreciable life of the related asset.

(j) This amount is expected to be refunded to Minnesota Power's regulated retail customers in the first quarter of 2019 and includes $8.6 million of EITE discounts that will be offset against interim rate refunds. (See 2016 Minnesota General Rate Case and Energy-Intensive Trade-Exposed Customer Rates.)

(k) North Dakota investment tax credits expected to be realized from Bison that will be credited to Minnesota Power's regulated retail customers through future renewable cost recovery rider fillings as the tax credits are utilized.

NOTE 5. INVESTMENT IN ATC

Our wholly-owned subsidiary, ALLETE Transmission Holdings, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in portions of Wisconsin, Michigan, Minnesota and Illinois. We account for our investment in ATC under the equity method of accounting. As of December 31, 2017 , our equity investment in ATC was $118.7 million ($135.6 million as of December 31, 2016). On January 31, 2018, we invested an additional $1.6 million in ATC. In total, we expect to invest approximately $6 million throughout 2018 .

ALLETE's Investment in ATC

Year Ended December 31	**2017**	**2016**
Millions		
Equity Investment Beginning Balance	$135.6	$124.5
Cash Investments	7.8	5.4
Equity in ATC Earnings	22.5	18.5
Distributed ATC Earnings	(19.3)	(12.8)
Remeasurement of Deferred Income Taxes *(a)*	(27.9)	—
Equity Investment Ending Balance	$118.7	$135.6

(a) Impact of the remeasurement of deferred income tax assets and liabilities resulting from the TCJA. (See Note 1. Operations and Significant Accounting Policies.)

ATC Summarized Financial Data

Balance Sheet Data

As of December 31	**2017**	**2016**
Millions		
Current Assets	$87.7	$75.8
Non-Current Assets	4,598.9	4,312.9
Total Assets	$4,686.6	$4,388.7
Current Liabilities	$767.2	$495.1
Long-Term Debt	1,790.6	1,865.3
Other Non-Current Liabilities	240.3	271.5
Members' Equity	1,888.5	1,756.8
Total Liabilities and Members' Equity	$4,686.6	$4,388.7

Income Statement Data

Year Ended December 31	**2017**	**2016**	**2015**
Millions			
Revenue	$721.6	$650.8	$615.8
Operating Expense	344.9	322.5	319.3
Other Expense	104.1	95.5	96.1
Net Income	$272.6	$232.8	$200.4
ALLETE's Equity in Net Income	$22.5	$18.5	$16.3

In September 2016, the FERC issued an order reducing ATC's authorized return on equity to 10.32 percent , or 10.82 percent including an incentive adder for participation in a regional transmission organization. Prior to this order, ATC had been allowed a return on equity of 12.2 percent which had been impacted by reductions for estimated refunds related to complaints filed with the FERC by several customers located within the MISO service area.

In June 2016, a federal administrative law judge ruled on an additional complaint proposing a further reduction in the base return on equity to 9.70 percent , or 10.20 percent including an incentive adder for participation in a regional transmission organization, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge's recommendation is pending. (See Note 4. Regulatory Matters.)

NOTE 6. ACQUISITIONS

The following acquisitions are consistent with ALLETE's stated strategy of investing in energy infrastructure and related services businesses to complement its regulated businesses, balance exposure to business cycles and changing demand, and provide potential long-term earnings growth. The pro forma impact of the following acquisitions was not significant , either individually or in the aggregate, to the results of the Company for the years ended December 31, 2017 , 2016 and 2015 .

2017 Activity.

Tonka Water. On Septemb er 1, 2017, U.S. Water Services acquired 100 percent of Tonka Water . Total consideration for the transaction was $19.2 million , including a working capital adjustment. Consideration of $19.0 million was p aid in cash on the acquisition date and a working capital adjustment of $0.2 million was pa id in the fourth quarter of 2017. Tonka Water is a supplier of municipal and industrial water treatment systems and will expand U.S. Water Services' geographic and customer markets.

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. The allocation of the purchase price is subject to judgment and the preliminary estimated fair value of the assets acquired and the liabilities assumed may be adjusted when the valuation analysis is complete in subsequent periods. Preliminary estimates subject to adjustment in subsequent periods relate primarily to income tax liabilities; subsequent adjustments could impact the amount of goodwill recorded. Fair value measurements were valued primarily using the discounted cash flow method and replacement cost basis.

Millions	
Assets Acquired	
Accounts Receivable	$5.1
Other Current Assets	5.1
Trade Names *(a)*	0.9
Goodwill *(a)(b)*	16.9
Other Non-Current Assets	0.2
Total Assets Acquired	$28.2
Liabilities Assumed	
Current Liabilities	$9.0
Total Liabilities Assumed	$9.0
Net Identifiable Assets Acquired	$19.2

(a) Presented within Goodwill and Intangible Assets – Net on the Consolidated Balance Sheet. (See Note 7. Goodwill and Intangible Assets.)

(b) Recognized goodwill is attributable to the assembled workforce and anticipated synergies. For tax purposes, the purchase price allocation resulted in $4.1 million of deductible goodwill.

Acquisition-related costs were immaterial, expensed as incurred during 2017 and recorded in Operating and Maintenance on the Consolidated Statement of Income.

2016 Activity.

Acquisition of Non-Controlling Interest. In April 2016, ALLETE Clean Energy acquired the non-controlling interest in the limited liability company that owns its Condon wind energy facility for $8.0 million . This transaction was accounted for as an equity transaction, and no gain or loss was recognized in net income or other comprehensive income. As a result of the acquisition, the Condon wind energy facility is now a wholly-owned subsidiary of ALLETE Clean Energy.

WEST. In October 2016 , U.S. Water Services acquired 100 percent of Water & Energy Systems Technology of Nevada, Inc. (WEST). Total consideration for the transaction was $6.7 million . Consideration of $5.9 million was paid in cash on the acquisition date, working capital adjustments of $0.2 million were paid in the first six months of 2017 and a $0.6 million payment is due in April 2018. WEST is an integrated water management company and was acquired to expand U.S. Water Services' regional footprint in the Southwestern United States.

NOTE 6. ACQUISITIONS (Continued)
2016 Activity (Continued)

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. The purchase price accounting, which was finalized in the second quarter of 2017, is shown in the following table. Fair value measurements were valued primarily using the discounted cash flow method and replacement cost basis.

Millions	
Assets Acquired	
Cash and Cash Equivalents	$0.1
Other Current Assets	1.0
Customer Relationships *(a)*	2.8
Goodwill *(a)(b)*	4.2
Other Non-Current Assets	0.1
Total Assets Acquired	$8.2
Liabilities Assumed	
Current Liabilities	$0.3
Non-Current Liabilities	1.2
Total Liabilities Assumed	$1.5
Net Identifiable Assets Acquired	$6.7

(a) Presented within Goodwill and Intangible Assets – Net on the Consolidated Balance Sheet. (See Note 7. Goodwill and Intangible Assets.)
(b) For tax purposes, the purchase price allocation resulted in no allocation to goodwill.

Acquisition-related costs were immaterial , expensed as incurred during 2016 and recorded in Operating and Maintenance on the Consolidated Statement of Income.

2015 Activity.

U.S. Water Services. In 2015 , ALLETE acquired U.S. Water Services . Total consideration for the transaction was $202.3 million , which included payment of $166.6 million in cash and an estimated fair value of earnings-based contingent consideration of $35.7 million , as estimated at the date of acquisition, to be paid through 2019. The contingent consideration is presented within Other Non-Current Liabilities on the Consolidated Balance Sheet. The Consolidated Statement of Income reflects 100 percent of the results of operations for U.S. Water Services since the acquisition date as the Company has acquired 100 percent of U.S. Water Services.

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. The purchase price accounting, which was finalized in 2015, is reflected in the following table. Fair value measurements were valued primarily using the discounted cash flow method.

NOTE 6. ACQUISITIONS (Continued)
2015 Activity (Continued)

Millions	
Assets Acquired	
Cash and Cash Equivalents	$0.9
Accounts Receivable	16.8
Inventories *(a)*	13.4
Other Current Assets *(b)*	5.3
Property, Plant and Equipment	10.6
Intangible Assets *(c)*	83.0
Goodwill *(d)*	122.9
Other Non-Current Assets	0.2
Total Assets Acquired	$253.1
Liabilities Assumed	
Current Liabilities	$19.2
Non-Current Liabilities	31.6
Total Liabilities Assumed	$50.8
Net Identifiable Assets Acquired	$202.3

(a) Included in Inventories was $2.7 million of fair value adjustments relating to work in progress and finished goods inventories which were recognized as Cost of Sales within one year from the acquisition date.

(b) Included in Other Current Assets was $1.6 million relating to the fair value of sales backlog. Sales backlog was recognized as Cost of Sales within one year from the acquisition date. Also included in Other Current Assets was restricted cash of $2.1 million relating to cash pledged as collateral for standby letters of credit.

(c) Intangible Assets include customer relationships, patents, non-compete agreements, and trademarks and trade names. (See Note 7. Goodwill and Intangible Assets.)

(d) For tax purposes, the purchase price allocation resulted in $2.9 million of deductible goodwill.

Acquisition-related costs of $3.0 million after-tax were expensed as incurred during 2015 and recorded in Operating and Maintenance on the Consolidated Statement of Income.

Chanarambie/Viking. In 2015 , ALLETE Clean Energy acquired 100 percent of wind energy facilities in southern Minnesota (Chanarambie/Viking) from EDF Renewable Energy, Inc. for $48.0 million .

The facilities have a combined 97.5 MW of generating capability. The wind energy facilities began commercial operations in 2003 and have PSAs in place for their entire output, which expire in 2018 (12 MW) and 2023 (85.5 MW).

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. The purchase price accounting, which was finalized in 2015, is reflected in the following table. Fair value measurements were valued primarily using the discounted cash flow method.

NOTE 6. ACQUISITIONS (Continued)
2015 Activity (Continued)

Millions	
Assets Acquired	
Current Assets	$4.8
Property, Plant and Equipment	103.0
Other Non-Current Assets *(a)*	1.0
Total Assets Acquired	$108.8
Liabilities Assumed	
Current Liabilities *(b)*	$6.7
PSAs	49.0
Non-Current Liabilities	5.1
Total Liabilities Assumed	$60.8
Net Identifiable Assets Acquired	$48.0

(a) Included in Other Non-Current Assets was $0.3 million of goodwill. For tax purposes, the purchase price allocation resulted in no allocation to goodwill.
(b) Current Liabilities included $5.9 million related to the current portion of PSAs.

Acquisition-related costs of $0.2 million after-tax were expensed as incurred during 2015 and recorded in Operating and Maintenance on the Consolidated Statement of Income.

Armenia Mountain. In 2015 , ALLETE Clean Energy acquired 100 percent of a wind energy facility located near Troy, Pennsylvania (Armenia Mountain) from The AES Corporation and a minority shareholder for $111.1 million , plus the assumption of existing debt.

The facility has 100.5 MW of generating capability, began commercial operations in 2009, and has PSAs in place for its entire output, which expire in 2024.

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. The purchase price accounting, which was finalized in 2015, is reflected in the following table. Fair value measurements were valued primarily using the discounted cash flow method.

Millions	
Assets Acquired	
Current Assets *(a)*	$9.0
Property, Plant and Equipment	156.2
Other Non-Current Assets *(b)*	14.4
Total Assets Acquired	$179.6
Liabilities Assumed	
Current Liabilities	$2.9
Long-Term Debt Due Within One Year	5.9
Long-Term Debt	55.0
Other Non-Current Liabilities	4.7
Total Liabilities Assumed	$68.5
Net Identifiable Assets Acquired	$111.1

(a) Included in Current Assets was $1.0 million related to the current portion of PSAs and $6.0 million of restricted cash related to collateral deposits required under its loan agreement.
(b) Included in Other Non-Current Assets was $8.2 million related to the non-current portion of PSAs, $6.1 million of restricted cash related to collateral deposits required under its loan agreements and an immaterial amount of goodwill. For tax purposes, the purchase price allocation resulted in no allocation to goodwill.

NOTE 6. ACQUISITIONS (Continued)
2015 Activity (Continued)

Acquisition-related costs of $1.6 million after-tax were expensed as incurred during 2015 and recorded in Operating and Maintenance on the Consolidated Statement of Income.

A and W Technologies. In 2015 , U.S. Water Services acquired 100 percent of A and W Technologies, Inc. (AWT). Total consideration for the transaction was $9.3 million , which included payment of $8.3 million in cash and a $1.0 million payment made in April 2017. AWT, similar to U.S. Water Services, is an integrated water management company and was acquired to expand U.S. Water Services' regional footprint in the Southeastern United States.

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. The purchase price accounting, which was finalized in 2015, is reflected in the following table. Fair value measurements were valued primarily using the discounted cash flow method.

Millions	
Assets Acquired	
Current Assets	$1.0
Property, Plant and Equipment	0.1
Intangible Assets *(a)*	3.9
Goodwill *(b)*	4.4
Total Assets Acquired	$9.4
Liabilities Assumed	
Current Liabilities	$0.1
Total Liabilities Assumed	$0.1
Net Identifiable Assets Acquired	$9.3

(a) Intangible Assets include customer relationships and non-compete agreements. (See Note 7. Goodwill and Intangible Assets.)
(b) For tax purposes, the purchase price allocation resulted in $4.4 million of deductible goodwill.

Acquisition-related costs were immaterial , expensed as incurred during 2015 and recorded in Operating and Maintenance on the Consolidated Statement of Income.

NOTE 7. GOODWILL AND INTANGIBLE ASSETS

The following table summarizes changes to goodwill by reportable segment:

	ALLETE Clean Energy	U.S. Water Services	Total
Millions			
Balance as of December 31, 2015	$3.3	$127.3	$130.6
Acquired Goodwill *(a)*	—	3.9	3.9
Impairment Charge *(b)*	(3.3)	—	(3.3)
Balance as of December 31, 2016	—	131.2	131.2
Acquired Goodwill *(a)*	—	16.9	16.9
Other Adjustments *(c)*	—	0.2	0.2
Balance as of December 31, 2017	—	$148.3	$148.3

(a) See Note 6. Acquisitions.

(b) The facts and circumstances that led to an impairment of ALLETE Clean Energy's goodwill primarily relate to lower estimated energy prices in periods not under PSAs. Impairment Charge is included in Operating Expenses – Other on the Consolidated Statement of Income. (See Note 1. Operations and Significant Accounting Policies.) ALLETE Clean Energy's goodwill was primarily related to the acquisition of Storm Lake II in 2014.

(c) Finalization of purchase price accounting for U.S. Water Services' acquisition of WEST was completed in 2017 resulting in an adjustment to the goodwill recorded at the time of the initial acquisition.

The following table summarizes changes to intangible assets, net, for the year ended December 31, 2017 :

	December 31, 2016	Additions *(a)*	Amortization	December 31, 2017
Millions				
Intangible Assets				
Definite-Lived Intangible Assets				
Customer Relationships	$59.3	—	$(4.6)	$54.7
Developed Technology and Other *(b)*	6.3	$0.9	(0.9)	6.3
Total Definite-Lived Intangible Assets	65.6	0.9	(5.5)	61.0
Indefinite-Lived Intangible Assets				
Trademarks and Trade Names	16.6	—	n/a	16.6
Total Intangible Assets	$82.2	$0.9	$(5.5)	$77.6

(a) Additions resulting from the September 1, 2017, acquisition of Tonka Water. (See Note 6. Acquisitions.)

(b) Developed Technology and Other includes patents, non-compete agreements, land easements and trade names with finite lives.

Customer relationships have a remaining useful life of approximately 20 years, and developed technology and other have remaining useful lives ranging from approximately 1 year to approximately 11 years (weighted average of approximately 7 years). The weighted average remaining useful life of all definite-lived intangible assets as of December 31, 2017 , is approximately 19 years.

Amortization expense of intangible assets for the year ended December 31, 2017 , was $5.5 million ($5.2 million in 2016 ; $4.0 million in 2015). Accumulated amortization was $14.8 million and $9.3 million as of December 31, 2017 , and December 31, 2016 , respectively. Estimated amortization expense for definite-lived intangible assets is $5.3 million in 2018 , $5.0 million in 2019 , $4.7 million in 2020 , $4.6 million in 2021 , $4.3 million in 2022 and $37.1 million thereafter.

NOTE 8. INVESTMENTS

Investments. As of December 31, 2017 , the investment portfolio included the legacy real estate assets of ALLETE Properties, debt and equity securities consisting primarily of securities held in other postretirement plans to fund employee benefits, the cash equivalents within these plans and other assets consisting primarily of land in Minnesota.

Other Investments

As of December 31	2017	2016
Millions		
ALLETE Properties	$26.4	$31.7
Available-for-sale Securities *(a)*	19.1	18.8
Cash Equivalents	3.8	1.3
Other	3.8	3.8
Total Other Investments	$53.1	$55.6

(a) As of December 31, 2017 , the aggregate amount of available-for-sale corporate and governmental debt securities maturing in one year or less was $0.7 million , in one year to less than three years was $3.2 million , in three years to less than five years was $3.6 million , and in five or more years was $1.4 million .

Land Inventory. Land inventory is accounted for as held for use and is recorded at cost, unless the carrying value is determined not to be recoverable in accordance with the accounting standards for property, plant and equipment, in which case the land inventory is written down to estimated fair value. Land values are reviewed for indicators of impairment on a quarterly basis and no impairment was recorded in 2017 (none in 2016 ; $36.3 million in 2015). (See Note 1. Operations and Significant Accounting Policies.)

Available-for-Sale Securities. We account for our available-for-sale securities portfolio in accordance with the guidance for certain investments in debt and equity securities. Our available-for-sale securities portfolio consisted primarily of securities held in other postretirement plans to fund employee benefits.

Gross realized and unrealized gains and losses on our available-for-sale securities were immaterial in 2017 , 2016 and 2015 .

NOTE 9. FAIR VALUE

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. These inputs, which are used to measure fair value, are prioritized through the fair value hierarchy. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. This category includes primarily equity securities.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities. This category includes deferred compensation and fixed income securities.

Level 3 — Significant inputs that are generally less observable from objective sources. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value. This category includes the U.S. Water Services contingent consideration liability.

NOTE 9. FAIR VALUE (Continued)

The following tables set forth by level within the fair value hierarchy, our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2017 , and December 31, 2016 . Each asset and liability is classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of these assets and liabilities and their placement within the fair value hierarchy levels. The estimated fair value of Cash and Cash Equivalents listed on the Consolidated Balance Sheet approximates the carrying amount and therefore is excluded from the recurring fair value measures in the following tables.

	Fair Value as of December 31, 2017			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Investments *(a)*				
Available-for-sale – Equity Securities	$10.2	—	—	$10.2
Available-for-sale – Corporate and Governmental Debt Securities	—	$8.9	—	8.9
Cash Equivalents	3.8	—	—	3.8
Total Fair Value of Assets	$14.0	$8.9	—	$22.9
Liabilities: *(b)*				
Deferred Compensation	—	$18.2	—	$18.2
U.S. Water Services Contingent Consideration	—	—	$5.4	5.4
Total Fair Value of Liabilities	—	$18.2	$5.4	$23.6
Total Net Fair Value of Assets (Liabilities)	$14.0	$(9.3)	$(5.4)	$(0.7)

(a) Included in Other Investments on the Consolidated Balance Sheet.
(b) Included in Other Non-Current Liabilities on the Consolidated Balance Sheet.

	Fair Value as of December 31, 2016			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Investments *(a)*				
Available-for-sale – Equity Securities	$7.1	—	—	$7.1
Available-for-sale – Corporate and Governmental Debt Securities	—	$11.7	—	11.7
Cash Equivalents	1.3	—	—	1.3
Total Fair Value of Assets	$8.4	$11.7	—	$20.1
Liabilities: *(b)*				
Deferred Compensation	—	$16.0	—	$16.0
U.S. Water Services Contingent Consideration	—	—	$25.0	25.0
Total Fair Value of Liabilities	—	$16.0	$25.0	$41.0
Total Net Fair Value of Assets (Liabilities)	$8.4	$(4.3)	$(25.0)	$(20.9)

(a) Included in Other Investments on the Consolidated Balance Sheet.
(b) Included in Other Non-Current Liabilities on the Consolidated Balance Sheet.

NOTE 9. FAIR VALUE (Continued)

The following table provides a reconciliation of the beginning and ending balances of the U.S. Water Services Contingent Consideration measured at fair value using Level 3 measurements as of December 31, 2017 , and December 31, 2016 . The acquisition contingent consideration was recorded at the acquisition date at its estimated fair value. The acquisition date fair value was measured based on the consideration expected to be transferred, discounted to present value. The discount rate was determined at the time of measurement in accordance with generally accepted valuation methods. The fair value of the acquisition contingent consideration is remeasured to arrive at estimated fair value each reporting period with the change in fair value recognized as income or expense in the Consolidated Statement of Income. Changes to the fair value of the acquisition contingent consideration can result from changes in discount rates, timing of milestones that trigger payments, and the timing and amount of earnings estimates. Using different valuation assumptions, including earnings projections or discount rates, may result in different fair value measurements and expense (or income) in future periods. Management analyzes the fair value of the contingent liability on a quarterly basis and makes adjustments as appropriate. The acquisition contingent consideration was measured at $5.4 million as of December 31, 2017 .

Recurring Fair Value Measures

Activity in Level 3

Millions	
Balance as of December 31, 2015	$36.6
Accretion *(a)*	2.8
Payments	(0.8)
Changes in Cash Flow Projections *(b)*	(13.6)
Balance as of December 31, 2016	$25.0
Accretion *(a)*	0.8
Payments *(c)*	(19.7)
Changes in Cash Flow Projections *(c)*	(0.7)
Balance as of December 31, 2017	$5.4

(a) Included in Interest Expense on the Consolidated Statement of Income.

(b) During the fourth quarter of 2016, management assessed earnings estimates used in calculating the fair value of the U.S. Water Services contingent consideration liability and determined an adjustment was necessary to the liability's carrying amount based on its assessment. As a result, we recorded a reduction of $13.6 million to the liability's carrying amount which resulted in an after-tax gain of the same amount presented within Operating Expenses – Other in the Consolidated Statement of Income.

(c) Payments and changes in cash flow projections reflect the impact of a modification to the shareholder agreement in the first quarter of 2017 which provided participants a one-time election to sell shares at a determined price. Participants representing approximately half of the outstanding contingent consideration shares made the election, and were paid in the first half of 2017.

The Company's policy is to recognize transfers in and transfers out of Levels as of the actual date of the event or change in circumstances that caused the transfer. For the years ended December 31, 2017 and 2016 , there were no transfers in or out of Levels 1, 2 or 3.

Fair Value of Financial Instruments. With the exception of the item listed in the following table, the estimated fair value of all financial instruments approximates the carrying amount. The fair value for the item listed in the following table was based on quoted market prices for the same or similar instruments (Level 2).

Financial Instruments	**Carrying Amount**	**Fair Value**
Millions		
Long-Term Debt, Including Long-Term Debt Due Within One Year		
December 31, 2017	$1,513.3	$1,627.6
December 31, 2016	$1,569.1	$1,653.8

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis. Non-financial assets such as equity method investments, goodwill, intangible assets, and property, plant and equipment are measured at fair value when there is an indicator of impairment and recorded at fair value only when an impairment is recognized.

NOTE 9. FAIR VALUE (Continued)

Equity Method Investment. Our wholly-owned subsidiary, ALLETE Transmission Holdings, owns approximately 8 percent of ATC. (See Note 5. Investment in ATC.) The aggregate carrying amount of the investment was $118.7 million as of December 31, 2017 ($135.6 million as of December 31, 2016). The Company assesses our investment in ATC for impairment whenever events or changes in circumstances indicate that the carrying amount of our investment in ATC may not be recoverable. For the years ended December 31, 2017 and 2016 , there were no indicators of impairment.

Goodwill. The Company assesses the impairment of goodwill annually in the fourth quarter and whenever an event occurs or circumstances change that would indicate that the carrying amount may be impaired. The Company's goodwill is a result of the U.S. Water Services acquisition in 2015 as well as U.S. Water Services' subsequent acquisitions. (See Note 6. Acquisitions.) The aggregate carrying amount of goodwill was $148.3 million as of December 31, 2017 , and $131.2 million as of December 31, 2016 .

Impairment testing for goodwill is done at the reporting unit level. An impairment loss is recognized when the carrying amount of the reporting unit's net assets exceeds the estimated fair value of the reporting unit. The test for impairment requires us to make several estimates about fair value, most of which are based on projected future cash flows. The Company calculates the excess of the reporting unit's fair value over its carrying amount, including goodwill, utilizing a discounted cash flow analysis. Our annual impairment test for U.S. Water Services indicated that the estimated fair value of U.S. Water Services exceeded its carrying value, and no impairment existed for the year ended December 31, 2017 (none in 2016 and in 2015). As part of the 2016 annual impairment analysis, the Company recognized a non-cash impairment charge of $3.3 million for ALLETE Clean Energy's goodwill primarily related to the acquisition of Storm Lake II in 2014 . The charge, which is presented within Operating Expenses – Other in the Consolidated Statement of Income, eliminated all goodwill for the ALLETE Clean Energy reporting unit. (See Note 1. Operations and Significant Accounting Policies.)

Intangible Assets. The Company assesses indefinite-lived intangible assets for impairment annually in the fourth quarter. The Company also assesses indefinite-lived and definite-lived intangible assets whenever events or changes in circumstances indicate that the carrying amount of an intangible asset may not be recoverable. Substantially all of the Company's intangible assets are a result of the U.S. Water Services acquisition in 2015 as well as U.S. Water Services' subsequent acquisitions. The aggregate carrying amount of intangible assets was $77.6 million as of December 31, 2017 ($82.2 million as of December 31, 2016). When events or changes in circumstances indicate that the carrying amount of an intangible asset may not be recoverable, the Company calculates the excess of an intangible asset's carrying amount over its undiscounted future cash flows. If the carrying amount is not recoverable, an impairment loss is recorded based on the amount by which the carrying amount exceeds the fair value. The inputs used in the fair value analysis fall within Level 3 of the fair value hierarchy due to the use of significant unobservable inputs to determine fair value. As of December 31, 2017 , there have been no events or changes in circumstance which would indicate impairment of our intangible assets.

Property, Plant and Equipment. The Company assesses the impairment of property, plant, and equipment whenever events or changes in circumstances indicate that the carrying amount of property, plant, and equipment assets may not be recoverable. The impairment of ALLETE Clean Energy's goodwill in 2016 , primarily due to lower estimated energy prices in periods not under PSAs, caused management to review ALLETE Clean Energy's WTGs for impairment. Based on the results of the undiscounted cash flow analysis, the undiscounted future cash flows were adequate to recover the carrying value of the WTGs. In 2015 , the Company implemented a revised strategy for its real estate assets and recorded a non-cash impairment charge of $36.3 million for ALLETE Properties, reducing the carrying value of the real estate to its estimated fair value. (See Note 1. Operations and Significant Accounting Policies.) For the year ended December 31, 2017 , there were no indicators of impairment.

We believe that long-standing ratemaking practices approved by applicable state and federal regulatory commissions allow for the recovery of the remaining book value of retired plant assets. In 2015, Minnesota Power retired Taconite Harbor Unit 3 and converted Laskin to operate on natural gas which were actions included in Minnesota Power's MPUC-approved 2013 IRP. In a July 2016 order, the MPUC approved Minnesota Power's 2015 IRP with modifications. The 2015 IRP contains steps in Minnesota Power's *EnergyForward* plan including the economic idling of Taconite Harbor Units 1 and 2 in September 2016, and the ceasing of coal-fired operations at Taconite Harbor in 2020. (See Note 4. Regulatory Matters.) The MPUC order for the 2015 IRP also directed Minnesota Power to retire Boswell Units 1 and 2 no later than 2022. In October 2016, Minnesota Power announced that Boswell Units 1 and 2 will be retired in 2018. We do not expect to record any impairment charge as a result of the retirement of Taconite Harbor Unit 3, the ceasing of coal-fired operations at Taconite Harbor Units 1 and 2, or the conversion of Laskin to operate on natural gas. In addition, we expect to be able to continue depreciating these assets for at least their established remaining useful lives; however, we are unable to predict the impact of regulatory outcomes resulting in changes to their established remaining useful lives.

NOTE 10. SHORT-TERM AND LONG-TERM DEBT

Short-Term Debt. As of December 31, 2017 , total short-term debt outstanding was $64.1 million ($187.7 million as of December 31, 2016), consisted of long-term debt due within one year and included $0.5 million of unamortized debt issuance costs.

As of December 31, 2017 , we had consolidated bank lines of credit aggregating $407.0 million ($409.0 million as of December 31, 2016), the majority of which expire in October 2020. We had $11.9 million outstanding in standby letters of credit and no outstanding draws under our lines of credit as of December 31, 2017 ($11.1 million in standby letters of credit and no outstanding draws as of December 31, 2016).

Long-Term Debt. As of December 31, 2017 , total long-term debt outstanding was $1,439.2 million ($1,370.4 million as of December 31, 2016) and included $9.5 million of unamortized debt issuance costs. The aggregate amount of long-term debt maturing in 2018 is $64.6 million ; $57.6 million in 2019 ; $143.0 million in 2020 ; $97.8 million in 2021 ; $88.0 million in 2022 ; and $1,062.3 million thereafter. Substantially all of our regulated electric plant is subject to the lien of the mortgages collateralizing outstanding first mortgage bonds. The mortgages contain non-financial covenants customary in utility mortgages, including restrictions on our ability to incur liens, dispose of assets, and merge with other entities.

Minnesota Power is obligated to make financing payments for the Camp Ripley solar array totaling $1.4 million annually during the financing term, which expires in 2027. Minnesota Power has the option at the end of the financing term to renew for a two -year term, or to purchase the solar array for approximately $4 million . Minnesota Power anticipates exercising the purchase option when the term expires.

On June 1, 2017, ALLETE issued $80.0 million of its senior unsecured notes (the Notes) to certain institutional buyers in the private placement market. The Notes were issued in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended, to institutional accredited investors. The Notes bear interest at 3.11 percent and mature on June 1, 2027. Interest on the Notes is payable semi-annually in June and December of each year, commencing on December 1, 2017. ALLETE has the option to prepay all or a portion of the Notes at its discretion, subject to a make-whole provision. The Notes are subject to additional terms and conditions which are customary for these types of transactions. Proceeds from the sale of the Notes were used to redeem debt, fund corporate growth opportunities and for general corporate purposes.

On August 25, 2017, ALLETE entered into a $40.0 million term loan agreement (Term Loan). The Term Loan is an unsecured, single draw loan that is due on August 25, 2020, and may be prepaid at any time subject to a make-whole provision. Interest on the Term Loan is payable quarterly at a rate per annum equal to LIBOR plus 1.025 percent . Proceeds from the Term Loan were used for general corporate purposes.

On November 2, 2017, ALLETE entered into a bond purchase agreement providing for the issuance and sale of $60.0 million of its First Mortgage Bonds (the Bonds) that bear interest at 4.07 percent . The Bonds will be issued on or about April 1, 2018, and will mature in April 2048. Interest on the Bonds will be payable semi-annually in April and October of each year, commencing on October 16, 2018. ALLETE has the option to prepay all or a portion of the Bonds at its discretion, subject to a make-whole provision. The Bonds are subject to additional terms and conditions which are customary for these types of transactions. The company intends to use the proceeds from the sale of the Bonds to fund utility capital expenditures and for general corporate purposes. The Bonds were sold in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended, to institutional accredited investors.

NOTE 10. SHORT-TERM AND LONG-TERM DEBT (Continued)
Long-Term Debt (Continued)

Long-Term Debt

As of December 31	2017	2016
Millions		
First Mortgage Bonds		
1.83% Series Due 2018	$50.0	$50.0
8.17% Series Due 2019	42.0	42.0
5.28% Series Due 2020	35.0	35.0
2.80% Series Due 2020	40.0	40.0
4.85% Series Due 2021	15.0	15.0
3.02% Series Due 2021	60.0	60.0
3.40% Series Due 2022	75.0	75.0
6.02% Series Due 2023	75.0	75.0
3.69% Series Due 2024	60.0	60.0
4.90% Series Due 2025	30.0	30.0
5.10% Series Due 2025	30.0	30.0
3.20% Series Due 2026	75.0	75.0
5.99% Series Due 2027	60.0	60.0
3.30% Series Due 2028	40.0	40.0
3.74% Series Due 2029	50.0	50.0
3.86% Series Due 2030	60.0	60.0
5.69% Series Due 2036	50.0	50.0
6.00% Series Due 2040	35.0	35.0
5.82% Series Due 2040	45.0	45.0
4.08% Series Due 2042	85.0	85.0
4.21% Series Due 2043	60.0	60.0
4.95% Series Due 2044	40.0	40.0
5.05% Series Due 2044	40.0	40.0
4.39% Series Due 2044	50.0	50.0
Unsecured Term Loan Variable Rate Due 2017	—	125.0
Senior Unsecured Notes 5.99% Due 2017	—	50.0
Variable Demand Revenue Refunding Bonds Series 1997 A Due 2020	13.5	13.5
Unsecured Term Loan Variable Rate Due 2020	40.0	—
Armenia Mountain Senior Secured Notes 3.26% Due 2024	65.9	74.6
Industrial Development Variable Rate Demand Refunding Revenue Bonds Series 2006, Due 2025	27.8	27.8
Senior Unsecured Notes 3.11% Due 2027	80.0	—
SWL&P First Mortgage Bonds 4.15% Series Due 2028	15.0	15.0
Other Long-Term Debt, 3.11% – 5.37% Due 2018 – 2037	69.1	61.2
Unamortized Debt Issuance Costs	(10.0)	(11.0)
Total Long-Term Debt	1,503.3	1,558.1
Less: Due Within One Year	64.1	187.7
Net Long-Term Debt	$1,439.2	$1,370.4

NOTE 10. SHORT-TERM AND LONG-TERM DEBT (Continued)

Financial Covenants. Our long-term debt arrangements contain customary covenants. In addition, our lines of credit and letters of credit supporting certain long-term debt arrangements contain financial covenants. Our compliance with financial covenants is not dependent on debt ratings. The most restrictive financial covenant requires ALLETE to maintain a ratio of indebtedness to total capitalization (as the amounts are calculated in accordance with the respective long-term debt arrangements) of less than or equal to 0.65 to 1.00 , measured quarterly. As of December 31, 2017 , our ratio was approximately 0.42 to 1.00 . Failure to meet this covenant would give rise to an event of default if not cured after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. ALLETE has no significant restrictions on its ability to pay dividends from retained earnings or net income. As of December 31, 2017 , ALLETE was in compliance with its financial covenants.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES

The following table details the estimated minimum payments for certain long-term commitments:

As of December 31, 2017

Millions	2018	2019	2020	2021	2022	Thereafter
Coal, Rail and Shipping Contracts	$29.0	$1.8	—	—	—	—
Leasing Agreements	$14.2	$12.8	$9.5	$7.3	$6.1	$30.0
Long-term Service Agreements *(a)*	$11.0	$0.9	—	—	$1.0	$11.0
PPAs *(b)*	$104.5	$107.1	$115.0	$144.8	$144.7	$1,667.0

(a) Consists of long-term service agreements for wind energy facilities.

(b) Does not include the agreement with Manitoba Hydro expiring in 2022, as this contract is for surplus energy only; Oliver Wind I and Oliver Wind II, as Minnesota Power only pays for energy as it is delivered; and the agreement with Tenaska commencing in 2020 as it is subject to approval of the construction of a 525 MW to 550 MW combined-cycle natural gas-fired facility. (See Power Purchase Agreements.)

Coal, Rail and Shipping Contracts. Minnesota Power has coal supply agreements providing for the purchase of a significant portion of its coal requirements through December 2018 and a portion of its coal requirements through December 2021. Minnesota Power also has coal transportation agreements in place for the delivery of a significant portion of its coal requirements through December 2018. The costs of fuel and related transportation costs for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

Leasing Agreements. BNI Energy is obligated to make lease payments for a dragline totaling $2.8 million annually during the lease term, which expires in 2027. BNI Energy has the option at the end of the lease term to renew the lease at fair market value, to purchase the dragline at fair market value, or to surrender the dragline and pay a $3.0 million termination fee. We also lease other properties and equipment under operating lease agreements with a majority of terms expiring through 2024. Total lease expense was $17.5 million in 2017 ($17.1 million in 2016 ; $17.3 million in 2015).

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

Power Purchase Agreements. Our long-term PPAs have been evaluated under the accounting guidance for variable interest entities. We have determined that either we have no variable interest in the PPAs, or where we do have variable interests, we are not the primary beneficiary; therefore, consolidation is not required. These conclusions are based on the fact that we do not have both control over activities that are most significant to the entity and an obligation to absorb losses or receive benefits from the entity's performance. Our financial exposure relating to these PPAs is limited to our capacity and energy payments.

Square Butte PPA. Minnesota Power has a PPA with Square Butte that extends through 2026 (Agreement). Minnesota Power is obligated to pay its pro rata share of Square Butte's costs based on its entitlement to the output of Square Butte's 455 MW coal-fired generating unit. Minnesota Power's output entitlement under the Agreement is 50 percent for the remainder of the Agreement, subject to the provisions of the Minnkota Power PSA described in the following table. Minnesota Power's payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's costs consist primarily of debt service, operating and maintenance, depreciation and fuel expenses. As of December 31, 2017 , Square Butte had total debt outstanding of $330.0 million . Annual debt service for Square Butte is expected to be approximately $49 million in each of the next five years, 2018 through 2022 , of which Minnesota Power's obligation is 50 percent. Fuel expenses are recoverable through Minnesota Power's fuel adjustment clause and include the cost of coal purchased from BNI Energy under a long-term contract.

Minnesota Power's cost of power purchased from Square Butte during 2017 was $75.7 million ($73.3 million in 2016 ; $77.8 million in 2015). This reflects Minnesota Power's pro rata share of total Square Butte costs based on the 50 percent output entitlement. Included in this amount was Minnesota Power's pro rata share of interest expense of $9.4 million in 2017 ($9.6 million in 2016 ; $10.1 million in 2015). Minnesota Power's payments to Square Butte are approved as a purchased power expense for ratemaking purposes by both the MPUC and the FERC.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Power Purchase Agreements (Continued)

Minnesota Power has also entered into the following agreements for the purchase or sale of capacity and energy as of December 31, 2017 :

Counterparty	Quantity	Product	Commencement	Expiration	Pricing
PPAs					
Great River Energy					
PPA 1	50 MW	Capacity / Energy	June 2016	May 2020	*(a)*
PPA 2	50 MW	Capacity	June 2016	May 2020	Fixed
PPA 3	50 MW	Capacity	June 2017	May 2020	Fixed
Manitoba Hydro					
PPA 1	*(b)*	Energy	May 2011	April 2022	Forward Market Prices
PPA 2	50 MW	Capacity / Energy	June 2015	May 2020	*(c)*
PPA 3	50 MW	Capacity	June 2017	May 2020	Fixed
PPA 4 *(d)*	250 MW	Capacity / Energy	June 2020	May 2035	*(e)*
PPA 5 *(d)*	133 MW	Energy	*(f)*	*(f)*	Forward Market Prices
Minnkota Power	50 MW	Capacity / Energy	June 2016	May 2020	*(g)*
Oliver Wind I	*(h)*	Energy	December 2006	December 2031	Fixed
Oliver Wind II	*(h)*	Energy	December 2007	December 2032	Fixed
Shell Energy	50 MW	Energy	January 2017	December 2019	Fixed
TransAlta	*(i)*	Energy	January 2017	December 2019	Fixed
Tenaska *(j)*	*(j)*	Capacity / Energy	June 2020	June 2040	Fixed
PSAs					
Basin					
PSA 1	100 MW	Capacity / Energy	May 2010	April 2020	*(k)*
PSA 2	100 MW	Capacity	June 2016	May 2018	Fixed
PSA 3	50 MW	Capacity	June 2017	May 2019	Fixed
Minnkota Power	*(l)*	Capacity / Energy	June 2014	December 2026	*(l)*
Silver Bay Power	*(m)*	Energy	January 2017	December 2031	*(n)*

(a) The capacity price is fixed and the energy price is based on a formula that includes an annual fixed price component adjusted for changes in a natural gas index, as well as market prices.

(b) The energy purchased consists primarily of surplus hydro energy on Manitoba Hydro's system and is delivered on a non-firm basis. Minnesota Power will purchase at least one million MWh of energy over the contract term.

(c) The capacity and energy prices are adjusted annually by the change in a governmental inflationary index.

(d) Agreements are subject to the construction of additional transmission capacity between Manitoba and the U.S., along with construction of new hydroelectric generating capacity in Manitoba. (See Great Northern Transmission Line.)

(e) The capacity price is adjusted annually until 2020 by the change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed component adjusted for the change in a governmental inflationary index and a natural gas index, as well as market prices.

(f) The contract term shall be the 20 -year period beginning on the in-service date for the GNTL. (See Great Northern Transmission Line.)

(g) The agreement includes a fixed capacity charge and energy prices that escalate at a fixed rate annually over the term.

(h) The PPAs provide for the purchase of all output from the 50 MW Oliver Wind I and 48 MW Oliver Wind II wind energy facilities.

(i) The energy purchased under the 50 MW PPA is during off-peak hours and the 100 MW PPA is during on-peak hours.

(j) The PPA provides for the purchase of all output from a 250 MW wind energy facility to be constructed in southwest Minnesota and is subject to approval of the construction of a 525 MW to 550 MW combined-cycle natural gas-fired facility. (See Note 4. Regulatory Matters.)

(k) The capacity charge is based on a fixed monthly schedule with a minimum annual escalation provision. The energy charge is based on a fixed monthly schedule and provides for annual escalation based on the cost of fuel. The agreement also allows Minnesota Power to recover a pro rata share of increased costs related to emissions that occur during the last five years of the contract.

(l) Minnesota Power is selling a portion of its entitlement from Square Butte to Minnkota Power, resulting in Minnkota Power's net entitlement increasing and Minnesota Power's net entitlement decreasing until Minnesota Power's share is eliminated at the end of 2025 . Of Minnesota Power's 50 percent output entitlement, it sold to Minnkota Power approximately 28 percent in 2017 (28 percent in 2016 and in 2015). (See Square Butte PPA.)

(m) Silver Bay Power supplies approximately 90 MW of load to Northshore Mining, an affiliate of Silver Bay Power, which has been served predominately through self-generation by Silver Bay Power. In the years 2016 through 2019, Minnesota Power is supplying Silver Bay Power with at least 50 MW of energy and Silver Bay Power has the option to purchase additional energy. On December 31, 2019, Silver Bay Power will cease self-generation and Minnesota Power will supply the energy requirements for Silver Bay Power.

(n) The energy pricing is fixed through 2019 with pricing in later years escalating at a fixed rate annually and adjusted for changes in a natural gas index.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

Transmission . We continue to make investments in transmission opportunities that strengthen or enhance the transmission grid or take advantage of our geographical location between sources of renewable energy and end users. These include the GNTL, investments to enhance our own transmission facilities, investments in other transmission assets (individually or in combination with others) and our investment in ATC.

Great Northern Transmission Line. As a condition of the 250 MW long-term PPA entered into with Manitoba Hydro, construction of additional transmission capacity is required. As a result, Minnesota Power and Manitoba Hydro proposed construction of the GNTL, an approximately 220 -mile 500 -kV transmission line between Manitoba and Minnesota's Iron Range in order to strengthen the electric grid, enhance regional reliability and promote a greater exchange of sustainable energy.

In 2015, a certificate of need was approved by the MPUC. Based on this approval, Minnesota Power's portion of the investments and expenditures for the project are eligible for cost recovery under its existing transmission cost recovery rider and are anticipated to be included in future transmission cost recovery filings. (See Note 4. Regulatory Matters.) Also in 2015, the FERC approved our request to recover on construction work in progress related to the GNTL from Minnesota Power's wholesale customers. In an April 2016 order, the MPUC approved the route permit for the GNTL which largely follows Minnesota Power's preferred route, including the international border crossing, and in November 2016, the U.S. Department of Energy issued a presidential permit to cross the U.S.-Canadian border, which was the final major regulatory approval needed before construction in the U.S. could begin. Site clearing and pre-construction activities commenced in the first quarter of 2017 with construction expected to be completed in 2020. Total project cost in the U.S., including substation work, is estimated to be between $560 million and $710 million , of which Minnesota Power's portion is expected to be between $300 million and $350 million ; the difference will be recovered from a subsidiary of Manitoba Hydro as contributions in aid of construction. Total project costs of $152.4 million have been incurred through December 31, 2017 , of which $67.6 million has been recovered from a subsidiary of Manitoba Hydro.

Manitoba Hydro must obtain regulatory and governmental approvals related to a new transmission line in Canada. In 2015, Manitoba Hydro submitted the final preferred route and EIS for the transmission line in Canada to the Manitoba Conservation and Water Stewardship for regulatory approval. In December 2016, Manitoba Hydro filed an application with the National Energy Board in Canada requesting authorization to construct and operate an international transmission line. Both provincial and federal approvals are pending. Construction of Manitoba Hydro's hydroelectric generation facility commenced in 2014 and is anticipated to be in service by early 2021.

Environmental Matters.

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. A number of regulatory changes to the Clean Air Act, the Clean Water Act and various waste management requirements have recently been promulgated by both the EPA and state authorities. Minnesota Power's facilities are subject to additional requirements under many of these regulations. Minnesota Power is reshaping its generation portfolio, over time, to reduce its reliance on coal, has installed cost-effective emission control technology and advocates for sound science and policy during rulemaking implementation.

We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits have been obtained. We anticipate that with many state and federal environmental regulations finalized, or to be finalized in the near future, potential expenditures for future environmental matters may be material and may require significant capital investments. Minnesota Power has evaluated various environmental compliance scenarios using possible outcomes of environmental regulations to project power supply trends and impacts on customers.

We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated based on current law and existing technologies. Accruals are adjusted as assessment and remediation efforts progress, or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in the Consolidated Balance Sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are expensed unless recoverable in rates from customers.

Air. The electric utility industry is regulated both at the federal and state level to address air emissions. Minnesota Power's generating facilities mainly burn low-sulfur western sub-bituminous coal. All of Minnesota Power's coal-fired generating facilities are equipped with pollution control equipment such as scrubbers, baghouses and low NO x technologies. Under currently applicable environmental regulations, these facilities are substantially compliant with emission requirements.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

New Source Review (NSR). In 2008, Minnesota Power received a Notice of Violation (NOV) from the EPA asserting violations of the NSR requirements of the Clean Air Act at Boswell and Laskin Unit 2 between the years of 1981 and 2001. Minnesota Power received an additional NOV in 2011 alleging that two projects undertaken at Rapids Energy Center in 2004 and 2005 should have been reviewed under the NSR requirements and that the Rapids Energy Center's Title V permit was violated. Minnesota Power reached a settlement with the EPA regarding these NOVs and entered into a Consent Decree which was approved by the U.S. District Court for the District of Minnesota in 2014. The Consent Decree provided for, among other requirements, more stringent emissions limits at all affected units, the option of refueling, retrofitting or retiring certain small coal units, and the addition of 200 MW of wind energy. Provisions of the Consent Decree require that, by no later than December 31, 2018, Boswell Units 1 and 2 must be retired, refueled, repowered, or emissions rerouted through existing emission control technology at Boswell. In October 2016, Minnesota Power announced that Boswell Units 1 and 2 will be retired in 2018 as part of its *EnergyForward* strategic plan. We believe that costs to retire Boswell Units 1 and 2 will be eligible for recovery in rates over time, subject to regulatory approval in a rate proceeding.

Cross-State Air Pollution Rule (CSAPR). The CSAPR requires certain states in the eastern half of the U.S., including Minnesota, to reduce power plant emissions that contribute to ozone or fine particulate pollution in other states. The CSAPR does not require installation of controls; rather it requires facilities have sufficient allowances to cover their emissions on an annual basis. These allowances are allocated to facilities from each state's annual budget, and can be bought and sold. Based on our review of the NO_x and SO_2 allowances issued and pending issuance, we currently expect generation levels and emission rates will result in continued compliance with the CSAPR.

Mercury and Air Toxics Standards (MATS) Rule. Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for hazardous air pollutants (HAPs) for certain source categories. The final MATS rule addressed such emissions from coal-fired utility units greater than 25 MW and established categories of HAPs, including mercury, trace metals other than mercury, and acid gases. The EPA established emission limits for these categories of HAPs and work practice standards for the remaining categories. Construction on the project to implement the Boswell Unit 4 mercury emissions reduction plan to position the unit for MATS compliance was completed in 2015. Investments and compliance work previously completed at Boswell Unit 3, including emission reduction investments completed in 2009, meet the requirements of the MATS rule. The conversion of Laskin Units 1 and 2 to operate on natural gas in 2015 positioned those units for MATS compliance.

Minnesota Mercury Emissions Reduction Act/Rule. Minnesota Power was required to implement a mercury emissions reduction project for Boswell Unit 4 by December 31, 2018. The Boswell Unit 4 environmental upgrade discussed above (see *Mercury and Air Toxics Standards (MATS) Rule*) fulfills the requirements of the Minnesota Mercury Emissions Reduction Act.

National Ambient Air Quality Standards (NAAQS). The EPA is required to review the NAAQS every five years. If the EPA determines that a state's air quality is not in compliance with the NAAQS, the state is required to adopt plans describing how it will reduce emissions to attain the NAAQS. Four NAAQS have either recently been revised or are currently proposed for revision, as described below.

- *Ozone NAAQS.* All areas of Minnesota currently meet the new standard based on the most recent available ambient monitoring data; however, some areas in the metropolitan Twin Cities and southwest portion of the state are close to exceeding the standard. As a result, voluntary efforts to reduce ground-level ozone continue in the state. No additional costs for compliance are anticipated at this time.

- *Particulate Matter NAAQS.* The EPA has designated the entire state of Minnesota as unclassifiable/attainment; however, Minnesota sources may ultimately be required to reduce their emissions to assist with attainment in neighboring states. In September 2016, environmental groups filed a lawsuit against the EPA in the U.S. District Court for the Northern District of California alleging the EPA had failed to fully implement the $PM_{2.5}$ standards in certain states, including Minnesota, by not enforcing states' submittals of required infrastructure implementation plans for the 2012 $PM_{2.5}$ NAAQS. The outcome of this litigation is uncertain, and as such, any costs for complying with the final Particulate Matter NAAQS cannot be estimated at this time.

- *NO_2 NAAQS.* Ambient monitoring data indicates that Minnesota is likely in compliance with the one-hour NAAQS standard for NO_2 . On July 16, 2017, the EPA proposed retaining the current one-hour and annual NO_2 NAAQS. Additional compliance costs for the one-hour NO_2 NAAQS are not expected at this time.

- *SO_2 NAAQS.* In 2015, the EPA finalized the SO_2 data requirements rule (DRR) for the 2010 one-hour NAAQS to assist the states in implementing the standard. The MPCA initially informed Minnesota Power that compliant SO_2 modeling completed at Minnesota Power's Boswell and Taconite Harbor facilities would satisfy the DRR obligations and no further modeling would be required; however, the DRR also require facilities have federally-enforceable permit limits at which the one-hour SO_2 NAAQS compliance was modeled by January 13, 2017. Taconite Harbor was issued an amended air permit in September 2016, containing the new modeling limits at that facility. The MPCA did not meet the January 13, 2017, deadline to amend the Boswell permit. The MPCA is in discussions with the EPA on alternate compliance pathways to use existing completed modeling at current limits. On August 21, 2017, the EPA proposed retaining the current primary SO_2 one-hour NAAQS. Compliance costs for the one-hour SO_2 NAAQS are not expected to be material.

Climate Change. The scientific community generally accepts that emissions of GHG are linked to global climate change which creates physical and financial risks. Physical risks could include, but are not limited to: increased or decreased precipitation and water levels in lakes and rivers; increased temperatures; and changes in the intensity and frequency of extreme weather events. These all have the potential to affect the Company's business and operations. We are addressing climate change by taking the following steps that also ensure reliable and environmentally compliant generation resources to meet our customers' requirements:

- Expanding our renewable power supply;
- Providing energy conservation initiatives for our customers and engaging in other demand side management efforts;
- Improving efficiency of our generating facilities;
- Supporting research of technologies to reduce carbon emissions from generating facilities and carbon sequestration efforts; and
- Evaluating and developing less carbon intensive future generating assets such as efficient and flexible natural gas-fired generating facilities.

EPA Regulation of GHG Emissions. In 2010, the EPA issued the Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). The Tailoring Rule establishes permitting thresholds required to address GHG emissions for new facilities, existing facilities that undergo major modifications and other facilities characterized as major sources under the Clean Air Act's Title V program. For our existing facilities, the rule does not require amending our existing Title V operating permits to include GHG requirements, however, GHG requirements may be added to our existing Title V operating permits by the MPCA as these permits are renewed or amended.

In 2014, the U.S. Supreme Court invalidated the aspect of the Tailoring Rule that established higher permitting thresholds for GHG than for other pollutants subject to PSD; however, the court also upheld the EPA's ability to require best available control technology (BACT) for GHG from sources already subject to regulation under PSD. Minnesota Power's coal-fired generating facilities are already subject to regulation under PSD, so we anticipate that ultimately PSD for GHG will apply to our facilities, but the timing of the promulgation of a replacement for the Tailoring Rule is uncertain. The PSD applies to existing facilities only when they undertake a major modification that increases emissions.

In October 2016, the EPA published a proposed rule in the Federal Register to revise its PSD and Title V regulatory provisions concerning GHG emissions. In this proposed rule, the EPA proposes to amend its regulations to clarify that a source's obligation to obtain a PSD or Title V permit is triggered only by non-GHG pollutants. If the PSD or Title V permitting requirements are triggered by non-GHG, NSR pollutants, then these programs will also apply to the source's GHG emissions. The proposed rule, as currently written, is not expected to have a material impact on the Title V permitting for current operations.

In 2014, the EPA announced a proposed rule under Section 111(d) of the Clean Air Act for existing power plants entitled "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units", also referred to as the Clean Power Plan (CPP). The EPA issued the final CPP in 2015, together with a proposed federal implementation plan and a model rule for emissions trading. In February 2016, the U.S. Supreme Court issued an order staying the effectiveness of the rule until after the appellate court process is complete. In September 2016, the U.S. Court of Appeals for the District of Columbia heard oral arguments and is currently deliberating. If the CPP is upheld at the completion of the appellate process, all of the CPP regulatory deadlines are expected to be reset based on the length of time that the appeals process takes. The EPA is precluded from enforcing the CPP while the U.S. Supreme Court stay is in force; however, the MPCA has been holding a series of meetings on the CPP for educational and planning purposes in the interim. Minnesota Power has been actively involved in these MPCA meetings, and is closely monitoring the appeals process.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

If upheld, the CPP would establish uniform CO_2 emission performance rates for existing fossil fuel-fired and natural gas-fired combined cycle generating units, setting state-specific goals for CO_2 emissions from the power sector. State goals were determined based on CPP source-specific performance emission rates and each state's mix of power plants. The EPA has filed a motion with the U.S. Court of Appeals for the District of Columbia Circuit to hold CPP-related litigation in suspension while the EPA is reviewing the rule. On October 10, 2017, the EPA issued a notice of proposed rulemaking, proposing to repeal the CPP. On December 28, 2017, an Advanced Notice of Proposed Rulemaking (ANPRM) for a CPP replacement rule was published in the Federal Register.

Minnesota Power is currently evaluating the CPP rescission and recently proposed ANPRM for a CPP replacement rule as it relates to the State of Minnesota as well as its potential impact on the Company. Minnesota has already initiated several measures consistent with those called for under the CPP. Minnesota Power is implementing its *EnergyForward* strategic plan that provides for significant emission reductions and diversifying its electricity generation mix to include more renewable and natural gas energy. (See Note 4. Regulatory Matters.)

We are unable to predict the GHG emission compliance costs we might incur; however, the costs could be material. Minnesota Power would seek recovery of additional costs through a rate proceeding.

Water. The Clean Water Act requires National Pollutant Discharge Elimination System (NPDES) permits be obtained from the EPA (or, when delegated, from individual state pollution control agencies) for any wastewater discharged into navigable waters. We have obtained all necessary NPDES permits, including NPDES storm water permits for applicable facilities, to conduct our operations.

Clean Water Act - Aquatic Organisms. In 2014, EPA regulations under Section 316(b) of the Clean Water Act setting standards applicable to cooling water intake structures for the protection of aquatic organisms became effective. The regulations require existing large power plants and manufacturing facilities that withdraw greater than 25 percent of water from adjacent water bodies for cooling purposes and have a design intake flow of greater than 2 million gallons per day, to limit the number of aquatic organisms that are impacted by the facility's intake structure or cooling system. The Section 316(b) rule will be implemented through NPDES permits issued to covered facilities. No NPDES permits for Minnesota Power facilities have been re-issued containing Section 316(b) requirements since the final rule became effective. Should the MPCA require significant modifications to Minnesota Power's intake structures, a preliminary assessment indicates that Minnesota Power could incur costs of compliance up to $15 million over the next five years. Minnesota Power would seek recovery of additional costs through a rate proceeding.

Steam Electric Power Generating Effluent Guidelines. In 2015, the EPA issued revised federal effluent limit guidelines (ELG) for steam electric power generating stations under the Clean Water Act. It set effluent limits and prescribed BACT for several wastewater streams, including flue gas desulphurization (FGD) water, bottom ash transport water and coal combustion landfill leachate. On September 13, 2017, the EPA announced a two-year postponement of the ELG compliance date of November 1, 2018, to November 1, 2020, while the agency reconsiders bottom ash transport water and FGD wastewater provisions.

The final ELG rule's potential impact on Minnesota Power operations is primarily at Boswell. Boswell currently discharges bottom ash contact water through its NPDES permit, and also has a closed-loop FGD system that does not discharge, but may do so in the future. Under the existing ELG rule, bottom ash transport water discharge must cease no later than December 31, 2023. Bottom ash contact water will either need to be re-used in a closed-loop process, routed to a FGD scrubber, or the bottom ash handling system will need to be converted to a dry process. If FGD wastewater is discharged in the future, it will require additional wastewater treatment. The ELG rule provision regarding these two waste-streams are being reconsidered and may change prior to November 1, 2020. Efforts have been underway at Boswell for several years to reduce the amount of water discharged and evaluate potential re-use options in its plant processes.

At this time, we cannot estimate what compliance costs we might incur related to these or other potential future water discharge regulations; however, the costs could be material, including costs associated with retrofits for bottom ash handling, pond dewatering, pond closure, and wastewater treatment and reuse. Minnesota Power would seek recovery of additional costs through a rate proceeding.

Solid and Hazardous Waste. The Resource Conservation and Recovery Act of 1976 regulates the management and disposal of solid and hazardous wastes. We are required to notify the EPA of hazardous waste activity and, consequently, routinely submit the necessary reports to the EPA.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

Coal Ash Management Facilities. Minnesota Power stores or disposes coal ash at four of its electric generating facilities by the following methods: storing ash in lined onsite impoundments (ash ponds), disposing of dry ash in a lined dry ash landfill which has been idled and has a temporary landfill cover in place, applying ash to land as an approved beneficial use and trucking ash to state permitted landfills.

Coal Combustion Residuals from Electric Utilities (CCR). In 2015, the EPA published the final rule regulating CCR as nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA) in the Federal Register. The rule includes additional requirements for new landfill and impoundment construction as well as closure activities related to certain existing impoundments. Costs of compliance for Boswell and Laskin are expected to occur primarily over the next 10 years and be between approximately $65 million and $100 million . The EPA has indicated to Minnesota Power that the Taconite Harbor landfill is a CCR unit, based on the EPA's interpretation of the CCR rule language. Minnesota Power has agreed to post the required CCR information for the Taconite Harbor landfill on Minnesota Power's website while the CCR issue is resolved. Minnesota Power continues to work on minimizing costs through evaluation of beneficial re-use and recycling of CCR and CCR-related waters. On September 13, 2017, the EPA announced its intention to formally reconsider the CCR rule under Subtitle D of the RCRA. Compliance costs, if any, for CCR at Taconite Harbor cannot be estimated at this time. Minnesota Power would seek recovery of additional costs through a rate proceeding.

Other Environmental Matters

Manufactured Gas Plant Site. We are reviewing and addressing environmental conditions at a former manufactured gas plant site located in Superior, Wisconsin, and formerly operated by SWL&P. SWL&P has been working with the Wisconsin Department of Natural Resources (WDNR) in determining the extent and location of contamination at the site and surrounding properties. In December 2017, the WDNR authorized SWL&P to transition from site investigation into the remedial design process. As of December 31, 2017 , we have recorded a liability of approximately $8 million for remediation costs at this site, and a corresponding regulatory asset as we expect recovery of these remediation costs to be allowed by the PSCW. We expect to incur these costs over the next four years.

Other Matters

ALLETE Clean Energy. ALLETE Clean Energy's wind energy facilities have PSAs in place for their entire output and expire in various years between 2018 and 2032. As of December 31, 2017 , ALLETE Clean Energy has $15.4 million outstanding in standby letters of credit.

U.S. Water Services. As of December 31, 2017 , U.S. Water Services has $0.8 million outstanding in standby letters of credit.

BNI Energy. As of December 31, 2017 , BNI Energy had surety bonds outstanding of $49.9 million and a letter of credit for an additional $0.6 million related to the reclamation liability for closing costs associated with its mine and mine facilities. Although its coal supply agreements obligate the customers to provide for the closing costs, additional assurance is required by federal and state regulations. BNI Energy's total reclamation liability is currently estimated at $47.5 million . BNI Energy does not believe it is likely that any of these outstanding surety bonds or the letter of credit will be drawn upon.

ALLETE Properties. As of December 31, 2017 , ALLETE Properties had surety bonds outstanding and letters of credit to governmental entities totaling $8.6 million primarily related to development and maintenance obligations for various projects. The estimated cost of the remaining development work is $6.1 million . ALLETE Properties does not believe it is likely that any of these outstanding surety bonds or letters of credit will be drawn upon.

NOTE 11. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Other Matters (Continued)

Community Development District Obligations. In 2005, the Town Center District issued $26.4 million of tax-exempt, 6.0 percent capital improvement revenue bonds, and in 2006, the Palm Coast Park District issued $31.8 million of tax-exempt, 5.7 percent special assessment bonds. The capital improvement revenue bonds and the special assessment bonds are payable over 31 years (by May 1, 2036 and 2037, respectively) and are secured by special assessments on the benefited land. The bond proceeds were used to pay for the construction of a portion of the major infrastructure improvements in each district and to mitigate traffic and environmental impacts. The assessments were billed to the landowners beginning in 2006 for the Town Center District and 2007 for the Palm Coast Park District. To the extent that ALLETE Properties still owns land at the time of the assessment, it will incur the cost of our portion of these assessments, based upon its ownership of benefited property. As of December 31, 2017 , we owned 70 percent of the assessable land in the Town Center District (72 percent as of December 31, 2016) and 33 percent of the assessable land in the Palm Coast Park District (92 percent as of December 31, 2016). As of December 31, 2017 , ownership levels, our annual assessments related to capital improvement and special assessment bonds for the ALLETE Properties projects within these districts are $1.4 million for Town Center at Palm Coast and $2.0 million for Palm Coast Park. As we sell property at these projects, the obligation to pay special assessments will pass to the new landowners. In accordance with accounting guidance, these bonds are not reflected as debt on our Consolidated Balance Sheet.

Legal Proceedings.

We are involved in litigation arising in the normal course of business. Also in the normal course of business, we are involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, and compliance with regulations, rate base and cost of service issues, among other things. We do not expect the outcome of these matters to have a material effect on our financial position, results of operations or cash flows.

NOTE 12. COMMON STOCK AND EARNINGS PER SHARE

Summary of Common Stock	**Shares Thousands**	**Equity Millions**
Balance as of December 31, 2014	45,929	$1,107.6
Employee Stock Purchase Plan	18	0.9
Invest Direct	383	19.0
Options and Stock Awards	43	8.6
Equity Issuance Program	1,289	69.9
Forward Sale Agreement and Issuance	1,413	65.4
Balance as of December 31, 2015	49,075	1,271.4
Employee Stock Purchase Plan	16	0.9
Invest Direct	344	20.0
Options and Stock Awards	65	3.7
Contributions to RSOP	60	3.3
Equity Issuance Program	130	8.0
Received for Sale of Land Inventory	(130)	(8.0)
Acquisition of Non-Controlling Interest	—	(4.0)
Balance as of December 31, 2016	49,560	1,295.3
Employee Stock Purchase Plan	12	0.8
Invest Direct	257	19.0
Options and Stock Awards	22	3.6
Contributions to RSOP	50	3.5
Equity Issuance Program	1,000	65.7
Contributions to Pension	216	13.5
Balance as of December 31, 2017	51,117	$1,401.4

NOTE 12. COMMON STOCK AND EARNINGS PER SHARE (Continued)

Equity Issuance Program. We entered into a distribution agreement with Lampert Capital Markets, Inc., in 2008, as amended most recently in August 2016 , with respect to the issuance and sale of up to an aggregate of 13.6 million shares of our common stock, without par value, of which 2.9 million shares remain available for issuance as of December 31, 2017 . For the year ended December 31, 2017 , 1.0 million shares of common stock were issued under this agreement, resulting in net proceeds of $65.7 million (0.1 million shares for net proceeds of $8.0 million in 2016 ; 1.3 million shares for net proceeds of $69.9 million in 2015). The shares issued in 2017 and 2016 were offered and sold pursuant to Registration Statement No. 333-212794, pursuant to which the remaining shares will continue to be offered for sale, from time to time. The shares issued in 2015 were offered and sold pursuant to Registration Statement No. 333-190335.

Earnings Per Share. We compute basic earnings per share using the weighted average number of shares of common stock outstanding during each period. The difference between basic and diluted earnings per share, if any, arises from outstanding stock options, non-vested restricted stock units, performance share awards granted under our Executive Long-Term Incentive Compensation Plan and common shares under the forward sale agreement (described below). No options to purchase shares of common stock were excluded from the computation of diluted earnings per share in 2017 , 2016 and 2015 .

Forward Sale Agreement and Issuance of Common Stock . In 2014, ALLETE entered into a confirmation of forward sale agreement (Agreement) with a forward counterparty in connection with a public offering of 2.8 million shares of ALLETE common stock.

Pursuant to the Agreement, the forward counterparty (or its affiliate) borrowed 2.8 million shares of ALLETE common stock from third parties and sold them to the underwriters. The forward sale price was $48.01 per share, subject to adjustment as provided in the Agreement. In 2014, ALLETE physically settled a portion of its obligations under the Agreement by delivering approximately 1.4 million shares of common stock in exchange for cash proceeds of $65.0 million , and in February 2015, ALLETE physically settled the remaining portion of its obligation under the Agreement by delivering approximately 1.4 million shares of common stock for cash proceeds of $65.4 million .

Contributions to Pension. For the year ended December 31, 2017 , we contributed approximately 0.2 million shares of ALLETE common stock to our pension plan, which had an aggregate value of $13.5 million when contributed (none in 2016 and in 2015). These shares of ALLETE common stock were contributed in reliance upon an exemption available pursuant to Section 4(a)(2) of the Securities Act of 1933, as amended.

Reconciliation of Basic and Diluted Earnings Per Share			
Year Ended December 31	**Basic**	**Dilutive Securities**	**Diluted**
Millions Except Per Share Amounts			
2017			
Net Income Attributable to ALLETE	$172.2		$172.2
Average Common Shares	50.8	0.2	51.0
Earnings Per Share	$3.39		$3.38
2016			
Net Income Attributable to ALLETE	$155.3		$155.3
Average Common Shares	49.3	0.2	49.5
Earnings Per Share	$3.15		$3.14
2015			
Net Income Attributable to ALLETE	$141.1		$141.1
Average Common Shares	48.3	0.1	48.4
Earnings Per Share	$2.92		$2.92

NOTE 13. INCOME TAX EXPENSE

Income Tax Expense

Year Ended December 31	2017	2016	2015
Millions			
Current Income Tax Expense *(a)*			
Federal	—	—	—
State	$0.3	$0.4	$0.2
Total Current Income Tax Expense	$0.3	$0.4	$0.2
Deferred Income Tax Expense			
Federal	$12.1	$12.0	$19.4
Federal – Remeasurement of Deferred Income Taxes *(b)*	(13.0)	—	—
State	15.8	8.1	6.5
Investment Tax Credit Amortization	(0.5)	(0.7)	(0.8)
Total Deferred Income Tax Expense	$14.4	$19.4	$25.1
Total Income Tax Expense	$14.7	$19.8	$25.3

(a) For the years ended December 31, 2017 , 2016 and 2015 , the federal and state current tax expense was minimal due to NOLs which resulted from the bonus depreciation provisions of the Protecting Americans from Tax Hikes Act of 2015, the Tax Increase Prevention Act of 2014 and the American Taxpayer Relief Act of 2012. The federal and state NOLs will be carried forward to offset future taxable income.

(b) Deferred income tax benefit from the remeasurement of deferred income tax assets and liabilities resulting from the TCJA. (See Note 1. Operations and Significant Accounting Policies.)

Reconciliation of Taxes from Federal Statutory Rate to Total Income Tax Expense

Year Ended December 31	2017	2016	2015
Millions			
Income Before Non-Controlling Interest and Income Taxes	$186.9	$175.6	$166.8
Statutory Federal Income Tax Rate	35%	35%	35%
Income Taxes Computed at 35 percent Statutory Federal Rate	$65.4	$61.5	$58.4
Increase (Decrease) in Tax Due to:			
State Income Taxes – Net of Federal Income Tax Benefit	10.5	5.6	4.4
Regulatory Differences for Utility Plant	—	(0.1)	(0.6)
Production Tax Credits	(45.1)	(41.5)	(37.0)
Change in Fair Value of Contingent Consideration	—	(3.8)	—
Remeasurement of Deferred Income Taxes *(a)*	(13.0)	—	—
Other	(3.1)	(1.9)	0.1
Total Income Tax Expense	$14.7	$19.8	$25.3

(a) Deferred income tax benefit from the remeasurement of deferred income tax assets and liabilities resulting from the TCJA. (See Note 1. Operations and Significant Accounting Policies.)

The effective tax rate was 7.9 percent for 2017 (11.3 percent for 2016 ; 15.2 percent for 2015). The 2017 effective tax rate was primarily impacted by production tax credits and the remeasurement of deferred income tax assets and liabilities resulting from the TCJA. (See Note 1. Operations and Significant Accounting Policies.) The 2016 and 2015 effective rates were primarily impacted by production tax credits.

NOTE 13. INCOME TAX EXPENSE (Continued)

Deferred Income Tax Assets and Liabilities

As of December 31	2017	2016
Millions		
Deferred Income Tax Assets		
Employee Benefits and Compensation	$65.9	$104.6
Property Related	104.3	110.5
NOL Carryforwards	99.1	185.6
Tax Credit Carryforwards	294.3	227.4
Power Sales Agreements	35.0	59.3
Regulatory Liabilities	117.7	7.3
Other	33.3	46.9
Gross Deferred Income Tax Assets	749.6	741.6
Deferred Income Tax Asset Valuation Allowance	(60.0)	(43.0)
Total Deferred Income Tax Assets	$689.6	$698.6
Deferred Income Tax Liabilities		
Property Related	$758.3	$1,039.6
Regulatory Asset for Benefit Obligations	61.4	91.9
Unamortized Investment Tax Credits	32.8	33.3
Partnership Basis Differences	34.9	50.9
Regulatory Assets	32.0	25.6
Other	0.7	11.9
Total Deferred Income Tax Liabilities	$920.1	$1,253.2
Net Deferred Income Taxes *(a)*	$230.5	$554.6

(a) Recorded as a net long-term Deferred Income Tax liability on the Consolidated Balance Sheet. Additionally, see Note 1. Operations and Significant Accounting Policies – Revision of Prior Balance Sheet.

NOL and Tax Credit Carryforwards

As of December 31	2017	2016
Millions		
Federal NOL Carryforwards *(a)*	$375.2	$485.3
Federal Tax Credit Carryforwards	$209.2	$163.7
State NOL Carryforwards *(a)*	$289.9	$294.4
State Tax Credit Carryforwards *(b)*	$25.6	$21.0

(a) Pre-tax amounts.
(b) Net of a $59.5 million valuation allowance as of December 31, 2017 ($42.7 million as of December 31, 2016).

The federal NOL and tax credit carryforward periods expire between 2030 and 2037. We expect to fully utilize the federal NOL and federal tax credit carryforwards; therefore, no federal valuation allowance has been recognized as of December 31, 2017 . The state NOL and tax credit carryforward periods expire between 2024 and 2045. We have established a valuation allowance against certain state NOL and tax credits that we do not expect to utilize before their expiration. We do not expect a material impact on the Company's ability to utilize its federal and state NOL and tax credit carryforwards due to the TCJA.

NOTE 13. INCOME TAX EXPENSE (Continued)

Gross Unrecognized Income Tax Benefits	2017	2016	2015
Millions			
Balance at January 1	$2.0	$2.4	$2.0
Additions for Tax Positions Related to the Current Year	0.1	0.1	0.5
Additions for Tax Positions Related to Prior Years	0.1	0.2	0.7
Reductions for Tax Positions Related to Prior Years	(0.1)	(0.3)	(0.7)
Lapse of Statute	(0.4)	(0.4)	(0.1)
Balance as of December 31	$1.7	$2.0	$2.4

Unrecognized tax benefits are the differences between a tax position taken or expected to be taken in a tax return and the benefit recognized and measured pursuant to the "more-likely-than-not" criteria. The unrecognized tax benefit balance includes permanent tax positions which, if recognized would affect the annual effective income tax rate. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The gross unrecognized tax benefits as of December 31, 2017 , included $0.8 million of net unrecognized tax benefits which, if recognized, would affect the annual effective income tax rate.

As of December 31, 2017 , we had no accrued interest (none as of December 31, 2016 , and 2015) related to unrecognized tax benefits included on the Consolidated Balance Sheet due to our NOL carryforwards. We classify interest related to unrecognized tax benefits as interest expense and tax-related penalties in operating expenses on the Consolidated Statement of Income. Interest expense related to unrecognized tax benefits on the Consolidated Statement of Income was immaterial in 2017 (immaterial in 2016 , and in 2015). There were no penalties recognized in 2017 , 2016 or 2015 . The unrecognized tax benefit amounts have been presented as reductions to the tax benefits associated with NOL and tax credit carryforwards on the Consolidated Balance Sheet.

No material changes to unrecognized tax benefits are expected during the next 12 months.

ALLETE and its subsidiaries file a consolidated federal income tax return as well as combined and separate state income tax returns in various jurisdictions. ALLETE has no open federal or state audits, and is no longer subject to federal examination for years before 2013 or state examination for years before 2012.

NOTE 14. RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Changes in Accumulated Other Comprehensive Loss. Comprehensive income (loss) is the change in shareholders' equity during a period from transactions and events from non-owner sources, including net income. The amounts recorded to accumulated other comprehensive loss include unrealized gains and losses on available-for-sale securities, defined benefit pension and other postretirement items, consisting of deferred actuarial gains or losses and prior service costs or credits, and gains and losses on derivatives accounted for as cash flow hedges.

NOTE 14. RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS) (Continued)

Changes in accumulated other comprehensive loss, net of tax, for the years ended December 31, 2017 , 2016 and 2015 , were as follows:

	Unrealized Gain (Loss) on Available-for-sale Securities	Defined Benefit Pension, Other Postretirement Items *(a)*	Gain (Loss) on Cash Flow Hedge	Total
Millions				
Balance as of December 31, 2014	$(0.3)	$(20.7)	$(0.1)	$(21.1)
Other Comprehensive Income (Loss) Before Reclassifications	(0.4)	(4.3)	0.1	(4.6)
Amounts Reclassified From Accumulated Other Comprehensive Loss	(0.1)	1.3	—	1.2
Net Other Comprehensive Income (Loss)	(0.5)	(3.0)	0.1	(3.4)
Balance as of December 31, 2015	(0.8)	(23.7)	—	(24.5)
Other Comprehensive Income (Loss) Before Reclassifications	—	(4.1)	—	(4.1)
Amounts Reclassified From Accumulated Other Comprehensive Loss	(0.2)	0.6	—	0.4
Net Other Comprehensive Income (Loss)	(0.2)	(3.5)	—	(3.7)
Balance as of December 31, 2016	(1.0)	(27.2)	—	(28.2)
Other Comprehensive Income (Loss) Before Reclassifications	1.1	3.9	—	5.0
Amounts Reclassified From Accumulated Other Comprehensive Loss	(0.2)	0.8	—	0.6
Net Other Comprehensive Income (Loss)	0.9	4.7	—	5.6
Balance as of December 31, 2017	$(0.1)	$(22.5)	—	$(22.6)

(a) Defined benefit pension and other postretirement items excluded from our Regulated Operations are recognized in accumulated other comprehensive loss and are subsequently reclassified out of accumulated other comprehensive loss as components of net periodic pension and other postretirement benefit expense. (See Note 15. Pension and Other Postretirement Benefit Plans.)

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

We have noncontributory union, non-union and combined retiree defined benefit pension plans covering eligible employees. The combined retiree defined benefit pension plan was created in 2016, to include all union and non-union retirees from the existing plans as of January 1, 2016. The plans provide defined benefits based on years of service and final average pay. We contributed $1.7 million in cash to the plans in 2017 ($6.3 million in 2016 ; none in 2015). We also contributed approximately 0.2 million shares of ALLETE common stock to the plans in 2017 , which had an aggregate value of $13.5 million when contributed (none in 2016; none in 2015). We also have a defined contribution RSOP covering substantially all employees. The 2017 plan year employer contributions, which are made through the employee stock ownership plan portion of the RSOP, totaled $11.0 million ($9.2 million for the 2016 plan year; $9.0 million for the 2015 plan year). (See Note 12. Common Stock and Earnings Per Share and Note 16. Employee Stock and Incentive Plans.)

The non-union defined benefit pension plan does not allow further crediting of service to the plan and is closed to new participants. The Minnesota Power union defined benefit pension plan is also closed to new participants.

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

We have postretirement health care and life insurance plans covering eligible employees. In 2010, our postretirement health plan was amended to close the plan to employees hired after January 31, 2011. The full eligibility requirement was also amended in 2010, to require employees to be at least age 55 with 10 years of participation in the plan. In 2014, our postretirement life plan was amended to close the plan to non-union employees retiring after December 31, 2015. The postretirement health and life plans are contributory with participant contributions adjusted annually. Postretirement health and life benefits are funded through a combination of Voluntary Employee Benefit Association trusts (VEBAs), established under section 501(c)(9) of the Internal Revenue Code, and irrevocable grantor trusts. In 2017 , no contributions were made to the VEBAs (none in 2016 ; none in 2015) and no contributions were made to the grantor trusts (none in 2016 ; none in 2015).

Management considers various factors when making funding decisions such as regulatory requirements, actuarially determined minimum contribution requirements and contributions required to avoid benefit restrictions for the pension plans. Contributions are based on estimates and assumptions which are subject to change. On January 8, 2018 , we contributed $15.0 million in cash to the defined benefit pension plans. We do not expect to make any additional contributions to the defined benefit pension plans in 2018 , and we do not expect to make any contributions to the defined benefit postretirement health and life plans in 2018 .

Accounting for defined benefit pension and other postretirement benefit plans requires that employers recognize on a prospective basis the funded status of their defined benefit pension and other postretirement plans on their balance sheet and recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost.

The defined benefit pension and postretirement health and life benefit expense (credit) recognized annually by our regulated utilities are expected to be recovered (refunded) through rates filed with our regulatory jurisdictions. As a result, these amounts that are required to otherwise be recognized in accumulated other comprehensive income have been recognized as a long-term regulatory asset (regulatory liability) on the Consolidated Balance Sheet, in accordance with the accounting standards for the effect of certain types of regulation applicable to our Regulated Operations. The defined benefit pension and postretirement health and life benefit expense (credits) associated with our other operations are recognized in accumulated other comprehensive income.

Pension Obligation and Funded Status

As of December 31	**2017**	**2016**
Millions		
Accumulated Benefit Obligation	$745.4	$698.8
Change in Benefit Obligation		
Obligation, Beginning of Year	$743.3	$709.8
Service Cost	10.2	8.1
Interest Cost	32.5	33.2
Actuarial Loss	44.8	12.4
Benefits Paid	(51.0)	(44.5)
Participant Contributions	13.4	24.3
Obligation, End of Year	$793.2	$743.3
Change in Plan Assets		
Fair Value, Beginning of Year	$557.5	$521.3
Actual Return on Plan Assets	91.6	48.8
Employer Contribution *(a)*	30.1	31.9
Benefits Paid	(51.0)	(44.5)
Fair Value, End of Year	$628.2	$557.5
Funded Status, End of Year	$(165.0)	$(185.8)
Net Pension Amounts Recognized in Consolidated Balance Sheet Consist of:		
Current Liabilities	$(1.4)	$(1.4)
Non-Current Liabilities	$(163.6)	$(184.4)

(a) Includes Participant Contributions noted above.

The pension costs that are reported as a component within the Consolidated Balance Sheet, reflected in long-term regulatory assets or liabilities and accumulated other comprehensive income, consist of a net loss of $236.2 million as of December 31, 2017 (net loss of $250.4 million as of December 31, 2016).

Reconciliation of Net Pension Amounts Recognized in Consolidated Balance Sheet

As of December 31	2017	2016
Millions		
Net Loss	$(236.2)	$(250.4)
Accumulated Contributions in Excess of Net Periodic Benefit Cost (Prepaid Pension Asset)	71.2	64.6
Total Net Pension Amounts Recognized in Consolidated Balance Sheet	$(165.0)	$(185.8)

Components of Net Periodic Pension Cost

Year Ended December 31	2017	2016	2015
Millions			
Service Cost	$10.2	$8.1	$10.1
Interest Cost	32.5	33.2	29.9
Expected Return on Plan Assets	(42.4)	(43.6)	(40.7)
Amortization of Loss	9.9	9.5	17.9
Amortization of Prior Service Cost	—	—	0.2
Net Pension Cost	$10.2	$7.2	$17.4

Other Changes in Pension Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income and Regulatory Assets or Liabilities

Year Ended December 31	2017	2016
Millions		
Net (Gain) Loss	$(4.3)	$7.2
Amortization of Loss	(9.9)	(9.5)
Total Recognized in Other Comprehensive Income and Regulatory Assets or Liabilities	$(14.2)	$(2.3)

Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets

As of December 31	2017	2016
Millions		
Projected Benefit Obligation	$793.2	$743.3
Accumulated Benefit Obligation	$745.4	$698.8
Fair Value of Plan Assets	$628.2	$557.5

Postretirement Health and Life Obligation and Funded Status

As of December 31	2017	2016
Millions		
Change in Benefit Obligation		
Obligation, Beginning of Year	$173.4	$160.2
Service Cost	4.4	3.9
Interest Cost	7.7	7.4
Actuarial Loss	15.5	11.9
Benefits Paid	(12.2)	(13.1)
Participant Contributions	3.1	3.1
Plan Amendments	(1.8)	—
Obligation, End of Year	$190.1	$173.4
Change in Plan Assets		
Fair Value, Beginning of Year	$154.3	$153.4
Actual Return on Plan Assets	24.5	9.6
Employer Contribution	1.3	1.3
Participant Contributions	3.1	3.1
Benefits Paid	(12.2)	(13.1)
Fair Value, End of Year	$171.0	$154.3
Funded Status, End of Year	$(19.1)	$(19.1)

Net Postretirement Health and Life Amounts Recognized in Consolidated Balance Sheet Consist of:		
Non-Current Assets	$3.0	$1.4
Current Liabilities	$(1.1)	$(1.1)
Non-Current Liabilities	$(21.0)	$(19.4)

According to the accounting standards for retirement benefits, only assets in the VEBAs are treated as plan assets in the preceding table for the purpose of determining funded status. In addition to the postretirement health and life assets reported in the previous table, we had $19.2 million in irrevocable grantor trusts included in Other Investments on the Consolidated Balance Sheet as of December 31, 2017 ($17.6 million as of December 31, 2016).

The postretirement health and life costs that are reported as a component within the Consolidated Balance Sheet, reflected in regulatory long-term assets or liabilities and accumulated other comprehensive income, consist of the following:

Unrecognized Postretirement Health and Life Costs

As of December 31	2017	2016
Millions		
Net Loss	$21.1	$19.8
Prior Service Credit	(4.6)	(4.7)
Total Unrecognized Postretirement Health and Life Cost	$16.5	$15.1

Reconciliation of Net Postretirement Health and Life Amounts Recognized in Consolidated Balance Sheet

As of December 31	2017	2016
Millions		
Net Loss *(a)*	$(21.1)	$(19.8)
Prior Service Credit	4.6	4.7
Accumulated Net Periodic Benefit Cost in Excess of Contributions *(a)*	(2.6)	(4.0)
Total Net Postretirement Health and Life Amounts Recognized in Consolidated Balance Sheet	$(19.1)	$(19.1)

(a) Excludes gains, losses and contributions associated with irrevocable grantor trusts.

Components of Net Periodic Postretirement Health and Life Cost

Year Ended December 31	2017	2016	2015
Millions			
Service Cost	$4.4	$3.9	$4.3
Interest Cost	7.7	7.4	7.2
Expected Return on Plan Assets	(10.5)	(11.2)	(10.9)
Amortization of Loss	0.3	0.2	0.4
Amortization of Prior Service Credit	(2.0)	(2.9)	(3.0)
Net Postretirement Health and Life Credit	$(0.1)	$(2.6)	$(2.0)

Other Changes in Postretirement Benefit Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income and Regulatory Assets or Liabilities

Year Ended December 31	2017	2016
Millions		
Net Loss	$1.6	$13.5
Prior Service Credit Arising During the Period	(1.8)	—
Amortization of Prior Service Credit	2.0	2.9
Amortization of Loss	(0.3)	(0.2)
Total Recognized in Other Comprehensive Income and Regulatory Assets or Liabilities	$1.5	$16.2

Estimated Future Benefit Payments	Pension	Postretirement Health and Life
Millions		
2018	$46.3	$9.2
2019	$46.2	$9.5
2020	$45.9	$9.6
2021	$45.8	$9.6
2022	$45.8	$9.6
Years 2023 – 2027	$228.0	$49.7

The pension and postretirement health and life costs recorded in regulatory long-term assets or liabilities and accumulated other comprehensive income expected to be recognized as a component of net pension and postretirement benefit costs for the year ending December 31, 2018 , are as follows:

	Pension	Postretirement Health and Life
Millions		
Net Loss	$12.0	$0.7
Prior Service Credit	—	(1.8)
Total Pension and Postretirement Health and Life Cost (Credit)	$12.0	$(1.1)

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Assumptions Used to Determine Benefit Obligation

As of December 31	2017	2016
Discount Rate		
Pension	3.81 - 3.96%	4.53%
Postretirement Health and Life	3.86%	4.57%
Rate of Compensation Increase	3.70 - 4.10%	3.70 - 4.30%
Health Care Trend Rates		
Trend Rate	5.00 - 6.73%	5.00 - 7.00%
Ultimate Trend Rate	4.50%	4.50%
Year Ultimate Trend Rate Effective	2038	2038

Assumptions Used to Determine Net Periodic Benefit Costs

Year Ended December 31	2017	2016	2015
Discount Rate	4.53 - 4.57%	4.72 - 4.73%	4.30 - 4.33%
Expected Long-Term Return on Plan Assets			
Pension	7.50%	8.00%	8.00%
Postretirement Health and Life	6.00 - 7.50%	6.40 - 8.00%	6.40 - 8.00%
Rate of Compensation Increase	3.70 - 4.30%	3.70 - 4.30%	3.70 - 4.30%

In establishing the expected long-term rate of return on plan assets, we determine the long-term historical performance of each asset class, adjust these for current economic conditions, and utilizing the target allocation of our plan assets, forecast the expected long-term rate of return.

The discount rate is computed using a bond matching study which utilizes a portfolio of high quality bonds that produce cash flows similar to the projected costs of our pension and other postretirement plans.

The Company utilizes actuarial assumptions about mortality to calculate the pension and postretirement health and life benefit obligations. The mortality assumptions used to calculate our pension and other postretirement benefit obligations as of December 31, 2017 , considered a modified RP-2014 mortality table and mortality projection scale.

Sensitivity of a One Percent Change in Health Care Trend Rates

	One Percent Increase	One Percent Decrease
Millions		
Effect on Total of Postretirement Health and Life Service and Interest Cost	$1.9	($1.5)
Effect on Postretirement Health and Life Obligation	$23.4	($19.3)

Actual Plan Asset Allocations

	Pension		Postretirement Health and Life *(a)*	
	2017	2016	2017	2016
Equity Securities	53%	49%	64%	60%
Debt Securities	38%	39%	31%	34%
Private Equity	5%	7%	5%	6%
Real Estate	4%	5%	—	—
	100%	100%	100%	100%

(a) Includes VEBAs and irrevocable grantor trusts.

There were no shares of ALLETE common stock included in pension plan equity securities as of December 31, 2017 (no shares as of December 31, 2016).

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

The defined benefit pension plans have adopted a dynamic asset allocation strategy (glide path) that increases the invested allocation to fixed income assets as the funding level of the plan increases to better match the sensitivity of the plan's assets and liabilities to changes in interest rates. This is expected to reduce the volatility of reported pension plan expenses. The postretirement health and life plans' assets are diversified to achieve strong returns within managed risk. Equity securities are diversified among domestic companies with large, mid and small market capitalizations, as well as investments in international companies. The majority of debt securities are made up of investment grade bonds.

Following are the current targeted allocations as of December 31, 2017 :

Plan Asset Target Allocations	**Pension**	**Postretirement Health and Life** *(a)*
Equity Securities	56%	60%
Debt Securities	35%	37%
Real Estate	9%	3%
	100%	100%

(a) Includes VEBAs and irrevocable grantor trusts.

Fair Value

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. These inputs, which are used to measure fair value, are prioritized through the fair value hierarchy. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. This category includes various U.S. equity securities, public mutual funds, and futures. These instruments are valued using the closing price from the applicable exchange or whose value is quoted and readily traded daily.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs. This category includes various bonds and non-public funds whose underlying investments may be Level 1 or Level 2 securities.

Level 3 — Significant inputs that are generally less observable from objective sources. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value. This category includes private equity funds and real estate valued through external appraisal processes. Valuation methodologies incorporate pricing models, discounted cash flow models, and similar techniques which utilize capitalization rates, discount rates, cash flows and other factors.

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)
Fair Value (Continued)

Pension Fair Value

	Fair Value as of December 31, 2017			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	—	$108.6	—	$108.6
U.S. Mid-cap Growth *(a)*	—	51.9	—	51.9
U.S. Small-cap *(a)*	—	51.5	—	51.5
International	—	122.3	—	122.3
Debt Securities:				
Fixed Income	—	222.8	—	222.8
Cash and Cash Equivalents	$12.4	—	—	12.4
Private Equity Funds	—	—	$33.2	33.2
Real Estate	—	—	25.5	25.5
Total Fair Value of Assets	$12.4	$557.1	$58.7	$628.2

(a) The underlying investments consist of actively-managed funds managed to achieve the returns of certain U.S. equity securities large-cap, mid-cap and small-cap indexes.

Recurring Fair Value Measures

Activity in Level 3	**Private Equity Funds**	**Real Estate**
Millions		
Balance as of December 31, 2016	$40.6	$25.6
Actual Return on Plan Assets	7.1	1.7
Purchases, Sales, and Settlements – Net	(14.5)	(1.8)
Balance as of December 31, 2017	$33.2	$25.5

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)
Fair Value (Continued)

	Fair Value as of December 31, 2016			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	$94.6	—	—	$94.6
U.S. Mid-cap Growth *(a)*	—	$44.8	—	44.8
U.S. Small-cap *(a)*	—	45.0	—	45.0
International	46.7	42.3	—	89.0
Debt Securities:				
Fixed Income	—	200.1	—	200.1
Cash and Cash Equivalents	17.8	—	—	17.8
Private Equity Funds	—	—	$40.6	40.6
Real Estate	—	—	25.6	25.6
Total Fair Value of Assets	$159.1	$332.2	$66.2	$557.5

(a) The underlying investments classified under U.S. Equity Securities consist of money market funds (Level 1), mutual funds (Level 1) and actively-managed funds (Level 2), which are combined with futures, and settle daily, to achieve the returns of the U.S. Equity Securities Mid-cap Growth and Small-cap funds. Our exposure with respect to these investments includes both the futures and the underlying investments.

Recurring Fair Value Measures

Activity in Level 3	**Private Equity Funds**	**Real Estate**
Millions		
Balance as of December 31, 2015	$43.3	$28.9
Actual Return on Plan Assets	5.0	2.3
Purchases, Sales, and Settlements – Net	(7.7)	(5.6)
Balance as of December 31, 2016	$40.6	$25.6

Postretirement Health and Life Fair Value

	Fair Value as of December 31, 2017			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities: *(a)*				
U.S. Large-cap	$32.1	—	—	$32.1
U.S. Mid-cap Growth	24.3	—	—	24.3
U.S. Small-cap	15.5	—	—	15.5
International	35.8	—	—	35.8
Debt Securities:				
Mutual Funds	49.8	—	—	49.8
Fixed Income	—	$4.5	—	4.5
Cash and Cash Equivalents	0.8	—	—	0.8
Private Equity Funds	—	—	$8.2	8.2
Total Fair Value of Assets	$158.3	$4.5	$8.2	$171.0

(a) The underlying investments consist of mutual funds (Level 1).

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)
Fair Value (Continued)

Recurring Fair Value Measures

Activity in Level 3	Private Equity Funds
Millions	
Balance as of December 31, 2016	$9.5
Actual Return on Plan Assets	2.6
Purchases, Sales, and Settlements – Net	(3.9)
Balance as of December 31, 2017	$8.2

	Fair Value as of December 31, 2016			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities: *(a)*				
U.S. Large-cap	$27.9	—	—	$27.9
U.S. Mid-cap Growth	20.7	—	—	20.7
U.S. Small-cap	14.0	—	—	14.0
International	27.9	—	—	27.9
Debt Securities:				
Mutual Funds	48.6	—	—	48.6
Fixed Income	—	$4.6	—	4.6
Cash and Cash Equivalents	1.1	—	—	1.1
Private Equity Funds	—	—	$9.5	9.5
Total Fair Value of Assets	$140.2	$4.6	$9.5	$154.3

(a) The underlying investments consist of mutual funds (Level 1).

Recurring Fair Value Measures

Activity in Level 3	Private Equity Funds
Millions	
Balance as of December 31, 2015	$12.0
Actual Return on Plan Assets	1.4
Purchases, Sales, and Settlements – Net	(3.9)
Balance as of December 31, 2016	$9.5

Accounting and disclosure requirements for the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act) provide guidance for employers that sponsor postretirement health care plans that provide prescription drug benefits. We provide a fully insured postretirement health benefit, including a prescription drug benefit, which qualifies us for a federal subsidy under the Act. The federal subsidy is reflected in the premiums charged to us by the insurance company.

NOTE 16. EMPLOYEE STOCK AND INCENTIVE PLANS

Employee Stock Ownership Plan. We sponsor an ESOP within the RSOP. Eligible employees may contribute to the RSOP plan as of their date of hire. In 1990, the ESOP issued a $75.0 million note to use as consideration for 2.8 million shares (1.9 million shares adjusted for stock splits) of our common stock. The note matured in December 2015. The ESOP shares were initially pledged as collateral for the debt. As the debt was repaid, shares were released from collateral and allocated to participants based on the proportion of debt service paid in the year. As shares were released from collateral, we reported compensation expense equal to the current market price of the shares less dividends on allocated shares. The dividends received by the ESOP are distributed to participants. Dividends on allocated ESOP shares are recorded as a reduction of retained earnings. Future ESOP employer allocations will be funded with contributions paid in either cash or the issuance of ALLETE common stock at the Company's discretion. ESOP compensation expense was $11.0 million in 2017 ($9.2 million in 2016 ; $9.0 million in 2015).

According to the accounting standards for stock compensation, unallocated shares of ALLETE common stock held and purchased by the ESOP were treated as unearned ESOP shares and not considered outstanding for earnings per share computations. ESOP shares are included in earnings per share computations after they are allocated to participants.

As of December 31	2017	2016	2015
Millions			
ESOP Shares			
Allocated	1.4	1.6	1.8
Unallocated	—	—	—
Total	1.4	1.6	1.8
Fair Value of Unallocated Shares	—	—	—

Stock-Based Compensation. *Stock Incentive Plan.* Under our Executive Long-Term Incentive Compensation Plan (Executive Plan), share-based awards may be issued to key employees through a broad range of methods, including non-qualified and incentive stock options, performance shares, performance units, restricted stock, restricted stock units, stock appreciation rights and other awards. There are 1.0 million shares of ALLETE common stock reserved for issuance under the Executive Plan, of which 0.8 million of these shares remain available for issuance as of December 31, 2017 .

The following types of share-based awards were outstanding in 2017, 2016 or 2015:

Non-Qualified Stock Options . These options allow for the purchase of shares of common stock at a price equal to the market value of our common stock at the date of grant. Options become exercisable beginning one year after the grant date, with one-third vesting each year over three years. Options may be exercised up to ten years following the date of grant. In the case of qualified retirement, death or disability, options vest immediately and the period over which the options can be exercised is three years. Employees have up to three months to exercise vested options upon voluntary termination or involuntary termination without cause. All options are canceled upon termination for cause. All options vest immediately upon retirement, death, disability or a change of control, as defined in the award agreement. We determine the fair value of options using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on the straight-line basis over the options' vesting periods, or the accelerated vesting period if the employee is eligible for retirement. Stock options have not been granted since 2008 and none were outstanding as of December 31, 2017 .

The risk-free interest rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the grant date. Expected volatility is estimated based on the historic volatility of our stock and the stock of our peer group companies. We utilize historical option exercise and employee pre-vesting termination data to estimate the option life. The dividend growth rate is based upon historical growth rates in our dividends.

NOTE 16. EMPLOYEE STOCK AND INCENTIVE PLANS (Continued)
Stock-Based Compensation (Continued)

Performance Shares. Under the performance share awards plan, the number of shares earned is contingent upon attaining specific market goals over a three -year performance period. Market goals are measured by total shareholder return relative to a group of peer companies. In the case of qualified retirement, death, or disability during a performance period, a pro rata portion of the award will be earned at the conclusion of the performance period based on the market goals achieved. In the case of termination of employment for any reason other than qualified retirement, death, or disability, no award will be earned. If there is a change in control, a pro rata portion of the award will be paid based on the greater of actual performance up to the date of the change in control or target performance. The fair value of these awards is determined by the probability of meeting the total shareholder return goals. Compensation cost is recognized over the three -year performance period based on our estimate of the number of shares which will be earned by the award recipients.

Restricted Stock Units. Under the restricted stock units plan, shares for participants eligible for retirement vest monthly over a three -year period. For participants not eligible for retirement, shares vest at the end of the three -year period. In the case of qualified retirement, death or disability, a pro rata portion of the award will be earned. In the case of termination of employment for any reason other than qualified retirement, death or disability, no award will be earned. If there is a change in control, a pro rata portion of the award will be earned. The fair value of these awards is equal to the grant date fair value. Compensation cost is recognized over the three -year vesting period based on our estimate of the number of shares which will be earned by the award recipients.

Employee Stock Purchase Plan (ESPP). Under our ESPP, eligible employees may purchase ALLETE common stock at a 5 percent discount from the market price. Because the discount is not greater than 5 percent , we are not required to apply fair value accounting to these awards.

RSOP . The RSOP is a contributory defined contribution plan subject to the provisions of the Employee Retirement Income Security Act of 1974, as amended, and qualifies as an employee stock ownership plan and profit sharing plan. The RSOP provides eligible employees an opportunity to save for retirement.

The following share-based compensation expense amounts were recognized in our Consolidated Statement of Income for the periods presented.

Share-Based Compensation Expense

Year Ended December 31	2017	2016	2015
Millions			
Performance Shares	$2.1	$1.8	$1.8
Restricted Stock Units	1.0	0.8	0.8
Total Share-Based Compensation Expense	$3.1	$2.6	$2.6
Income Tax Benefit	$0.9	$1.1	$1.1

There were no capitalized share-based compensation costs during the years ended December 31, 2017 , 2016 or 2015 .

As of December 31, 2017 , the total unrecognized compensation cost for the performance share awards and restricted stock units not yet recognized in our Consolidated Statement of Income was $2.4 million and $1.0 million , respectively. These amounts are expected to be recognized over a weighted-average period of 1.7 years .

NOTE 16. EMPLOYEE STOCK AND INCENTIVE PLANS (Continued)
Stock-Based Compensation (Continued)

Non-Qualified Stock Options. The following table presents information regarding our outstanding stock options.

	2017		2016		2015	
	Number of Options	Weighted-Average Exercise Price	Number of Options	Weighted-Average Exercise Price	Number of Options	Weighted-Average Exercise Price
Outstanding as of January 1	4,357	$40.29	39,654	$44.39	66,279	$44.39
Exercised	(4,357)	$40.29	(35,297)	$44.89	(24,456)	$44.52
Forfeited	—	—	—	—	(2,169)	$42.93
Outstanding as of December 31	—	—	4,357	$40.29	39,654	$44.39
Exercisable as of December 31	—	—	4,357	$40.29	39,654	$44.39

Cash received from non-qualified stock options exercised was $0.3 million in 2017 . The intrinsic value of a stock award is the amount by which the fair value of the underlying stock exceeds the exercise price of the award. The total intrinsic value of options exercised was $0.1 million during 2017 ($0.5 million in 2016 ; $0.2 million in 2015).

Performance Shares. The following table presents information regarding our non-vested performance shares.

	2017		2016		2015	
	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Non-vested as of January 1	127,580	$52.56	119,540	$52.72	119,635	$48.26
Granted *(a)*	50,729	$62.90	57,189	$52.43	43,583	$58.95
Unearned Grant Award	(40,801)	$46.27	(42,126)	$52.70	(36,670)	$45.41
Forfeited	(9,610)	$58.29	(7,023)	$53.45	(7,008)	$53.49
Non-vested as of December 31	127,898	$58.23	127,580	$52.56	119,540	$52.72

(a) Shares granted include accrued dividends .

There were 35,894 performance shares granted in January 2018 for the three -year performance period ending in 2020 . The ultimate issuance is contingent upon the attainment of certain goals of ALLETE during the performance periods. The grant date fair value of the performance shares granted was $2.9 million . There were 58,293 performance shares awarded in February 2018 . The grant date fair value of the shares awarded was $3.5 million .

NOTE 16. EMPLOYEE STOCK AND INCENTIVE PLANS (Continued)
Stock-Based Compensation (Continued)

Restricted Stock Units. The following table presents information regarding our available restricted stock units.

	2017		2016		2015	
	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Available as of January 1	54,728	$51.79	57,694	$49.86	53,888	$44.47
Granted *(a)*	21,241	$62.20	20,351	$50.25	26,702	$54.81
Awarded	(17,281)	$49.72	(19,661)	$44.33	(19,464)	$41.44
Forfeited	(3,440)	$56.00	(3,656)	$52.87	(3,432)	$51.52
Available as of December 31	55,248	$56.18	54,728	$51.79	57,694	$49.86

(a) Shares granted include accrued dividends.

There were 14,569 restricted stock units granted in January 2018 for the vesting period ending in 2020 . The grant date fair value of the restricted stock units granted was $1.1 million . There were 12,766 restricted stock units awarded in February 2018 . The grant date fair value of the shares awarded was $0.7 million .

NOTE 17. BUSINESS SEGMENTS

We present three reportable segments: Regulated Operations, ALLETE Clean Energy, and U.S. Water Services. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment.

Regulated Operations includes three operating segments which consist of our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC. ALLETE Clean Energy is our business focused on developing, acquiring and operating clean and renewable energy projects. U.S. Water Services is our integrated water management company. The ALLETE Clean Energy and U.S. Water Services reportable segments comprise our Energy Infrastructure and Related Services businesses. We also present Corporate and Other which includes two operating segments, BNI Energy, our coal mining operations in North Dakota, and ALLETE Properties, our legacy Florida real estate investment, along with other business development and corporate expenditures, unallocated interest expense, a small amount of non-rate base generation, approximately 5,000 acres of land in Minnesota, and earnings on cash and investments.

NOTE 17. BUSINESS SEGMENTS (Continued)

Year Ended December 31	2017	2016	2015
Millions			
Operating Revenue			
Regulated Operations	$1,063.8	$1,000.7	$991.2
Energy Infrastructure and Related Services			
ALLETE Clean Energy *(a)*	80.5	80.5	262.1
U.S. Water Services	151.8	137.5	119.8
Corporate and Other	123.2	121.0	113.3
Total Operating Revenue	$1,419.3	$1,339.7	$1,486.4
Net Income (Loss) Attributable to ALLETE *(b)(c)*			
Regulated Operations	$128.4	$135.5	$131.6
Energy Infrastructure and Related Services			
ALLETE Clean Energy	41.5	13.4	29.9
U.S. Water Services	10.7	1.5	0.9
Corporate and Other	(8.4)	4.9	(21.3)
Total Net Income Attributable to ALLETE	$172.2	$155.3	$141.1
Depreciation and Amortization			
Regulated Operations	$132.6	$154.3	$135.1
Energy Infrastructure and Related Services			
ALLETE Clean Energy	23.4	22.3	18.7
U.S. Water Services	9.8	8.9	7.3
Corporate and Other	11.7	10.3	8.9
Total Depreciation and Amortization	$177.5	$195.8	$170.0
Operating Expenses – Other *(d)*			
ALLETE Clean Energy	—	$3.3	—
Corporate and Other	$(0.7)	(13.6)	$36.3
Total Operating Expenses – Other	$(0.7)	$(10.3)	$36.3
Interest Expense *(c)*			
Regulated Operations	$57.0	$52.1	$53.9
Energy Infrastructure and Related Services			
ALLETE Clean Energy	4.2	5.8	3.3
U.S. Water Services	1.6	1.7	1.4
Corporate and Other	10.3	14.5	8.6
Eliminations	(5.3)	(3.8)	(2.3)
Total Interest Expense	$67.8	$70.3	$64.9
Equity Earnings in ATC			
Regulated Operations	$22.5	$18.5	$16.3

(a) Includes the construction and sale of a wind energy facility by ALLETE Clean Energy to Montana-Dakota Utilities for $197.7 million in 2015.

(b) Net income in 2017 included a favorable impact of $13.0 million after-tax due to the remeasurement of deferred income tax assets and liabilities resulting from the TCJA, which consisted of a $23.6 million after-tax benefit for ALLETE Clean Energy, a $9.2 million after-tax benefit for U.S. Water Services and a $19.8 million after-tax expense for Corporate and Other. The TCJA did not have an impact on net income for our Regulated Operations as the remeasurement of deferred income tax assets and liabilities primarily resulted in the recording of regulatory assets and liabilities. (See Note 1. Operations and Significant Accounting Policies, and Note 4. Regulatory Matters.)

(c) Includes interest expense resulting from intercompany loan agreements and allocated to certain subsidiaries. The amounts are eliminated in consolidation.

(d) See Note 1. Operations and Significant Accounting Policies.

NOTE 17. BUSINESS SEGMENTS (Continued)

Year Ended December 31	2017	2016	2015
Millions			
Income Tax Expense (Benefit) *(a)*			
Regulated Operations *(b)*	$27.2	$5.9	$24.4
Energy Infrastructure and Related Services			
ALLETE Clean Energy	(14.2)	8.1	21.0
U.S. Water Services	(7.8)	1.4	0.9
Corporate and Other *(b)*	9.5	4.4	(21.0)
Total Income Tax Expense	$14.7	$19.8	$25.3

(a) Income tax expense in 2017 included an income tax benefit of $13.0 million due to the remeasurement of deferred income tax assets and liabilities resulting from the TCJA, which consisted of income tax benefits of $23.6 million for ALLETE Clean Energy and $9.2 million for U.S. Water Services as well as additional income tax expense of $19.8 million for Corporate and Other. The TCJA did not have an impact on income tax expense for our Regulated Operations as the remeasurement of deferred income tax assets and liabilities primarily resulted in the recording of regulatory assets and liabilities. (See Note 1. Operations and Significant Accounting Policies, and Note 4. Regulatory Matters.)

(b) In 2017, Regulated Operations includes $14.0 million of income tax expense related to North Dakota investment tax credits transferred to Corporate and Other and higher pre-tax income for the favorable impact for the regulatory outcome of the MPUC's modification of its November 2016 order on the allocation of North Dakota investment tax credits. There was no impact to net income for Regulated Operations. Corporate and Other recorded an offsetting income tax benefit of $7.9 million in 2017. In 2016, Regulated Operations includes $15.0 million of income tax benefit for North Dakota investment tax credits transferred from Corporate and Other and lower pre-tax income related to the adverse impact for the regulatory outcome of the November 2016 MPUC order. There was no impact to net income for Regulated Operations. Corporate and Other recorded an offsetting income tax expense of $8.8 million in 2016. (See Note 4. Regulatory Matters.)

As of December 31	2017	2016
Millions		
Assets		
Regulated Operations *(a)*	$3,886.6	$3,823.9
Energy Infrastructure and Related Services		
ALLETE Clean Energy	600.5	566.0
U.S. Water Services	292.4	264.1
Corporate and Other	300.5	222.9
Total Assets *(a)*	$5,080.0	$4,876.9
Capital Expenditures		
Regulated Operations	$177.1	$121.8
Energy Infrastructure and Related Services		
ALLETE Clean Energy	56.1	106.9
U.S. Water Services	4.4	3.7
Corporate and Other	28.9	15.4
Total Capital Expenditures	$266.5	$247.8

(a) See Note 1. Operations and Significant Accounting Policies – Revision of Prior Balance Sheet.

NOTE 18. QUARTERLY FINANCIAL DATA (UNAUDITED)

Information for any one quarterly period is not necessarily indicative of the results which may be expected for the year.

Quarter Ended	Mar. 31	Jun. 30	Sept. 30	Dec. 31
Millions Except Earnings Per Share				
2017				
Operating Revenue	$365.6	$353.3	$362.5	$337.9
Operating Income	$72.6	$55.0	$69.0	$33.2
Net Income Attributable to ALLETE	$49.0	$36.9	$44.9	$41.4
Earnings Per Share of Common Stock				
Basic	$0.97	$0.73	$0.88	$0.81
Diluted	$0.97	$0.72	$0.88	$0.81
2016				
Operating Revenue	$333.8	$314.8	$349.6	$341.5
Operating Income	$66.8	$42.2	$53.4	$61.1
Net Income Attributable to ALLETE	$45.9	$24.8	$40.3	$44.3
Earnings Per Share of Common Stock				
Basic	$0.93	$0.50	$0.82	$0.89
Diluted	$0.93	$0.50	$0.81	$0.89
2015				
Operating Revenue	$320.0	$323.3	$462.5	$380.6
Operating Income	$56.4	$39.5	$85.2	$29.6
Net Income Attributable to ALLETE	$39.9	$22.5	$60.4	$18.3
Earnings Per Share of Common Stock				
Basic	$0.85	$0.46	$1.24	$0.37
Diluted	$0.85	$0.46	$1.23	$0.37

Schedule II

ALLETE

Valuation and Qualifying Accounts and Reserves

	Balance at Beginning of Period	Additions		Deductions from Reserves *(a)*	Balance at End of Period
		Charged to Income	Other Charges		
Millions					
Reserve Deducted from Related Assets					
Reserve For Uncollectible Accounts					
2015 Trade Accounts Receivable	$1.1	$1.6	—	$1.7	$1.0
Finance Receivables – Long-Term	$0.6	—	—	—	$0.6
2016 Trade Accounts Receivable	$1.0	$4.1	—	$2.0	$3.1
Finance Receivables – Long-Term	$0.6	—	—	$0.6	—
2017 Trade Accounts Receivable	$3.1	$0.8	—	$1.8	$2.1
Finance Receivables – Long-Term	—	—	—	—	—
Deferred Asset Valuation Allowance					
2015 Deferred Tax Assets	$22.1	$9.5	—	—	$31.6
2016 Deferred Tax Assets	$31.6	$11.4	—	—	$43.0
2017 Deferred Tax Assets	$43.0	$17.0	—	—	$60.0

(a) Includes uncollectible accounts written-off.

ALLETE

EXECUTIVE LONG-TERM INCENTIVE COMPENSATION PLAN

RESTRICTED STOCK UNIT GRANT

[Effective 2018]

[Eligible Executive Employees]

Name

In accordance with the terms of ALLETE's Executive Long-Term Incentive Compensation Plan, as amended (the "Plan"), and as determined by and through the Executive Compensation Committee of ALLETE's Board of Directors, ALLETE hereby grants to you (the "Participant") Restricted Stock Units ("RSU's") as set forth below, payable in the form of ALLETE Common Stock, subject to the terms and conditions set forth in this Grant, including Annex A hereto, and all documents incorporated herein by reference:

Number of Restricted Stock Units:
Date of Grant:
Vesting Period:

This Grant is made in accordance with the Plan.

Further terms and conditions of the Grant are set forth in Annex A hereto, which is an integral part of this Grant.

Any term, provision or condition applicable to the Restricted Stock Units set forth in the Plan and not set forth herein is hereby incorporated by reference. To the extent any provision hereof is inconsistent with a Plan provision, the Plan provision will govern.

YOU SHOULD CAREFULLY READ AND REVIEW THE TERMS AND CONDITIONS SET FORTH IN THIS GRANT, INCLUDING ANNEX A HERETO, WHICH CONTAINS IMPORTANT INFORMATION, INCLUDING MANDATORY CLAIMS AND ARBITRATION PROCEDURES.

You will be deemed to have accepted this Grant on the Date of Grant, and all its associated terms and conditions, including the mandatory claims and arbitration procedures set forth in Annex A, unless you notify the Company of your non-acceptance of the Grant by contacting the Manager–Compensation and Benefits, in writing within sixty (60) days of the Date of Grant.

IN WITNESS WHEREOF, ALLETE has caused this Grant to be executed by its Chairman, President and Chief Executive Officer as of the date and year first above written.

ALLETE

By: _____

Chairman, President & CEO

Attachment: Annex A

ANNEX A
TO
ALLETE
EXECUTIVE LONG-TERM INCENTIVE COMPENSATION PLAN
RESTRICTED STOCK UNIT GRANT

The grant of restricted stock units (each, a "RSU") under the ALLETE Executive Long-Term Incentive Compensation Plan (the "Plan"), evidenced by the Grant to which this is annexed, is subject to the following additional terms and conditions:

1. Form and Timing of Payment. Subject to the provisions hereof, each RSU will be paid in the form of one share of ALLETE common stock (each, a "Share"), plus accrued Dividend Equivalents. Shares will be deposited into your ALLETE Invest Direct plan account. Except as otherwise provided in sections 3 and 4, below, payment will be made during the period ending sixty days after the end of the vesting period; provided, however, the Participant will not be permitted, directly or indirectly, to designate the taxable year of the distribution. Payment will be subject to withholding Shares equal in value to the minimum amount of tax required to be withheld by law.

2. Dividend Equivalents . You will receive Dividend Equivalents in connection with the RSUs granted. Dividend Equivalents will be calculated and credited to you at the time the underlying RSUs are paid. Dividend Equivalents will be in the form of additional RSUs, which will be added to the number of RSUs subject to the grant, and will equal the number of Shares (including fractional Shares) that could have been purchased on applicable dividend payment dates, based on the closing ALLETE common stock price as reported in the consolidated transaction reporting system on that date, with cash dividends that would have been paid on the underlying RSUs, if such RSUs were Shares. Dividend Equivalents will only become payable if and to the extent the underlying RSUs vest and become payable.

3. Payment Upon Retirement, Death or Disability; Forfeiture Upon Other Termination of Employment, Default on Certain Agreements or Unsatisfactory Job Performance .

3.1 Subject to Section 3.4 below, if during the vesting period you (i) Retire, (ii) die while employed by a Related Company, or (iii) become Disabled, a portion of the unvested RSUs subject to the Grant will vest and be paid to you (or your beneficiary or estate) during the period ending sixty days after such event; provided, however, you will not be permitted, directly or indirectly, to designate the taxable year of the distribution. Except as otherwise provided in Section 4, payment pursuant to this Section 3.1 will be prorated, after giving effect to accumulated Dividend Equivalents, based on the number of whole calendar months within the vesting period that had elapsed as of the date of Retirement, death or Disability in relation to the number of calendar months in the vesting period. For purposes of this calculation, you will be credited with a whole month if you were employed on the 15 th of the month.

3.2 Except as otherwise provided in Section 4, if during the vesting period or prior to payment of all RSUs you have a Separation from Service for any reason other than those specified in Section 3.1 above, all unvested or unpaid RSUs subject to the Grant (and related Dividend Equivalents) will be forfeited on the date of such Separation from Service.

3.3 If during the vesting period or prior to payment of all RSUs you are demoted, you default on any written agreement with a Related Company related to a restrictive employment covenant (such as confidentiality, non-disclosure, non-competition, non-solicitation, or the like), or if ALLETE determines, in its sole discretion, that your job performance is unsatisfactory, ALLETE may cancel or amend your grant relating to any unpaid RSUs, resulting in the forfeiture of some portion or all of your unpaid RSUs (and related Dividend Equivalents).

3.4 Notwithstanding anything herein to the contrary, if you become entitled to a payment of the RSUs by reason of your Retirement and if you are a Specified Employee on the date of such Retirement, payment shall not be made until the earlier of: (i) the expiration of the six-month period beginning on the date of your Retirement, or (ii) the date of your death. The payment to which a Specified Employee would otherwise be entitled during this six-month period shall be paid, together with Dividend Equivalents that have accrued during this six-month delay, during the seventh month following the date of the Participant's Retirement, or, if earlier, the date of the Participant's death.

4. Change in Control . Upon a Change in Control, unless the Committee provides otherwise prior to the Change in Control, outstanding unvested RSUs shall be prorated (as described below) and such prorated RSUs shall immediately vest and be payable to you during the period ending sixty days after the Change in Control. The RSUs will not be subject to proration and immediately vest, however, if and to the extent that the Grant is, in connection with the Change in Control, fully assumed by the successor corporation or parent thereof; in such case, the RSUs shall be prorated and immediately vest upon your termination of employment by the successor corporation for reasons other than cause within 18 months following the Change in Control and be payable to the Participant during the period ending sixty days after the termination of employment. Any payment on account of or in connection with a Change in Control will be prorated, after giving effect to the accumulation of Dividend Equivalents, based on the number of whole calendar months within the three-year vesting period that had elapsed as of the date of the Change in Control or termination of employment, as applicable, in relation to the number of calendar months in the three-year vesting period. For purposes of this calculation, you will be credited with a whole month if you were employed on the 15 th of the month. In no event will you be permitted, directly or indirectly, to designate the taxable year of the distribution on account of or in connection with a Change in Control.

5. Compensation Recovery Policy . The Grant is subject to the terms of any compensation recovery policy or policies established by ALLETE as may be amended from time to time ("Compensation Recovery Policy"). ALLETE hereby incorporates into the Grant the terms of the Compensation Recovery Policy.

6. Section 409A Compliance. This Grant is intended to comply with Section 409A or an exemption thereunder, and, accordingly, to the maximum extent permitted, the Plan and the Grant shall be interpreted and administered in compliance therewith. Notwithstanding any other provision of the Grant, payments provided pursuant to the Grant may only be made upon an event and in a manner that complies with Section 409A or an applicable exemption. Any payments pursuant to the Grant that may be excluded from Section 409A as a short-term deferral shall be excluded from Section 409A to the maximum extent possible. To the extent that any provision of the Grant would cause a conflict with the requirements of Section 409A or would cause the administration of the Grant to fail to satisfy Section 409A, such provision shall be deemed null and void to the extent permitted by applicable law. Nothing herein shall be construed as a guarantee of any particular tax treatment. ALLETE makes no representation that the Grant complies with Section 409A and in no event shall ALLETE be liable for the payment of any taxes and penalties that you may incur under Section 409A.

7. Claims Procedure and Arbitration. The Grant is subject to the following claims procedures:

7.1 Mandatory Claims Procedures. If you or any person acting on your behalf (the "Claimant") has any claim or dispute related in any way to the Grant or to the Plan, the Claimant must follow these claims procedures. All claims must be brought no later than one year following the date on which the claim first arose and any claim not submitted within such time limit will be waived.

7.2 Claim Submission. Any claim must be made in writing to the Claims Administrator. The Claims Administrator, or its delegate, shall notify the Claimant of the resolution of the Claim within 90 days after receipt of the claim; provided, however, if the Claims Administrator determines that an extension is necessary, the 90-day period shall be extended to up to 180 days upon notice to that effect to the Claimant.

7.3 Notice of Denial. If a claim is wholly or partially denied, the denial notice shall contain (i) the reason or reasons for denial of the claim, and (ii) references to the pertinent Plan provisions upon which the denial is based. Unless the claim is submitted for arbitration as provided below and in the Plan, the Claims Administrator's decision or action shall be final, conclusive and binding on all persons having any interest in the Plan.

7.4 Arbitration. If, after exhausting the procedures set forth above, a Claimant wishes to pursue legal action, any action by the Claimant with respect to a claim, must be resolved by arbitration in the manner described herein.

a) Time Limits. A Claimant seeking arbitration of any determination by the Claims Administrator must, within six (6) months of the date of the Claims Administrator's final decision, file a demand for arbitration with the American Arbitration Association submitting the Claim to resolution by arbitration. A Claimant waives any claim not filed timely in accordance with this Section.

b) Rules Applicable to Arbitration. The arbitration process shall be conducted in accordance with the Commercial Law Rules of the American Arbitration Association.

c) Venue. The arbitration shall be conducted in Minneapolis, Minnesota.

d) Binding Effect . The decision of the arbitrator with respect to the claim will be final and binding upon the Company and the Claimant. BY PARTICIPATING IN THE PLAN, AND ACCEPTING THE GRANT, YOU, ON BEHALF OF YOURSELF AND ANY PERSON WITH A CLAIM RELATING TO YOUR GRANT, AGREE TO WAIVE ANY RIGHT TO SUE IN COURT OR TO PURSUE ANY OTHER LEGAL RIGHT OR REMEDY THAT MIGHT OTHERWISE BE AVAILABLE IN CONNECTION WITH THE RESOLUTION OF THE CLAIM.

e) Enforceability . Judgment upon any award entered by an arbitrator may be entered in any court having jurisdiction over the parties.

f) Waiver of Class, Collective, and Representative Actions . Any claim shall be heard without consolidation of such claims with any other person or entity. To the fullest extent permitted by law, whether in court or in arbitration, by participating in the Plan, you waive any right to commence, be a party to in any way, or be an actual or putative class member of any class, collective, or representative action arising out of or relating to any claim, and you agree that any claim may only be initiated or maintained and decided on an individual basis.

g) Standard of Review . Any decision of an arbitrator on a claim shall be limited to determining whether the Claims Administrator's decision or action was arbitrary or capricious or was unlawful. The arbitrator shall adhere to and apply the deferential standard of review set out in *Conkright v. Frommert* , 130 S. Ct. 1640 (2010), *Metropolitan Life Insurance Co. v.* Glenn *,* 554 U.S. 105 (2008), and *Firestone Tire and Rubber Company v. Bruch,* 489 U.S. 101 (1989), and shall accord due deference to the determinations, interpretations, and construction of the Plan document by the Claim's Administrator.

h) General Procedures .

i. Arbitration Rules . The arbitration hearing will be conducted under the AAA Commercial Arbitration Rules (as amended or revised from time to time by AAA) (hereinafter the "AAA Rules"), before one AAA arbitrator who is from the Large, Complex Case Panel and who has experience with matters involving executive compensation and equity compensation plans. The AAA Rules and the terms and procedures set forth here may conflict on certain issues. To the extent that the procedures set forth here conflict with the AAA Rules, the procedures set forth here shall control and be applied by the arbitrator. Notwithstanding the amount of the claim, the Procedures for Large, Complex Commercial Disputes shall not apply.

ii. Substantive Law . The arbitrator shall apply the substantive law (and the laws of remedies, if applicable), of Minnesota or federal law, or both, depending upon the claim. Except to the extent required by applicable law, the Claimant shall keep any arbitration decision or award strictly confidential and not disclose to anyone other than his or her spouse, attorney, or tax advisor.

iii. Authority . The arbitrator shall have jurisdiction to hear and rule on prehearing disputes and is authorized to hold prehearing conferences by telephone or in person as the arbitrator deems necessary. The arbitrator will have the authority to hear a motion to dismiss and/or a motion for summary judgment by any party and in doing so shall apply the standards governing such motions under the Federal Rules of Civil Procedure.

iv. Pre-Hearing Procedures . Each party may take the deposition of not more than one individual and the expert witness, if any, designated by another party. Each party will have the right to subpoena witnesses in accordance with the Federal Arbitration Act, Title 9 of the United States Code. Additional discovery may be had only if the arbitrator so orders, upon a showing of substantial need.

v. Fees and Costs . Administrative arbitration fees and arbitrator compensation shall be borne equally by the parties, and each party shall be responsible for its own attorney's fees, if any; provided, however, that the Committee will authorize payment by the Company of all administrative arbitration fees, arbitrator compensation and attorney's fees if the Committee concludes that a Claimant has substantially prevailed on his or her claims. Unless prohibited by statute, the arbitrator shall assess attorney's fees against a party upon a showing that such party's claim, defense or position is frivolous, or unreasonable, or factually groundless. If either party pursues a claim by any means other than those set forth in this Article, the responding party shall be entitled to dismissal of such action, and the recovery of all costs and attorney's fees and losses related to such action, unless prohibited by statute.

(i) Interstate Commerce and the Federal Arbitration Act . The Company is involved in transactions involving interstate commerce, and the employee's employment with the Company involves such commerce. Therefore, the Federal Arbitration Act, Title 9 of the United States Code, will govern the interpretation, enforcement, and all judicial proceedings regarding the arbitration procedures in this Section.

8. Ratification of Actions. By receiving the Grant or other benefit under the Plan, you and each person claiming under or through you shall be conclusively deemed to have indicated your acceptance and ratification of, and consent to, any action taken under the Plan or the Grant by ALLETE, the Board, or the Committee.

9. No Impact on Other Benefits . The Grant or payment on account thereof shall not be taken into account in determining any benefits under any severance, retirement, welfare, insurance or other benefit plan of ALLETE or any affiliate except to the extent otherwise expressly provided in writing in such other plan or an agreement thereunder.

10. Notices. Any notice hereunder to ALLETE shall be addressed to ALLETE, 30 West Superior Street, Duluth, Minnesota 55802, Attention: Manager - Compensation and Benefits, Human Resources, and any notice hereunder to you shall be directed to your address as indicated by ALLETE's records, subject to the right of either party to designate at any time hereafter in writing some other address.

11. Governing Law and Severability. To the extent not preempted by the Federal law, the Grant will be governed by and construed in accordance with the laws of the State of Minnesota, without regard to its conflicts of law provisions. In the event any provision of the Grant shall be held illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of the Grant, and the Grant shall be construed and enforced as if the illegal or invalid provision had not been included.

12. Definitions. Capitalized terms not otherwise defined herein shall have the meanings given them in the Plan. The following definitions apply to the Grant and this Annex A:

12.1 " **Claims Administrator"** means ALLETE's Chief Executive Officer, unless the claimant is (or is acting on behalf of) an ALLETE executive officer (within the meaning of Exchange Act Rule 3b-7), in which case the Claims Administrator is the Executive Compensation Committee of the Board of Directors.

12.2 " **Change in Control** " means the earliest of:

(i) the date any one Person, or more than one Person acting as a group (as the term "group" is used in Treasury Regulations section 1.409A-3(i)(5)(v)(B)), acquires ownership of stock of the Company that, together with stock previously held by the acquirer, constitutes more than fifty (50%) percent of the total fair market value or total voting power of Company stock. If any one Person, or more than one Person acting as a group, is considered to own more than fifty (50%) percent of the total fair market value or total voting power of Company stock, the acquisition of additional stock by the same Person or Persons acting as a group does not cause a Change in Control. An increase in the percentage of stock owned by any one Person, or Persons acting as a group, as a result of a transaction in which Company acquires its stock in exchange for property, is treated as an acquisition of stock;

(ii) the date any one Person, or more than one Person acting as a group (as the term "group" is used in Treasury Regulations section 1.409A-3(i)(5)(v)(B)), acquires (or has acquired during the twelve (12) month period ending on the date of the most recent acquisition by that Person or Persons) ownership of Company stock possessing at least thirty (30%) percent of the total voting power of Company stock;

(iii) the date a majority of the members of the Company's board of directors is replaced during any twelve (12) month period by directors whose appointment or election is not endorsed by a majority of the members of the board of directors prior to the date of appointment or election; or

(iv) the date any one Person, or more than one Person acting as a group (as the term "group" is used in Treasury Regulations section 1.409A-3(i)(5)(v)(B)), acquires (or has acquired during the twelve (12) month period ending on the date of the most recent acquisition by that Person or Persons) assets from the Company that have a total gross fair market value equal to at least forty (40%) percent of the total gross fair market value of all the Company's assets immediately prior to the acquisition or acquisitions. For this purpose, "gross fair market value" means the value of the corporation's assets, or the value of the assets being disposed of, without regard to any liabilities associated with these assets.

In determining whether a Change in Control occurs, the attribution rules of Code section 318 apply to determine stock ownership. The stock underlying a vested option is treated as owned by the individual who holds the vested option, and the stock underlying an unvested option is not treated as owned by the individual who holds the unvested option. The term "Person" used in this definition means any individual, corporation (including any non-profit corporation), general, limited or limited liability partnership, limited liability company, joint venture, estate, trust, firm, association, organization or other entity or any governmental or quasi-governmental authority, organization, agency or body.

12.3 " **Code** " means the Internal Revenue Code of 1986, as it may be amended from time to time

12.4 " **Disability** " or " **Disabled** " means a physical or mental condition in which the Participant is:

(i) unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than twelve (12) months;

(ii) by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than twelve (12) months, receiving income replacement benefits for a period of not less than three (3) months under the Employer's accident and health plan;

(iii) determined to be totally disabled by the Social Security Administration; or

(iv) disabled pursuant to an Employer-sponsored disability insurance arrangement provided that the definition of disability applied under such disability insurance program complies with the foregoing definition of Disability.

12.5 " **Related Company** " means the ALLETE, Inc. and all persons with whom the ALLETE, Inc. would be considered a single employer under Code section 414(b) (employees of controlled group of corporations), and all persons with whom such person would be considered a single employer under Code section 414(c) (employees of partnerships, proprietorships, etc., under common control); provided that in applying Code sections 1563(a)(1), (2), and (3) for purposes of determining a controlled group of corporations under Code section 414(b), the language "at least 50 percent" is used instead of "at least 80 percent" each place it appears in Code sections 1563(a)(1), (2), and (3), and in applying Treasury Regulations section 1.414(c)-2 for purposes of determining trades or businesses (whether or not incorporated) that are under common control for purposes of Code section 414(c), "at least 50 percent" is used instead of "at least 80 percent" each place it appears in Treasury Regulations section 1.414(c)-2.

12.6 " **Retirement** " or " **Retires** " means Separation from Service, for reasons other than death or Disability, on or after attaining normal retirement age or early retirement age as defined in the most applicable qualified retirement plan sponsored by the Related Company that employed the Participant immediately preceding the Separation from Service, without regard to whether the Participant is a participant in such plan, or if the employer Related Company does not sponsor such retirement plan, on or after attaining Normal Retirement Age or Early Retirement Age as defined in the ALLETE and Affiliated Companies Retirement Plan A, without regard to whether the Participant is a participant under the ALLETE and Affiliated Companies Retirement Plan A.

12.7 " **Section 409A** " means Section 409A of the Code and Treasury Regulations section 1.409A-1 et seq., as they both may be amended from time to time, or other guidance issued by the Treasury Department and Internal Revenue Service thereunder.

12.8 " **Separation from Service** " means that the Participant terminates employment within the meaning of Treasury Regulations section 1.409A-1(h) and other applicable guidance with all Related Companies. Whether a termination of employment has occurred is determined under the facts and circumstances, and a termination of employment shall occur if all Related Companies and the Participant reasonably anticipate that no further services shall be performed after a certain date or that the level of bona fide services the Participant shall perform after such date (as an employee or an independent contractor) shall permanently decrease to no more than 20 percent of the average level of bona fide services performed (whether as an employee or an independent contractor) over the immediately preceding 36-month period (or the full period of services to the Related Companies if the Participant has been providing services to the Related Companies less than 36 months). A Participant shall not be considered to separate from service during a bona fide leave of absence for less than six (6) months or longer if the Participant retains a right to reemployment with any Related Company by contract or statute. With respect to disability leave, a Participant shall not be considered to separate from service for 29 months unless the Participant otherwise terminates employment or is terminated by all Related Companies.

12.9 " **Specified Employee** " means an Participant who is subject to the six-month delay rule described in Code section 409A(2)(B)(i), determined in accordance with guidelines adopted by the Board from time to time as permitted by Section 409A of the Code and Treasury Regulations section 1.409A-1 et seq., as they both may be amended from time to time, and other guidance issued by the Treasury Department and Internal Revenue Service thereunder.

ALLETE
EXECUTIVE LONG-TERM INCENTIVE COMPENSATION PLAN
PERFORMANCE SHARE GRANT
[Effective 2018]
[Eligible Executive Employees]

Name

In accordance with the terms of ALLETE's Executive Long-Term Incentive Compensation Plan, as amended (the "Plan"), and as determined by and through the Executive Compensation Committee of ALLETE's Board of Directors, ALLETE hereby grants to you (the "Participant") Performance Shares, as set forth below, subject to the terms and conditions set forth in this Grant, including Annex A and Annex B hereto and all documents incorporated herein by reference:

Number of Performance Shares Granted:	
Date of Grant:	
Performance Period:	
Performance Goals:	See Annex B

This Grant is made in accordance with the Plan.

Further terms and conditions of the Grant are set forth in Annex A hereto and Performance Goals are set forth in Annex B hereto, both of which are integral parts of this Grant.

Any term, provision or condition applicable to the Performance Shares set forth in the Plan and not set forth herein is hereby incorporated by reference. To the extent any provision hereof is inconsistent with a Plan provision, the Plan provision will govern.

YOU SHOULD CAREFULLY READ AND REVIEW THE TERMS AND CONDITIONS SET FORTH IN THIS GRANT, INCLUDING ANNEX A HERETO , WHICH CONTAINS IMPORTANT INFORMATION, INCLUDING MANDATORY CLAIMS AND ARBITRATION PROCEDURES.

You will be deemed to have accepted this Grant on the Date of Grant and all its associated terms and conditions, including the mandatory claims and arbitration procedures set forth in Annex A, unless you notify the Company of your non-acceptance of the Grant by contacting the Manager–Compensation and Benefits, in writing within sixty (60) days of the Date of Grant.

IN WITNESS WHEREOF, ALLETE has caused this Grant to be executed by its Chairman, President and Chief Executive Officer as of the date and year first above written.

ALLETE

By: _____
Chairman, President & CEO

Attachments: Annex A and Annex B

ANNEX A
TO
ALLETE
EXECUTIVE LONG-TERM INCENTIVE COMPENSATION PLAN
PERFORMANCE SHARE GRANT

The Performance Share Grant to which this is annexed is subject to the following additional terms and conditions:

1. Dividend Equivalents. You will receive Dividend Equivalents with respect to Performance Shares that are earned and payable. Dividend Equivalents are calculated and credited to you after the Performance Period has ended. The Dividend Equivalents will be in the form of additional Performance Shares, which will be added to the number of Performance Shares earned, and will equal the number of Shares (including fractional Shares) that could have been purchased on applicable dividend payment dates, based on the closing ALLETE common stock price as reported in the consolidated transaction reporting system on that date, with cash dividends that would have been paid on underlying Performance Shares, if such Performance Shares were Shares. Dividend Equivalents will only become payable if and to the extent the underlying Performance Shares are earned and become payable.

2. Satisfaction of Goals. Performance Shares remain unearned unless and until Performance Goals are achieved. After the Performance Period has ended, the Executive Compensation Committee (the "Committee") will determine the extent to which the Performance Goals have been met. You will not earn any Performance Shares if the threshold performance level has not been met. Subject to the provisions of Section 4 below and to provisions in the Plan for change in control, Performance Shares will be earned as follows: If the threshold level has been met, you will have earned 50% of the Performance Shares (as increased by the Dividend Equivalents). If the target level has been met, you will have earned 100% of the Performance Shares (as increased by the Dividend Equivalents). If the superior level has been met, you will have earned 200% of the Performance Shares (as increased by the Dividend Equivalents). Straight line interpolation will be used to determine earned awards based on achievement of goals between the threshold, target and superior levels.

3. Payment. Subject to the provisions of Section 4 below and to provisions in the Plan for Change in Control, Performance Shares (as increased by the Dividend Equivalents) shall be paid in full after the Committee has determined the extent to which Performance Goals have been met and within two and one half months after the end of the Performance Period. Payment shall be made, after withholding Performance Shares in an amount equal in value to the minimum amount of tax required to be withheld by law, by depositing ALLETE common stock into your Invest Direct account. Performance Share awards shall not vest until paid.

4. Payment Upon Death, Retirement or Disability; Forfeiture of Unvested Performance Shares Upon Demotion, Unsatisfactory Job Performance, Default on Certain Agreements or Other Separation from Service.

4.1 If during a Performance Period you (i) Retire, (ii) die while employed by a Related Company, or (iii) become Disabled, you (or your beneficiary or estate) will receive a payment of any Performance Shares (as increased by the Dividend Equivalents) after the end of the Performance Period in accordance with Section 3 above. The payment shall be prorated based upon the number of whole calendar months within the Performance Period which had elapsed as of the date of death, Retirement or Disability in relation to the number of calendar months in the full Performance Period. A whole month is counted in the calculation if you were in the position as of the 15 th of the month.

4.2 If after the end of a Performance Period, but before any or all Performance Shares have been paid, you Retire, die or become Disabled, you (or your beneficiary or estate) will be entitled to full payout of all earned Performance Shares (as increased by the Dividend Equivalents) in accordance with Section 3 above.

4.3 If, prior to payment of all Performance Shares, you are demoted, you default on any written agreement with a Related Company related to a restrictive employment covenant (such as confidentiality, non-disclosure, non-competition, non-solicitation, or the like) or ALLETE determines, in its sole discretion, that your job performance is unsatisfactory, ALLETE reserves the right to cancel or amend your grant relating to any unpaid Performance Shares, with the result that some portion or all of your unpaid Performance Shares (and related Dividend Equivalents) will be forfeited.

4.4 If you have a Separation from Service for any reason other than those specified in subsection 4.1 above, all Performance Shares (and related Dividend Equivalents), to the extent not yet paid, shall be forfeited on the date of such Separation from Service, except as otherwise provided by the Committee.

5. Compensation Recovery Policy . The Grant is subject to the terms of any compensation recovery policy or policies established by ALLETE as may be amended from time to time ("Compensation Recovery Policy"). ALLETE hereby incorporates into the Grant the terms of the Compensation Recovery Policy.

6. Section 409A Compliance. This Grant is intended to comply with Section 409A of the Code ("Section 409A") or an exemption thereunder, and, accordingly, to the maximum extent permitted, the Plan and the Grant shall be interpreted and administered in compliance therewith. Notwithstanding any other provision of the Grant, payments provided pursuant to the Grant may only be made upon an event and in a manner that complies with Section 409A or an applicable exemption. Any payments pursuant to the Grant that may be excluded from Section 409A as a short-term deferral shall be excluded from Section 409A to the maximum extent possible. To the extent that any provision of the Grant would cause a conflict with the requirements of Section 409A or would cause the administration of the Grant to fail to satisfy Section 409A, such provision shall be deemed null and void to the extent permitted by applicable law. Nothing herein shall be construed as a guarantee of any particular tax treatment. ALLETE makes no representation that the Grant complies with Section 409A and in no event shall ALLETE be liable for the payment of any taxes and penalties that you may incur under Section 409A.

7. Claims Procedure and Arbitration . The Grant is subject to the following claims procedures:

7.1 Mandatory Claims Procedures. If you or any person acting on your behalf (the "Claimant") has any claim or dispute related in any way to the Grant or to the Plan, the Claimant must follow these claims procedures. All claims must be brought no later than one year following the date on which the claim first arose and any claim not submitted within such time limit will be waived.

7.2 Claim Submission. Any claim must be made in writing to the Claims Administrator. The Claims Administrator, or its delegate, shall notify the Claimant of the resolution of the claim within 90 days after receipt of the claim; provided, however, if the Claims Administrator determines that an extension is necessary, the 90-day period shall be extended to up to 180 days upon notice to that effect to the Claimant.

7.3 Notice of Denial. If a claim is wholly or partially denied, the denial notice shall contain (i) the reason or reasons for denial of the claim, and (ii) references to the pertinent Plan provisions upon which the denial is based. Unless the claim is submitted for arbitration as provided below and in the Plan, the Claims Administrator's decision or action shall be final, conclusive and binding on all persons having any interest in the Plan.

7.4 Arbitration. If, after exhausting the procedures set forth above, a Claimant wishes to pursue legal action, any action by the Claimant with respect to a claim, must be resolved by arbitration in the manner described herein.

a) Time Limits. A Claimant seeking arbitration of any determination by the Claims Administrator must, within six (6) months of the date of the Claims Administrator's final decision, file a demand for arbitration with the American Arbitration Association submitting the claim to resolution by arbitration. A Claimant waives any claim not filed timely in accordance with this Section.

b) Rules Applicable to Arbitration. The arbitration process shall be conducted in accordance with the Commercial Law Rules of the American Arbitration Association.

c) Venue. The arbitration shall be conducted in Minneapolis, Minnesota.

d) Binding Effect. The decision of the arbitrator with respect to the claim will be final and binding upon the Company and the Claimant. BY PARTICIPATING IN THE PLAN, AND ACCEPTING THE GRANT, YOU, ON BEHALF OF YOURSELF AND ANY PERSON WITH A CLAIM RELATING TO YOUR GRANT, AGREE TO WAIVE ANY RIGHT TO SUE IN COURT OR TO PURSUE ANY OTHER LEGAL RIGHT OR REMEDY THAT MIGHT OTHERWISE BE AVAILABLE IN CONNECTION WITH THE RESOLUTION OF THE CLAIM.

e) Enforceability. Judgment upon any award entered by an arbitrator may be entered in any court having jurisdiction over the parties.

f) Waiver of Class, Collective, and Representative Actions . Any claim shall be heard without consolidation of such claims with any other person or entity. To the fullest extent permitted by law, whether in court or in arbitration, by participating in the Plan, you waive any right to commence, be a party to in any way, or be an actual or putative class member of any class, collective, or representative action arising out of or relating to any claim, and you agree that any claim may only be initiated or maintained and decided on an individual basis.

g) Standard of Review . Any decision of an arbitrator on a claim shall be limited to determining whether the Claims Administrator's decision or action was arbitrary or capricious or was unlawful. The arbitrator shall adhere to and apply the deferential standard of review set out in *Conkright v. Frommert* , 130 S. Ct. 1640 (2010), *Metropolitan Life Insurance Co. v.* Glenn *,* 554 U.S. 105 (2008), and *Firestone Tire and Rubber Company v. Bruch,* 489 U.S. 101 (1989), and shall accord due deference to the determinations, interpretations, and construction of the Plan document by the Claims Administrator.

h) General Procedures .

i. Arbitration Rules . The arbitration hearing will be conducted under the AAA Commercial Arbitration Rules (as amended or revised from time to time by AAA) (hereinafter the "AAA Rules"), before one AAA arbitrator who is from the Large, Complex Case Panel and who has experience with matters involving executive compensation and equity compensation plans. The AAA Rules and the terms and procedures set forth here may conflict on certain issues. To the extent that the procedures set forth here conflict with the AAA Rules, the procedures set forth here shall control and be applied by the arbitrator. Notwithstanding the amount of the claim, the Procedures for Large, Complex Commercial Disputes shall not apply.

ii. Substantive Law . The arbitrator shall apply the substantive law (and the laws of remedies, if applicable), of Minnesota or federal law, or both, depending upon the claim. Except to the extent required by applicable law, the Claimant shall keep any arbitration decision or award strictly confidential and not disclose to anyone other than his or her spouse, attorney, or tax advisor.

iii. Authority . The arbitrator shall have jurisdiction to hear and rule on prehearing disputes and is authorized to hold prehearing conferences by telephone or in person as the arbitrator deems necessary. The arbitrator will have the authority to hear a motion to dismiss and/or a motion for summary judgment by any party and in doing so shall apply the standards governing such motions under the Federal Rules of Civil Procedure.

iv. Pre-Hearing Procedures . Each party may take the deposition of not more than one individual and the expert witness, if any, designated by another party. Each party will have the right to subpoena witnesses in accordance with the Federal Arbitration Act, Title 9 of the United States Code. Additional discovery may be had only if the arbitrator so orders, upon a showing of substantial need.

v. Fees and Costs . Administrative arbitration fees and arbitrator compensation shall be borne equally by the parties, and each party shall be responsible for its own attorney's fees, if any; provided, however, that the Committee will authorize payment by the Company of all administrative arbitration fees, arbitrator compensation and attorney's fees if the Committee concludes that a Claimant has substantially prevailed on his or her claims. Unless prohibited by statute, the arbitrator shall assess attorney's fees against a party upon a showing that such party's claim, defense or position is frivolous, or unreasonable, or factually groundless. If either party pursues a claim by any means other than those set forth in this Article, the responding party shall be entitled to dismissal of such action, and the recovery of all costs and attorney's fees and losses related to such action, unless prohibited by statute.

i) Interstate Commerce and the Federal Arbitration Act . The Company is involved in transactions involving interstate commerce, and the employee's employment with the Company involves such commerce. Therefore, the Federal Arbitration Act, Title 9 of the United States Code, will govern the interpretation, enforcement, and all judicial proceedings regarding the arbitration procedures in this Section.

8. Ratification of Actions. By receiving the Grant or other benefit under the Plan, you and each person claiming under or through you shall be conclusively deemed to have indicated your acceptance and ratification of, and consent to, any action taken under the Plan or the Grant by ALLETE, the Board or the Committee.

9. No Impact on Other Benefits . The Grant or payment on account thereof shall not be taken into account in determining any benefits under any severance, retirement, welfare, insurance or other benefit plan of ALLETE or any affiliate except to the extent otherwise expressly provided in writing in such other plan or an agreement thereunder.

10. Notices. Any notice hereunder to ALLETE shall be addressed to ALLETE, 30 West Superior Street, Duluth, Minnesota 55802, Attention: Manager - Compensation and Benefits, Human Resources, and any notice hereunder to you shall be directed to your address as indicated by ALLETE's records, subject to the right of either party to designate at any time hereafter in writing some other address.

11. Governing Law and Severability. To the extent not preempted by the Federal law, the Grant will be governed by and construed in accordance with the laws of the State of Minnesota, without regard to its conflicts of law provisions. In the event any provision of the Grant shall be held illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of the Grant, and the Grant shall be construed and enforced as if the illegal or invalid provision had not been included.

12. Definitions. Capitalized terms not otherwise defined herein shall have the meanings given them in the Plan. The following definitions apply to the Grant and this Annex A:

12.1 " **Claims Administrator"** means ALLETE's Chief Executive Officer, unless the claimant is (or is acting on behalf of) an ALLETE executive officer (within the meaning of Exchange Act Rule 3b-7), in which case the Claims Administrator is the Executive Compensation Committee of the Board of Directors.

12.2 " **Code** " means the Internal Revenue Code of 1986, as it may be amended from time to time.

12.3 " **Disability** " or " **Disabled** " means a physical or mental condition in which the Participant is:

(a) unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than twelve (12) months;

(b) by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than twelve (12) months, receiving income replacement benefits for a period of not less than three (3) months under the Employer's accident and health plan;

(c) determined to be totally disabled by the Social Security Administration; or

(d) disabled pursuant to an Employer-sponsored disability insurance arrangement provided that the definition of disability applied under such disability insurance program complies with the foregoing definition of Disability.

12.4 " **Related Company** " means ALLETE, Inc. and all persons with whom the ALLETE, Inc. would be considered a single employer under Code section 414(b) (employees of controlled group of corporations), and all persons with whom such person would be considered a single employer under Code section 414(c) (employees of partnerships, proprietorships, etc., under common control); provided that in applying Code sections 1563(a)(1), (2), and (3) for purposes of determining a controlled group of corporations under Code section 414(b), the language "at least 50 percent" is used instead of "at least 80 percent" each place it appears in Code sections 1563(a)(1), (2), and (3), and in applying Treasury Regulations section 1.414(c)-2 for purposes of determining trades or businesses (whether or not incorporated) that are under common control for purposes of Code section 414(c), "at least 50 percent" is used instead of "at least 80 percent" each place it appears in Treasury Regulations section 1.414(c)-2.

12.5 " **Retirement** " or " **Retires** " means Separation from Service, for reasons other than death or Disability, on or after attaining normal retirement age or early retirement age as defined in the most applicable qualified retirement plan sponsored by the Related Company that employed the Participant immediately preceding the Separation from Service, without regard to whether the Participant is a participant in such plan, or if the employer Related Company does not sponsor such retirement plan, on or after attaining Normal Retirement Age or Early Retirement Age as defined in the ALLETE and Affiliated Companies Retirement Plan A, without regard to whether the Participant is a participant under the ALLETE and Affiliated Companies Retirement Plan A.

12.6 " **Separation from Service** " means that the Participant terminates employment within the meaning of Treasury Regulations section 1.409A-1(h) and other applicable guidance with all Related Companies. Whether a termination of employment has occurred is determined under the facts and circumstances, and a termination of employment shall occur if all Related Companies and the Participant reasonably anticipate that no further services shall be performed after a certain date or that the level of bona fide services the Participant shall perform after such date (as an employee or an independent contractor) shall permanently decrease to no more than 20 percent of the average level of bona fide services performed (whether as an employee or an independent contractor) over the immediately preceding 36-month period (or the full period of services to the Related Companies if the Participant has been providing services to the Related Companies less than 36 months). A Participant shall not be considered to separate from service during a bona fide leave of absence for less than six (6) months or longer if the Participant retains a right to reemployment with any Related Company by contract or statute. With respect to disability leave, a Participant shall not be considered to separate from service for 29 months unless the Participant otherwise terminates employment or is terminated by all Related Companies.

ANNEX B
TO
ALLETE
Executive Long Term Incentive Compensation Plan
Performance Share Grant
Effective 2018
[Eligible Executive Employees]

Financial Measure :
Total Shareholder Return (TSR) computed over the three-year performance period January 1, 2018 to December 31, 2020.

Performance Share Award:
If ALLETE's TSR ranking is at the 85th percentile or higher among the peer group (superior performance), 200% of the Performance Share Grant will be earned. If ALLETE's TSR ranking is at the 50 th percentile among the peer group (target performance), 100% of the Performance Share Grant will be earned. If ALLETE's TSR ranking is at the 30 th percentile (threshold performance), 50% of the Performance Share Grant will be earned. If TSR ranking is below threshold, no Performance Shares will be earned. Straight-line interpolation will be used to determine earned awards based on the TSR ranking between threshold, target and superior.

Peer Group:
The integrated utility companies comprising Edison Electric Institute (EEI) Stock Index as of December 31, 2020 that have been in the EEI Stock Index for at least three years as of December 31, 2020 will constitute the peer group used to determine actual payout results. The table below lists the EEI Stock Index as of December 31, 2017:

Alliant Energy Corporation	Entergy Corporation	PG&E Corporation
Ameren Corporation	Eversource Energy	Pinnacle West Capital Corporation
American Electric Power Company	Exelon Corporation	PNM Resources, Inc.
Avangrid, Inc.	FirstEnergy Corporation	Portland General Electric Company
Avista Corporation	Great Plains Energy Incorporated	PPL Corporation
Black Hills Corporation	Hawaiian Electric Industries, Inc.	Public Service Enterprise Group, Inc.
CenterPoint Energy, Inc.	IDACORP, Inc.	SCANA Corporation
CMS Energy Corporation	MDU Resources Group, Inc.	Sempra Energy
Consolidated Edison, Inc.	MGE Energy, Inc.	Southern Company
Dominion Resources, Inc.	NextEra Energy, Inc	Unitil Corporation
DTE Energy Company	NiSource, Inc.	Vectren Corporation
Duke Energy Corporation	NorthWestern Corporation	WEC Energy Group, Inc
Edison International	OGE Energy Corp.	Westar Energy, Inc.
El Paso Electric Company	Otter Tail Corporation	Xcel Energy, Inc.

Any Company that is no longer included in the EEI Stock Index as of December 31, 2020 due to corporate restructuring during the performance period (e.g., mergers, acquisitions, divestitures, spin-offs, etc.) will be excluded from the results calculation entirely. If a corporate restructuring during the performance period results in a company remaining in the EEI Stock Index following the transaction (and thus not being excluded from the results calculation entirely), from the point of the transaction forward, the results calculation will track only the entity that remains in the EEI Stock Index and ignore other entities, regardless of whether such other entities are publicly traded.

Exhibit 12

ALLETE
Computation of Ratios of Earnings to Fixed Charges (Unaudited)

Year Ended December 31	**2017**	**2016**	**2015**	**2014**	**2013**
Millions					
Earnings as Defined					
Pretax Income Before Non-Controlling Interest	$186.9	$175.6	$166.8	$162.2	$133.3
Add: Fixed Charges	68.7	73.0	71.9	62.5	56.7
Less: Undistributed Income from Less than 50 percent Owned Equity Investment	3.3	5.7	1.8	2.6	4.1
Earnings as Defined	$252.3	$242.9	$236.9	$222.1	$185.9
Fixed Charges					
Interest on Long-Term Debt	$60.6	$64.7	$64.7	$55.6	$50.9
Other Interest Charges	2.3	2.6	1.4	2.0	1.2
Interest Component of All Rentals *(a)*	5.8	5.7	5.8	4.9	4.6
Total Fixed Charges	$68.7	$73.0	$71.9	$62.5	$56.7
Ratio of Earnings to Fixed Charges	3.67	3.33	3.29	3.55	3.28

(a) Represents interest portion of rents estimated at 33 1/3 percent.

Exhibit 21

SUBSIDIARIES OF THE REGISTRANT
As of December 31, 2017

Name of Organization *(a)*	**State or Country**
ALLETE, Inc. *(d/b/a ALLETE; Minnesota Power; Minnesota Power, Inc.;*	Minnesota
Minnesota Power & Light Company)	
ALLETE Automotive Services, LLC	Minnesota
ALLETE Enterprises, Inc.	Minnesota
ALLETE Clean Energy, Inc.	Minnesota
ACE Wind LLC	Delaware
ACE Mid-West Holdings, LLC	Delaware
MWW Holdings, LLC	Delaware
Lake Benton Power Associates LLC	Delaware
Lake Benton Holdings LLC	Delaware
Lake Benton Power Partners L.L.C.	Delaware
Storm Lake Power Partners I LLC	Delaware
Storm Lake II Power Associates LLC	Delaware
Storm Lake II Holdings LLC	Delaware
Storm Lake Power Partners II LLC	Delaware
New Salem Holdings, LLC	Delaware
Glen Ullin Energy Center, LLC	Delaware
Northern Wind Energy, LLC	Delaware
Chanarambie Power Partners, LLC	Delaware
Viking Wind Holdings, LLC	Delaware
ACE West Holdings, LLC	Delaware
Condon Wind Power, LLC	Delaware
Armenia Holdings, LLC	Delaware
AMW I Holding, LLC	Delaware
Armenia Mountain Wind, LLC	Delaware
Armenia Mountain Wind II, LLC	Delaware
Thunder Spirit Wind, LLC	Delaware
ACE O&M, LLC	Delaware
ALLETE Power Systems, Inc.	Minnesota
ALLETE Renewable Resources, Inc.	North Dakota
ALLETE Transmission Holdings, Inc.	Wisconsin
BNI Energy, Inc.	North Dakota
BNI Coal, Ltd.	North Dakota
Global Water Services Holding Company, Inc.	Delaware
U.S Water Services, Inc.	Minnesota
U.S. Water Services – Canada, Inc.	Canada
MP Affiliate Resources, Inc.	Minnesota
Rainy River Energy Corporation	Minnesota
South Shore Energy, LLC	Wisconsin
Upper Minnesota Properties, Inc.	Minnesota
Upper Minnesota Properties - Development, Inc.	Minnesota
ALLETE Properties, LLC *(d/b/a ALLETE Properties)*	Minnesota
ALLETE Commercial, LLC	Florida
Lehigh Acquisition, LLC	Delaware
Florida Landmark Communities, LLC	Florida
Lehigh Corporation	Florida
Mardem, LLC	Florida
Palm Coast Holdings, Inc.	Florida
Port Orange Holdings, LLC	Florida
Interlachen Lakes Estates, LLC	Florida

(a) Certain insignificant subsidiaries are omitted.

Name of Organization *(a)*	**State or Country**
Palm Coast Land, LLC	Florida
ALLETE Water Services, Inc.	Minnesota
Florida Water Services Corporation	Florida
Energy Replacement Property, LLC	Minnesota
Energy Land, Incorporated	Wisconsin
Lakeview Financial Corporation I	Minnesota
Lakeview Financial Corporation II	Minnesota
MP Investments, Inc.	Delaware
RendField Land Company, Inc.	Minnesota
Superior Water, Light and Power Company	Wisconsin

(a) Certain insignificant subsidiaries are omitted.

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-212794, 333-211075) and Form S-8 (Nos. 333-162890, 333-183051, 333-190336, 333-207846) of ALLETE, Inc. of our report dated February 15, 2018, relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Minneapolis, Minnesota
February 15, 2018

Exhibit 31(a)

Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer
Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Alan R. Hodnik, certify that:

1. I have reviewed this annual report on Form 10-K for the fiscal year ended December 31, 2017 , of ALLETE, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 15, 2018

/s/ Alan R. Hodnik

Alan R. Hodnik

President and Chief Executive Officer

Exhibit 31(b)

Rule 13a-14(a)/15d-14(a) Certification by the Chief Financial Officer
Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Robert J. Adams, certify that:

1. I have reviewed this annual report on Form 10-K for the fiscal year ended December 31, 2017 , of ALLETE, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 15, 2018

/s/ Robert J. Adams

Robert J. Adams

Senior Vice President and Chief Financial Officer

Exhibit 32

Section 1350 Certification of Periodic Report
By the Chief Executive Officer and Chief Financial Officer
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, each of the undersigned officers of ALLETE, Inc. (ALLETE), does hereby certify that:

1. The Annual Report on Form 10-K of ALLETE for the fiscal year ended December 31, 2017 , (Report) fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 (15 U.S.C. 78m); and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of ALLETE.

Date: February 15, 2018 /s/ Alan R. Hodnik

Alan R. Hodnik

President and Chief Executive Officer

Date: February 15, 2018 /s/ Robert J. Adams

Robert J. Adams

Senior Vice President and Chief Financial Officer

This certification shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to liability pursuant to that section. Such certification shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that ALLETE specifically incorporates it by reference.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to ALLETE and will be retained by ALLETE and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 95

Mine Safety Disclosure

Mine or Operating Name/MSHA Identification Number	Section 104 S&S Citations (#)	Section 104(b) Orders (#)	Section 104(d) Citations and Orders (#)	Section 110(b)(2) Violations (#)	Section 107(a) Orders (#)	Total Dollar Value of MSHA Assessments Proposed ($)	Total Number of Mining-Related Fatalities (#)	Received Notice of Pattern of Violation Under Section 104(e) (yes/no)	Received Notice of Potential to Have Pattern Under Section 104(e) (yes/no)	Legal Actions Pending as of Last Day of Period (#)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
Center Mine / 3200218	—	—	—	—	—	$484	—	No	No	—	—	—

For the quarter ended December 31, 2017 , BNI Energy, owner of Center Mine, received three citations under Section 104(a) of the Mine Safety Act, none of which were significant and substantial (S&S) citations; eighteen citations were received for the year ended December 31, 2017 , one of which was a S&S citation. The total proposed penalties on BNI with respect to the three citations were $484. For the year ended December 31, 2017 , BNI Energy paid $2,871 in penalties for citations closed during the period. For the year ended December 31, 2017 , there were no citations, orders, violations or notices received under Sections 104(b), 104(d), 107(a), 104(e) or 110(b)(2) of the Mine Safety Act and there were no fatalities.

Exhibit 99

For Release: February 15, 2018

Investor Contact: Vince Meyer
218-723-3952
vmeyer@allete.com

NEWS

ALLETE, Inc. reports 2017 earnings of $3.38 per share; initiates 2018 earnings guidance; expects significant growth from non-regulated businesses

DULUTH, Minn. - ALLETE, Inc. (NYSE: ALE) today reported 2017 earnings of $3.38 per share on net income of $172.2 million and operating revenue of $1.42 billion. Results from 2016 were $3.14 per share on net income of $155.3 million and operating revenue of $1.34 billion.

“I am pleased with our financial performance and accomplishments in 2017 as we continued to execute on our multi-faceted strategy for growth while returning more than $100 million to shareholders in the form of dividends; our businesses are well positioned as we move into 2018 and beyond,” said ALLETE Chairman, President and CEO Al Hodnik, “We believe our unique mix of businesses will continue to deliver a strong value proposition to shareholders as supported by our recent announcement to increase our long-term average annual earnings growth target to 5 percent to 7 percent from 5 percent previously, and increase our dividend by approximately 5 percent over 2017.”

Results in 2017 were positively impacted by $13.0 million after-tax, or $0.25 per share, for the remeasurement of ALLETE’s deferred income tax assets and liabilities resulting from the Tax Cuts and Jobs Act (TCJA) that was enacted on December 22, 2017. While immediate and future net tax benefits for the regulated businesses are expected to return to our utility customers over time, the immediate net tax benefits attributable to ALLETE Clean Energy and U.S. Water Services positively affected 2017 results and are expected to benefit future after-tax earnings. Results for 2017 also reflect a benefit of $7.9 million after-tax, or $0.16 per share, for the Minnesota Public Utilities Commission’s (MPUC) modification of its November 2016 order on the allocation of North Dakota investment tax credits in a MPUC order dated December 7, 2017. These benefits were partially offset by a non-cash $11.4 million after-tax charge, or $0.22 per share, for the MPUC’s decision in Minnesota Power’s rate case in January 2018, disallowing recovery of Minnesota Power’s regulatory asset for deferred fuel adjustment clause costs due to the anticipated adoption of a forward-looking fuel adjustment clause methodology.

Net income for 2016 was impacted by an after-tax gain of $13.6 million, or $0.28 per share, related to the change in fair value of the contingent consideration liability, offset by the adverse impact of $8.8 million after-tax, or $0.18 per share, for the November 2016 MPUC order on the allocation of North Dakota investment tax credits, a $3.3 million after-tax, or $0.07 per share, goodwill impairment charge related to ALLETE Clean Energy, and $0.9 million after-tax expense, or $0.02 per share, related to the repayment of long-term debt at ALLETE Clean Energy.

ALLETE’s Regulated Operations segment, which includes Minnesota Power, Superior Water, Light and Power, and the Company’s investment in the American Transmission Co. (ATC), recorded net income of $128.4 million, a decrease of $7.1 million compared to 2016. Net income at Minnesota Power decreased $9.8 million after-tax reflecting the previously mentioned non-cash $11.4 million after-tax charge for the MPUC’s decision disallowing recovery of Minnesota Power’s regulatory asset for deferred fuel adjustment clause costs. In addition, net income decreased due to lower sales to other power suppliers as a result of higher industrial sales coupled with lower market prices, higher interest and taxes other than income taxes, and lower kWh sales to residential, commercial and municipal customers due to milder temperatures in 2017. These decreases were partially offset by lower depreciation expense of $14.6 million after-tax resulting from the MPUC’s decision to modify the depreciable lives at Boswell Energy Center, and higher industrial kWh sales. Interim retail rate refund reserves fully offset the interim retail rates recognized during 2017 due to the regulatory outcome of the MPUC’s decision in Minnesota Power’s 2016 general rate case in January 2018. Our equity earnings in ATC increased $2.6 million after-tax in 2017, primarily due to additional investments in ATC and period-over-period changes in ATC’s estimate of a refund liability related to the MISO return on equity complaints.

ALLETE's Energy Infrastructure and Related Services businesses, which include ALLETE Clean Energy and U.S. Water Services, recorded net income of $41.5 million and $10.7 million, respectively.

Earnings at ALLETE Clean Energy in 2017 included a favorable impact of $23.6 million after-tax for the remeasurement of deferred income tax assets and liabilities resulting from the TCJA, increased production tax credits due to the requalification of certain wind turbine generators for production tax credits at its Storm Lake I, Storm Lake II and Lake Benton wind energy facilities, lower operating and maintenance expenses, and lower interest expense. Results for 2016 at ALLETE Clean Energy included a $3.3 million after-tax goodwill impairment charge and a $0.9 million after-tax expense related to the repayment of long-term debt.

Earnings at U.S. Water Services in 2017 increased $9.2 million reflecting a favorable impact of $9.2 million after-tax for the remeasurement of deferred income tax assets and liabilities resulting from the TCJA, and higher operating revenue, partially offset by increased operating expenses as a result of investments for future growth in waste treatment and water safety applications. 2017 earnings also reflected a net loss of $0.8 million primarily for transaction fees and amortization expense of a recent acquisition. Cash flow from operations remained strong for the year at approximately $12 million.

Our Corporate and Other businesses, which include BNI Energy and ALLETE Properties, recorded a net loss of $8.4 million for the year, compared to net income of $4.9 million in 2016. The net loss in 2017 included additional income tax expense of $19.8 million after-tax for the remeasurement of deferred income tax assets and liabilities resulting from the TCJA. The net loss in 2017 also included the previously mentioned favorable impact of $7.9 million after-tax for the MPUC's modification of its November 2016 order on the allocation of North Dakota investment tax credits, lower accretion expense relating to the contingent consideration liability, and lower interest expense. Net income in 2016 included the after-tax gain of $13.6 million related to the change in fair value of the U.S. Water Services contingent consideration liability, partially offset by the adverse impact of $8.8 million after-tax for the regulatory outcome of the November 2016 MPUC order.

Earnings were diluted by $0.11 per share in 2017, due to additional shares of common stock outstanding as of December 31, 2017.

The Company expects 2018 earnings per share to be within a range of $3.20 to $3.50 with earnings from our Energy Infrastructure and Related Services businesses expected to increase further in 2019 and become a more meaningful contributor to ALLETE's earnings in the coming years. Details of the Company's 2018 earnings guidance were also filed as part of today's Form 8-K filing.

ALLETE will host a conference call and webcast at 10 a.m. Eastern Time this morning to discuss details of its financial performance and earnings guidance. Interested parties may listen live by calling (877) 303-5852, or by accessing the webcast at www.allete.com. A replay of the call will be available through February 19, 2018 by calling (855) 859-2056, pass code 9977768. The webcast will be accessible for one year at www.allete.com .

ALLETE is an energy company headquartered in Duluth, Minn. In addition to its electric utilities, Minnesota Power and Superior Water, Light and Power of Wisconsin, ALLETE owns ALLETE Clean Energy, based in Duluth, BNI Energy in Bismarck, N.D., U.S. Water Services headquartered in St. Michael, Minn., and has an eight percent equity interest in the American Transmission Co. More information about ALLETE is available at www.allete.com . *ALE-CORP*

The statements contained in this release and statements that ALLETE may make orally in connection with this release that are not historical facts, are forward-looking statements. Actual results may differ materially from those projected in the forward-looking statements. These forward-looking statements involve risks and uncertainties and investors are directed to the risks discussed in documents filed by ALLETE with the Securities and Exchange Commission.

ALLETE's press releases and other communications may include certain non-Generally Accepted Accounting Principles (GAAP) financial measures. A "non-GAAP financial measure" is defined as a numerical measure of a company's financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP in the company's financial statements.

Non-GAAP financial measures utilized by the Company may include presentations of earnings (loss) per share and earnings before interest, taxes, depreciation and amortization. ALLETE's management believes that these non-GAAP financial measures provide useful information to investors by removing the effect of variances in GAAP reported results of operations that are not indicative of changes in the fundamental earnings power of the Company's operations. Management believes that the presentation of the non-GAAP financial measures is appropriate and enables investors and analysts to more accurately compare the company's ongoing financial performance over the periods presented.

ALLETE, Inc.
Consolidated Statement of Income
For the Periods Ended December 31, 2017 and 2016

	Quarter Ended		Year to Date	
	2017	**2016**	**2017**	**2016**
Millions Except Per Share Amounts				
Operating Revenue				
Utility	$239.7	$260.2	$1,063.8	$1,000.7
Non-utility	98.2	81.3	355.5	339.0
Total Operating Revenue	337.9	341.5	1,419.3	1,339.7
Operating Expenses				
Fuel, Purchased Power and Gas – Utility	113.7	89.3	396.9	339.9
Transmission Services – Utility	18.1	15.7	71.2	65.2
Cost of Sales – Non-utility	41.7	29.2	147.8	137.7
Operating and Maintenance	91.7	93.2	339.9	334.1
Depreciation and Amortization	26.0	50.1	177.5	195.8
Taxes Other than Income Taxes	14.2	13.2	56.9	53.8
Other	(0.7)	(10.3)	(0.7)	(10.3)
Total Operating Expenses	304.7	280.4	1,189.5	1,116.2
Operating Income	33.2	61.1	229.8	223.5
Other Income (Expense)				
Interest Expense	(17.3)	(17.3)	(67.8)	(70.3)
Equity Earnings in ATC	5.2	3.5	22.5	18.5
Other	0.4	1.1	2.4	3.9
Total Other Expense	(11.7)	(12.7)	(42.9)	(47.9)
Income Before Non-Controlling Interest and Income Taxes	21.5	48.4	186.9	175.6
Income Tax Expense (Benefit)	(19.9)	4.1	14.7	19.8
Net Income	41.4	44.3	172.2	155.8
Less: Non-Controlling Interest in Subsidiaries	—	—	—	0.5
Net Income Attributable to ALLETE	$41.4	$44.3	$172.2	$155.3
Average Shares of Common Stock				
Basic	51.1	49.5	50.8	49.3
Diluted	51.3	49.7	51.0	49.5
Basic Earnings Per Share of Common Stock	$0.81	$0.89	$3.39	$3.15
Diluted Earnings Per Share of Common Stock	$0.81	$0.89	$3.38	$3.14
Dividends Per Share of Common Stock	$0.535	$0.52	$2.14	$2.08

Consolidated Balance Sheet
Millions

	Dec. 31, 2017	**Dec. 31, 2016**		**Dec. 31, 2017**	**Dec. 31, 2016**
Assets			**Liabilities and Equity**		
Cash and Cash Equivalents	$98.9	$27.5	Current Liabilities	$351.2	$399.5
Other Current Assets	268.6	267.0	Long-Term Debt	1,439.2	1,370.4
Property, Plant and Equipment – Net	3,822.4	3,741.2	Deferred Income Taxes	230.5	554.6
Regulatory Assets	384.7	330.1	Regulatory Liabilities	532.0	125.8
Investment in ATC	118.7	135.6	Defined Benefit Pension & Other Postretirement Benefit Plans	191.8	210.9
Other Investments	53.1	55.6	Other Non-Current Liabilities	267.1	322.7
Goodwill and Intangibles – Net	225.9	213.4	Equity	2,068.2	1,893.0
Other Non-Current Assets	107.7	106.5			
Total Assets	$5,080.0	$4,876.9	**Total Liabilities and Equity**	$5,080.0	$4,876.9

ALLETE, Inc. Income (Loss)	Quarter Ended December 31, 2017	2016	Year to Date December 31, 2017	2016
Millions				
Regulated Operations	$18.3	$25.5	$128.4	$135.5
Energy Infrastructure and Related Services				
ALLETE Clean Energy	30.4	3.7	41.5	13.4
U.S. Water Services	9.1	(0.5)	10.7	1.5
Corporate and Other	(16.4)	15.6	(8.4)	4.9
Net Income Attributable to ALLETE	$41.4	$44.3	$172.2	$155.3
Diluted Earnings Per Share	$0.81	$0.89	$3.38	$3.14

Statistical Data				
Corporate				
Common Stock				
High	$81.24	$66.92	$81.24	$66.92
Low	$72.96	$56.48	$61.64	$48.26
Close	$74.36	$64.19	$74.36	$64.19
Book Value	$40.46	$38.17	$40.46	$38.17

Kilowatt-hours Sold				
Millions				
Regulated Utility				
Retail and Municipal				
Residential	305	286	1,096	1,102
Commercial	359	352	1,420	1,442
Municipal	208	205	799	816
Industrial	1,890	1,716	7,327	6,456
Total Retail and Municipal	2,762	2,559	10,642	9,816
Other Power Suppliers	1,017	860	4,039	4,316
Total Regulated Utility	3,779	3,419	14,681	14,132

Regulated Utility Revenue				
Millions				
Regulated Operations				
Retail and Municipal				
Residential	$33.5	$30.6	$119.9	$115.8
Commercial	35.6	33.6	139.5	133.7
Municipal	12.8	17.2	57.9	67.6
Industrial	123.7	110.0	486.5	412.5
Reserve for Interim Rate Refunds	(31.6)	—	(31.6)	—
Total Retail and Municipal	174.0	191.4	772.2	729.6
Other Power Suppliers	37.8	41.9	161.8	175.1
Other	27.9	26.9	129.8	96.0
Total Regulated Utility Revenue	$239.7	$260.2	$1,063.8	$1,000.7

This exhibit has been furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, except as shall be expressly set forth by specific reference in such filing.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2017

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____

Commission File Number: 1-12579

OGE ENERGY CORP.

(Exact name of registrant as specified in its charter)

Oklahoma	**73-1481638**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

321 North Harvey
P.O. Box 321
Oklahoma City, Oklahoma 73101-0321
(Address of principal executive offices)
(Zip Code)

Registrant's telephone number, including area code: **405-553-3000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
☑ Yes ☐ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
☐ Yes ☑ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☑ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☑ Yes ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐
	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐ Yes ☑ No

At June 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of shares of common stock held by non-affiliates was $6,947,712,180 based on the number of shares held by non-affiliates (199,704,288) and the reported closing market price of the common stock on the New York Stock Exchange on such date of $34.79.

At January 31, 2018, there were 199,706,104 shares of common stock, par value $0.01 per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The Proxy Statement for the Company's 2018 annual meeting of shareowners is incorporated by reference into Part III of this Form 10-K.

OGE ENERGY CORP.

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2017

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GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations that are found throughout this Form 10-K.

Abbreviation	Definition
2017 Tax Act	Tax Cuts and Jobs Act of 2017
401(k) Plan	Qualified defined contribution retirement plan
ALJ	Administrative Law Judge
APSC	Arkansas Public Service Commission
ArcLight group	Bronco Midstream Holdings, LLC and Bronco Midstream Holdings II, LLC, collectively
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
AVEC	Arkansas Valley Electric Cooperative Corporation
Bbl/d	Barrels per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Btu	British thermal unit
CSAPR	Cross-State Air Pollution Rule
CenterPoint	CenterPoint Energy Resources Corp., wholly-owned subsidiary of CenterPoint Energy, Inc.
CO_2	Carbon dioxide
Code	Internal Revenue Code of 1986
Company	OGE Energy, collectively with its subsidiaries
Dry Scrubbers	Dry flue gas desulfurization units with spray dryer absorber
Dth/d	Dekatherm per day
ECP	Environmental Compliance Plan
EGT	Enable Gas Transmission, LLC, a wholly-owned subsidiary of Enable that operates a 5,900-mile interstate pipeline that provides natural gas transportation and storage services to customers principally in the Anadarko, Arkoma and Ark-La-Tex basins in Oklahoma, Texas, Arkansas, Louisiana and Kansas
Enable	Enable Midstream Partners, LP, partnership between OGE Energy, the ArcLight group and CenterPoint Energy, Inc. formed to own and operate the midstream businesses of OGE Energy and CenterPoint
Enogex Holdings	Enogex Holdings LLC, the parent company of Enogex LLC and a majority-owned subsidiary of OGE Holdings, LLC (prior to May 1, 2013)
Enogex LLC	Enogex LLC, collectively with its subsidiaries (effective June 30, 2013, the name was changed to Enable Oklahoma Intrastate Transmission, LLC)
EOIT	Enable Oklahoma Intrastate Transmission, LLC formerly Enogex LLC, a wholly-owned subsidiary of Enable that operates a 2,200-mile intrastate pipeline that provides natural gas transportation and storage services to customers in Oklahoma
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
Federal Clean Water Act	Federal Water Pollution Control Act of 1972, as amended
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
GAAP	Accounting principles generally accepted in the U.S.
IRP	Integrated Resource Plan
kV	Kilovolt
LDC	Local distribution company involved in the delivery of natural gas to consumers within a specific geographic area
MATS	Mercury and Air Toxics Standards
MBbl/d	Thousand barrels per day
MMBtu	Million British thermal unit
MMcf/d	Million cubic feet per day
MRT	Enable Mississippi River Transmission, LLC, a wholly owned subsidiary of Enable that operates a 1,700-mile interstate pipeline that provides natural gas transportation and storage services principally in Texas, Arkansas, Louisiana, Missouri and Illinois
Mustang Modernization Plan	The construction of seven new, efficient combustion turbines with generating capability of 462 MWs
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation

NGL	Natural gas liquid
NO_X	Nitrogen oxide
OCC	Oklahoma Corporation Commission
OG&E	Oklahoma Gas and Electric Company, wholly-owned subsidiary of OGE Energy
OGE Holdings	OGE Enogex Holdings LLC, wholly-owned subsidiary of OGE Energy, parent company of Enogex Holdings and 25.7 percent owner of Enable Midstream Partners
OSHA	Federal Occupational Safety and Health Act of 1970
Pension Plan	Qualified defined benefit retirement plan
Ppb	Parts per billion
QF	Qualified cogeneration facility
QF contracts	Contracts with QFs and small power production producers
Regional Haze Rule	The EPA's Regional Haze Rule
Restoration of Retirement Income Plan	Supplemental retirement plan to the Pension Plan
SESH	Southeast Supply Header, LLC
SIP	State Implementation Plan
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
Stock Incentive Plan	2013 Stock Incentive Plan
System sales	Sales to OG&E's customers
TBtu/d	Trillion British thermal units per day
U.S.	United States of America

FORWARD-LOOKING STATEMENTS

Except for the historical statements contained herein, the matters discussed in this Form 10-K, including those matters discussed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "objective," "plan," "possible," "potential," "project" and similar expressions. Actual results may vary materially from those expressed in forward-looking statements. In addition to the specific risk factors discussed in "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" herein, factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- general economic conditions, including the availability of credit, access to existing lines of credit, access to the commercial paper markets, actions of rating agencies and their impact on capital expenditures;
- the ability of the Company and its subsidiaries to access the capital markets and obtain financing on favorable terms as well as inflation rates and monetary fluctuations;
- the ability to obtain timely and sufficient rate relief to allow for recovery of items such as capital expenditures, fuel costs, operating costs, transmission costs and deferred expenditures;
- prices and availability of electricity, coal, natural gas and NGLs;
- the timing and extent of changes in commodity prices, particularly natural gas and NGLs, the competitive effects of the available pipeline capacity in the regions Enable serves and the effects of geographic and seasonal commodity price differentials, including the effects of these circumstances on re-contracting available capacity on Enable's interstate pipelines;
- the timing and extent of changes in the supply of natural gas, particularly supplies available for gathering by Enable's gathering and processing business and transporting by Enable's interstate pipelines, including the impact of natural gas and NGLs prices on the level of drilling and production activities in the regions Enable serves;
- business conditions in the energy and natural gas midstream industries, including the demand for natural gas, NGLs, crude oil and midstream services;
- competitive factors including the extent and timing of the entry of additional competition in the markets served by the Company;
- the impact on demand for our services resulting from cost-competitive advances in technology, such as distributed electricity generation and customer energy efficiency programs;
- technological developments, changing markets and other factors that result in competitive disadvantages and create the potential for impairment of existing assets;
- factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, unusual maintenance or repairs; unanticipated changes to fossil fuel, natural gas or coal supply costs or availability due to higher demand, shortages, transportation problems or other developments; environmental incidents; or electric transmission or gas pipeline system constraints;
- availability and prices of raw materials for current and future construction projects;
- the effect of retroactive pricing of transactions in the SPP markets or adjustments in market pricing mechanisms by the SPP;
- federal or state legislation and regulatory decisions and initiatives that affect cost and investment recovery have an impact on rate structures or affect the speed and degree to which competition enters the Company's markets;
- environmental laws, safety laws or other regulations that may impact the cost of operations or restrict or change the way the Company operates its facilities;
- changes in accounting standards, rules or guidelines;
- the discontinuance of accounting principles for certain types of rate-regulated activities;
- the cost of protecting assets against, or damage due to, terrorism or cyberattacks and other catastrophic events;
- creditworthiness of suppliers, customers and other contractual parties;
- social attitudes regarding the utility, natural gas and power industries;
- identification of suitable investment opportunities to enhance shareholder returns and achieve long-term financial objectives through business acquisitions and divestitures;
- increased pension and healthcare costs;
- costs and other effects of legal and administrative proceedings, settlements, investigations, claims and matters, including, but not limited to, those described in this Form 10-K;
- difficulty in making accurate assumptions and projections regarding future revenues and costs associated with the Company's equity investment in Enable that the Company does not control; and
- other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission, including those listed in "Item 1A. Risk Factors."

The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

PART I

Item 1. Business.

THE COMPANY

Introduction

The Company is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central U.S. The Company conducts these activities through two business segments: (i) electric utility and (ii) natural gas midstream operations. The accounts of the Company and its wholly owned subsidiaries are included in the consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation. The Company generally uses the equity method of accounting for investments where its ownership interest is between 20 percent and 50 percent and it lacks the power to direct activities that most significantly impact economic performance. The Company was incorporated in August 1995 in the State of Oklahoma and its principal executive offices are located at 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321; telephone 405-553-3000.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E and are subject to regulation by the OCC, the APSC and the FERC. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory and is a wholly owned subsidiary of the Company. OG&E is the largest electric utility in Oklahoma, and its franchised service territory includes Fort Smith, Arkansas and the surrounding communities. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

The natural gas midstream operations segment represents the Company's investment in Enable through wholly owned subsidiaries and ultimately OGE Holdings. Enable is engaged in the business of gathering, processing, transporting and storing natural gas. Enable's natural gas gathering and processing assets are strategically located in four states and serve natural gas production from shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. Enable also owns an emerging crude oil gathering business in the Bakken Shale formation, principally located in the Williston Basin of North Dakota. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

Enable was formed effective May 1, 2013 by the Company, the ArcLight group and CenterPoint to own and operate the midstream businesses of the Company and CenterPoint. In the formation transaction, the Company and the ArcLight group contributed Enogex LLC to Enable, and the Company deconsolidated its previously held investment in Enogex Holdings and acquired an equity interest in Enable. The Company determined that its contribution of Enogex LLC to Enable met the requirements of being in substance real estate and was recorded at historical cost. The general partner of Enable is equally controlled by the Company and CenterPoint, who each have 50 percent management ownership. Based on the 50/50 management ownership, with neither company having control, the Company began accounting for its interest in Enable using the equity method of accounting.

In April 2014, Enable completed an initial public offering of 25.0 million common units resulting in Enable becoming a publicly traded Master Limited Partnership. At December 31, 2017, the Company owned 111.0 million common units, or 25.7 percent, of Enable's outstanding common units. For additional information on the Company's equity investment in Enable and related party transactions, see Note 3 in "Item 8. Financial Statements and Supplementary Data."

Over the past three years, Enable has seen changes in producer activity due to the volatility of commodity prices. In early 2016, natural gas and crude oil prices dropped to their lowest levels in over 10 years. During 2016 and 2017, those prices increased, and have stabilized, but have not rebounded to the pre-2015 levels. If commodity prices decline further, Enable's future operating results and cash flows could be negatively impacted. A portion of our earnings and operating cash flows depend on the performance of, and distributions from, Enable. As disclosed in this Form 10-K, Enable is subject to a number of risks. If any of those risks were to occur, the Company's business, financial condition, results of operations or cash flows could be materially adversely affected.

On February 9, 2018, Enable announced a quarterly dividend distribution of $0.31800 per unit on its outstanding common units, which is unchanged from the previous quarter. If cash distributions to Enable’s unitholders exceed $0.330625 per unit in any quarter, the general partner will receive increasing percentages, up to 50 percent, of the cash Enable distributes in excess of that amount. The Company is entitled to 60 percent of those "incentive distributions."

Company Strategy

The Company's mission, through OG&E and its equity interest in Enable, is to fulfill its critical role in the nation's electric utility and natural gas midstream pipeline infrastructure and meet individual customer's needs for energy and related services, focusing on safety, efficiency, reliability, customer service and risk management. The Company's corporate strategy is to continue to maintain its existing business mix and diversified asset position of its regulated electric utility business and interest in a publicly traded midstream company, while providing competitive energy products and services to customers, as well as seeking growth opportunities in both businesses.

OG&E is focused on:

- providing exceptional customer experiences by continuing to improve customer interfaces, tools, products and services that deliver high customer satisfaction and operating productivity;
- providing safe, reliable energy to the communities and customers we serve, with a particular focus on enhancing the value of the grid by improving distribution grid reliability by reducing the frequency and duration of customer interruptions and leveraging previous grid technology investments;
- having strong regulatory and legislative relationships for the long-term benefit of our customers, investors and members;
- continuing to grow a zero-injury culture and deliver top-quartile safety results;
- complying with the EPA's Regional Haze Rule requirements;
- ensuring we have the necessary mix of generation resources to meet the long-term needs of our customers; and
- continuing focus on operational excellence and efficiencies in order to protect the customer bill.

Additionally, the Company wants to achieve a premium valuation of its businesses relative to its peers, grow earnings per share with a stable earnings pattern, create a high performance culture and achieve desired outcomes with target stakeholders. The Company's financial objectives include a long-term annual earnings growth rate for OG&E of three to five percent on a weather-normalized basis, maintaining a strong credit rating as well as targeting dividend increases of approximately 10 percent annually through 2019. The targeted annual dividend increase has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets and the composition of the Company's assets and investment opportunities. The Company also utilizes cash distributions from its investment in Enable to help fund its capital needs and support future dividend growth. The Company believes it can accomplish these financial objectives by, among other things, pursuing multiple avenues to build its business, maintaining a diversified asset position, continuing to develop a wide range of skills to succeed with changes in its industries, providing products and services to customers efficiently, managing risks effectively and having strong regulatory and legislative relationships.

ELECTRIC OPERATIONS - OG&E

General

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E. OG&E furnishes retail electric service in 267 communities and their contiguous rural and suburban areas. The service area covers 30,000 square miles in Oklahoma and western Arkansas, including Oklahoma City, the largest city in Oklahoma, and Fort Smith, Arkansas, the second largest city in that state. Of the 267 communities that OG&E serves, 241 are located in Oklahoma, and 26 are in Arkansas. OG&E derived 91 percent of its total electric operating revenues in 2017 from sales in Oklahoma and the remainder from sales in Arkansas. OG&E does not currently serve wholesale customers in either state.

OG&E's system control area peak demand in 2017 was 6,456 MWs on July 21, 2017. OG&E's load responsibility peak demand was 5,752 MWs on July 21, 2017. The following table shows system sales and variations in system sales for 2017, 2016 and 2015.

Year Ended December 31	**2017**	**2017 vs. 2016**	2016	2016 vs. 2015	2015
System sales - (*Millions of MWh*)	**26.3**	**(2.2)%**	26.9	(1.1)%	27.2

OG&E is subject to competition in various degrees from government-owned electric systems, municipally-owned electric systems, rural electric cooperatives and, in certain respects, from other private utilities, power marketers and cogenerators as well

as from consumers choosing appliances powered by other energy sources. Oklahoma law forbids the granting of an exclusive franchise to a utility for providing electricity.

Besides competition from other suppliers or marketers of electricity, OG&E competes with suppliers of other forms of energy. The degree of competition between suppliers may vary depending on relative costs and supplies of other forms of energy. It is possible that changes in regulatory policies or advances in technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells will reduce costs of new technology to levels that are equal to or below that of most central station electricity production. Our ability to maintain relatively low cost, efficient and reliable operations is a significant determinate of our competitiveness.

OKLAHOMA GAS AND ELECTRIC COMPANY
CERTAIN OPERATING STATISTICS

Year Ended December 31	**2017**	2016	2015
ELECTRIC ENERGY *(Millions of MWh)*			
Generation (exclusive of station use)	**18.5**	21.4	20.9
Purchased	**11.0**	9.6	9.2
Total generated and purchased	**29.5**	31.0	30.1
OG&E use, free service and losses	**(1.4)**	(1.1)	(1.2)
Electric energy sold	**28.1**	29.9	28.9
ELECTRIC ENERGY SOLD *(Millions of MWh)*			
Residential	**8.8**	9.3	9.2
Commercial	**7.6**	7.6	7.4
Industrial	**3.6**	3.6	3.6
Oilfield	**3.2**	3.2	3.4
Public authorities and street light	**3.1**	3.2	3.1
Sales for resale	**—**	—	0.5
System sales	**26.3**	26.9	27.2
Integrated market	**1.8**	3.0	1.7
Total sales	**28.1**	29.9	28.9
ELECTRIC OPERATING REVENUES *(In millions)*			
Residential	**$ 884.1**	$ 951.9	$ 896.5
Commercial	**588.3**	573.7	535.0
Industrial	**200.6**	194.6	190.6
Oilfield	**159.5**	156.9	162.8
Public authorities and street light	**208.0**	204.3	194.2
Sales for resale	**0.2**	0.3	21.7
System sales revenues	**2,040.7**	2,081.7	2,000.8
Provision for rate refund	**26.8**	(33.6)	—
Integrated market	**23.5**	49.3	48.6
Other	**170.1**	161.8	147.5
Total operating revenues	**$ 2,261.1**	$ 2,259.2	$ 2,196.9
ACTUAL NUMBER OF ELECTRIC CUSTOMERS *(At end of period)*			
Residential	**719,441**	712,467	705,294
Commercial	**96,098**	94,790	93,401
Industrial	**2,795**	2,831	2,872
Oilfield	**6,415**	6,469	6,328
Public authorities and street light	**17,081**	17,025	16,880
Sales for resale	**—**	—	1
Total customers	**841,830**	833,582	824,776
AVERAGE RESIDENTIAL CUSTOMER SALES			
Average annual revenue	**$ 1,234.92**	$ 1,342.88	$ 1,278.51
Average annual use (kilowatt-hour)	**12,324**	13,105	13,062
Average price per kilowatt-hour (cents)	**10.02**	10.25	9.79

Regulation and Rates

OG&E's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E's transmission activities, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the U.S. Department of Energy has jurisdiction over some of OG&E's facilities and operations. In 2017, 85 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and seven percent to the FERC.

The OCC issued an order in 1996 authorizing OG&E to reorganize into a subsidiary of the Company. The order required that, among other things, (i) the Company permit the OCC access to the books and records of the Company and its affiliates relating to transactions with OG&E, (ii) the Company employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers and (iii) the Company refrain from pledging OG&E assets or income for affiliate transactions. In addition, the Energy Policy Act of 2005 enacted the Public Utility Holding Company Act of 2005, which in turn granted to the FERC access to the books and records of the Company and its affiliates as the FERC deems relevant to costs incurred by OG&E or necessary or appropriate for the protection of utility customers with respect to the FERC jurisdictional rates.

Completed Regulatory Matters

Arkansas Rate Case Filing

On August 25, 2016, OG&E filed a general rate case with the APSC. The rate filing requested a $16.5 million rate increase based on a 10.25 percent return on equity. The requested rate increase was based on a June 30, 2016 test year and included recovery of over $3.0 billion of electric infrastructure additions since the last Arkansas general rate case in 2011. The requested increase also reflected increases in operation and maintenance expenses, including vegetation management and increased recovery of depreciation and dismantlement costs.

In May 2017, the APSC approved a settlement between OG&E and the staff of the APSC and other intervenors. The settlement provided for a $7.1 million annual rate increase and a 9.5 percent return on equity on a 50.0 percent equity capital structure.

The settlement also provided that OG&E will be regulated under a formula rate rider, which should result in a more efficient process as the return on equity, depreciation rates and capital structure should not change from what was approved by the APSC in this settlement. OG&E expects to make its first filing under the Arkansas Formula Rate Rider in October 2018.

Fuel Adjustment Clause Review for Calendar Year 2015

On September 8, 2016, the OCC staff filed an application to review OG&E’s fuel adjustment clause for calendar year 2015, including the prudence of OG&E’s electric generation, purchased power and fuel procurement costs. On October 12, 2017, the OCC issued an order finding that, for the calendar year 2015, OG&E's electric generation, purchased power and fuel procurement processes and costs were prudent.

Oklahoma Rate Case Filing - 2015

On December 18, 2015, OG&E filed a general rate case with the OCC requesting a rate increase of $92.5 million and a 10.25 percent return on equity based on a common equity percentage of 53.0 percent. The rate case was based on a June 30, 2015 test year and included recovery of $1.6 billion of electric infrastructure additions since its last general rate case in Oklahoma.

On July 1, 2016, OG&E implemented an annual interim rate increase of $69.5 million, subject to refund for amounts in excess of the rates approved by the OCC.

In December 2016, the ALJ issued a report and recommendations in the case. The ALJ's recommendations included, among other things, the use of OG&E's actual capital structure of 53.0 percent equity and 47.0 percent long-term debt and a return on equity of 9.87 percent resulting in an annual increase in OG&E's revenues of $40.7 million.

During February and March 2017, the OCC held hearings and, on March 20, 2017, issued an order. The order resulted in an annual net increase of approximately $8.8 million in OG&E's rates to its Oklahoma retail customers. Although the order adopted certain recommendations set forth in the ALJ report, it differed in certain key respects.

The primary adjustments to the ALJ report consist of: (i) Oklahoma retail authorized rate of return on equity of 9.50 percent, (ii) depreciation expense is reduced by approximately $28.6 million from the ALJ report or $36.4 million from then current rates on an annual basis, (iii) recovery of 50.0 percent of short-term incentive compensation and no recovery of long-term incentive compensation, (iv) recovery of OG&E's requested vegetation management expenses and (v) recovery of production tax credits expiring in 2017 and air quality control systems consumable costs through the fuel adjustment clause. The order maintained OG&E's existing capital structure of 53.0 percent equity and 47.0 percent long-term debt.

As a result of the March 2017 OCC rate order, OG&E recorded, in the first quarter of 2017, adjustments to depreciation expense, amortization of regulatory assets and liabilities and impacts to the fuel adjustment clause effective July 1, 2016. On May 1, 2017, OG&E implemented new rates and began refunding excess amounts that it had collected in interim rates.

As of November 30, 2017, OG&E had completed the refund of $47.5 million collected in excess interim rates.

Mustang Modernization Plan - Arkansas

On August 15, 2017, OG&E filed for a determination with the APSC that the Mustang facility is in the public interest. The filing did not seek recovery for any costs associated with the Mustang Modernization Plan, as request for recovery of costs will take place with the first formula rate filing expected to be made in October 2018. On January 2, 2018, the APSC issued an order finding the Mustang Modernization Plan to be in the public interest.

Pending Regulatory Matters

Set forth below is a list of various proceedings pending before state or federal regulatory agencies. Unless stated otherwise, OG&E cannot predict when the regulatory agency will act or what action the regulatory agency will take. OG&E's financial results are dependent in part on timely and adequate decisions by the regulatory agencies that set OG&E's rates.

Environmental Compliance Plan

On August 6, 2014, OG&E filed an application with the OCC for approval of its plan to comply with the EPA's MATS and Regional Haze Rule FIP while serving the best long-term interests of customers in light of future environmental uncertainties. The application sought approval of the ECP and for a recovery mechanism for the associated costs. The ECP includes installing Dry Scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas. The application also asked the OCC to predetermine the prudence of its Mustang Modernization Plan and approval for a recovery mechanism for the associated costs.

On December 2, 2015, OG&E received an order from the OCC denying its plan to comply with the environmental mandates of the Federal Clean Air Act, Regional Haze Rule and MATS. The OCC also denied OG&E's request for pre-approval of its Mustang Modernization Plan, revised depreciation rates for both the retirement of the Mustang units and the replacement combustion turbines and pre-approval of early retirement and replacement of generating units at its Mustang site, including cost recovery through a rider.

On February 12, 2016, OG&E filed an application requesting the OCC to issue an order approving its decision to install Dry Scrubbers at the Sooner facility. OG&E's application did not seek approval of the costs of the Dry Scrubber project. Instead, the reasonableness of the costs would be considered after the project is completed, and OG&E seeks recovery in a general rate case. On April 28, 2016, the OCC approved the Dry Scrubber project.

Two parties appealed the OCC's decision to the Oklahoma Supreme Court. The Company is unable to predict what action the Oklahoma Supreme Court may take or the timing of any such action.

OG&E anticipates the total cost of Dry Scrubbers will be $542.4 million, including allowance for funds used during construction and capitalized ad valorem taxes and expects the project to be completed in mid to late 2018. As of December 31, 2017, OG&E had invested $401.3 million in the Dry Scrubbers. OG&E anticipates the total cost for the Mustang Modernization Plan will be $390.0 million, including allowance for funds used during construction and capitalized ad valorem taxes and expects the project to be completed in early 2018. As of December 31, 2017, OG&E had invested $348.4 million in the Mustang Modernization Plan.

Integrated Resource Plans

In October 2015, OG&E finalized the 2015 IRP and submitted it to the OCC. The 2015 IRP updated certain assumptions contained in the IRP submitted in 2014 but did not make any material changes to the ECP and other parts of the plan. Currently, OG&E is scheduled to update its IRP in Oklahoma by October 1, 2018 and in Arkansas by October 31, 2018.

Demand Program Rider - Energy Efficiency Lost Net Revenues

During the May 2017 implementation of new rates, OG&E reserved $5.6 million, pending resolution of a dispute with the OCC's Public Utility Division staff, regarding recovery of certain lost revenues associated with energy efficiency incurred prior to the March 2017 OCC rate order. These lost revenues are included within the total Demand Program Rider regulatory asset balance of $31.6 million as disclosed in Note 1 in "Item 8. Financial Statements and Supplementary Data."

Fuel Adjustment Clause Review for Calendar Year 2016

On August 3, 2017, the OCC staff filed an application to review OG&E's fuel adjustment clause for calendar year 2016, including the prudence of OG&E's electric generation, purchased power and fuel procurement costs. On February 7, 2018, an intervenor filed a recommendation to disallow the Oklahoma jurisdictional portion of $3.3 million related to wind sales in the SPP. A hearing is scheduled for March 29, 2018.

Oklahoma Rate Case Filing - 2018

On January 16, 2018, OG&E filed a general rate case in Oklahoma, requesting a rate increase of $1.9 million per year, assuming a 9.9 percent return on equity. The filing seeks recovery of the seven Mustang combustion turbines that are part of the Mustang Modernization Plan, requests an increase in depreciation rates to levels similar with rates in existence prior to the March 2017 OCC rate order and credits customers for the impacts of the 2017 Tax Act, enacted on December 22, 2017.

On December 22, 2017, the Attorney General of Oklahoma requested that the OCC reduce the rates and charges for electric service and provide for any refund due to the customers of OG&E resulting from the 2017 Tax Act. In response, on January 4, 2018, the OCC ordered OG&E to record a reserve, beginning on January 4, 2018, to reflect the reduced federal corporate tax rate of 21 percent and the amortization of excess accumulated deferred income tax and any other tax implications of the 2017 Tax Act on an interim basis, subject to refund until utility rates are adjusted to reflect the federal tax savings and a final order is issued in OG&E's pending rate case filed on January 16, 2018. Further, the OCC ordered the amounts of any refunds of such reserves owed to customers should accrue interest at a rate equivalent to OG&E's cost of capital as previously recognized in the March 2017 OCC rate order.

APSC Order - 2017 Tax Act

On January 12, 2018, as a result of the 2017 Tax Act, the APSC ordered OG&E to prepare and file an analysis, within 30 days of this order, of the ratemaking effects of the 2017 Tax Act on OG&E's revenue requirement and begin, effective January 1, 2018, to book regulatory liabilities to record the current and deferred impacts of the 2017 Tax Act. The APSC will subsequently solicit comments or testimony regarding the extent of the impacts of the 2017 Tax Act and how any resulting benefits, including carrying charges, should be returned to customers.

FERC - Section 206 Filing

In January 2018, the Oklahoma Municipal Power Authority filed a complaint at the FERC stating that the base return on common equity used by OG&E in calculating formula transmission rates under the SPP Open Access Transmission Tariff is unjust and unreasonable and should be reduced from 10.60 percent to 7.85 percent, effective upon the date of the complaint. The Company is analyzing the potential impact of the complaint but estimates that if the FERC ultimately orders a reduction, each 25 basis point reduction in the requested return on equity would reduce the Company's SPP Open Access Transmission Tariff transmission revenues by approximately $1.5 million annually. In addition to the request to reduce the return on equity, the Oklahoma Municipal Power Authority's complaint also requests that modifications be made to OG&E's transmission formula rates to reflect the impacts of the 2017 Tax Act. Although the proceeding is in the early stages, OG&E expects to contest the reduction of its base return on equity. The Company is unable to predict what action the FERC will take in response to the Oklahoma Municipal Power Authority's complaint or the timing of such action. However, if the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could have a material adverse effect on the Company's consolidated financial position, results of operations and cash flows.

Regulatory Assets and Liabilities

OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide that certain incurred costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

OG&E records certain incurred costs and obligations as regulatory assets or liabilities if, based on regulatory orders or other available evidence, it is probable that the costs or obligations will be included in amounts allowable for recovery or refund in future rates.

At December 31, 2017 and 2016, OG&E had regulatory assets of $323.8 million and $526.6 million, respectively, and regulatory liabilities of $1,287.3 million and $312.0 million, respectively. These amounts include additional regulatory assets and liabilities for OG&E resulting from the reduction in the corporate federal tax rate enacted by the 2017 Tax Act. See Note 1 and Note 7 in "Item 8. Financial Statements and Supplementary Data" for further discussion.

Management continuously monitors the future recoverability of regulatory assets. When, in management's judgment, future recovery becomes impaired, the amount of the regulatory asset is adjusted, as appropriate. If OG&E were required to discontinue the application of accounting principles for certain types of rate-regulated activities for some or all of its operations, it could result in writing off the related regulatory assets, which could have significant financial effects.

Rate Structures

Oklahoma

OG&E's standard tariff rates include a cost of service component (including an authorized return on capital) plus a fuel adjustment clause mechanism that allows OG&E to pass through to customers the actual cost of fuel and purchased power.

OG&E offers several alternative customer programs and rate options. Under OG&E's Smart Grid-enabled SmartHours programs, "time-of-use" and "variable peak pricing" rates offer customers the ability to save on their electricity bills by shifting some of the electricity consumption to off-peak times when demand for electricity and costs are at their lowest. The guaranteed flat bill option for residential and small general service accounts allows qualifying customers the opportunity to purchase their electricity needs at a set monthly price for an entire year. Another tariff rate option provides a "renewable energy" resource to OG&E's Oklahoma retail customers. This renewable energy resource is a Renewable Energy Credit purchase program and is available as a voluntary option to all of OG&E's Oklahoma retail customers. OG&E's ownership and access to wind and solar resources makes the renewable option a possible choice in meeting the renewable energy needs of our conservation-minded customers. Another program being offered to OG&E's commercial and industrial customers is a voluntary load curtailment program called Load Reduction. This program provides customers with the opportunity to curtail usage on a voluntary basis when OG&E's system conditions merit curtailment action. Customers that curtail their usage will receive payment for their curtailment response. This voluntary curtailment program seeks customers that can curtail on most curtailment event days but may not be able to curtail every time that a curtailment event is required. OG&E also offers certain qualifying customers "day-ahead price" and "flex price" rate options which allow participating customers to adjust their electricity consumption based on price signals received from OG&E. The prices for the "day-ahead price" and "flex price" rate options are based on OG&E's projected next day hourly operating costs.

OG&E has Public Schools-Demand and Public Schools Non-Demand rate classes that provide OG&E with flexibility to provide targeted programs for load management to public schools and their unique usage patterns. OG&E also provides service level, seasonal and time period fuel charge differentiation that allows customers to pay fuel costs that better reflect the underlying costs of providing electric service. Lastly, OG&E has a military base rider that demonstrates Oklahoma's continued commitment to our military partners.

The previously discussed rate options, coupled with OG&E's other rate choices, provide many tariff options for OG&E's Oklahoma retail customers. The revenue impacts associated with these options are not determinable in future years because customers may choose to remain on existing rate options instead of volunteering for the alternative rate option choices. Revenue variations may occur in the future based upon changes in customers' usage characteristics if they choose alternative rate options.

Arkansas

OG&E's standard tariff rates include a cost of service component (including an authorized return on capital) plus an energy cost recovery mechanism that allows OG&E to pass through to customers the actual cost of fuel and purchased power. In May 2017, the APSC approved a settlement requiring OG&E to be regulated under a formula rate rider. The formula rate rider provides for an adjustment to rates approved by the APSC in the May 2017 settlement if the earned rate of return falls outside of a plus or minus 50 basis point dead-band around the allowed return on equity. Adjustments are limited to plus or minus four percent of revenue for each rate class for the 12 months preceding the projected year. The initial term for the formula rate rider is not to exceed five years, unless additional approval is obtained from the APSC.

OG&E offers several alternative customer programs and rate options. The "time-of-use" and "variable peak pricing" tariffs allow participating customers to save on their electricity bills by shifting some of the electricity consumption to off-peak times when demand for electricity is lowest. A second tariff rate option provides a "renewable energy" resource to OG&E's Arkansas retail customers. This renewable energy resource is a Renewable Energy Credit purchase program and is available as a voluntary option to all of OG&E's Arkansas retail customers. OG&E's ownership and access to wind resources makes the renewable option a possible choice in meeting the renewable energy needs of our conservation-minded customers. OG&E offers its commercial and industrial customers a voluntary load curtailment program called Load Reduction. This program provides customers with the opportunity to curtail usage on a voluntary basis and receive a billing credit when OG&E's system conditions merit curtailment action. OG&E offers certain qualifying customers a "day-ahead price" rate option which allows participating customers to adjust their electricity consumption based on a price signal received from OG&E. The "day-ahead price" is based on OG&E's projected next day hourly operating costs.

Fuel Supply and Generation

In 2017, 54.0 percent of OG&E-generated energy was produced by coal-fired units, 39.0 percent by natural gas-fired units and seven percent by wind-powered units. Of OG&E's 6,304 total MWs of generation capability reflected in the table in "Item 2. Properties," 3,304 MWs, or 52.4 percent, are from natural gas generation, 2,548 MWs, or 40.4 percent, are from coal generation, 449 MWs, or 7.1 percent, are from wind generation and 3 MWs, or 0.1 percent, are from solar generation. Over the last five years, the weighted average cost of fuel used, by type, was as follows:

Year Ended December 31 *(In cents/Kilowatt-Hour)*	**2017**	2016	2015	2014	2013
Natural gas	**2.821**	2.488	2.529	4.506	3.905
Coal	**2.069**	2.213	2.187	2.152	2.273
Total fuel	**2.211**	2.199	2.196	2.752	2.784

The increase in the weighted average cost of fuel in 2017 compared to 2016 was primarily due to higher natural gas prices. The increase in the weighted average cost of fuel in 2016 as compared to 2015 was primarily due to higher coal prices. The decrease in the weighted average cost of fuel in 2015 as compared to 2014 was primarily due to lower natural gas prices. The decrease in the weighted average cost of fuel in 2014 as compared to 2013 was primarily due to less natural gas used, partially offset by higher natural gas prices. These fuel costs are recovered through OG&E's fuel adjustment clauses that are approved by the OCC, the APSC and the FERC.

OG&E participates in the SPP Integrated Marketplace. As part of the Integrated Marketplace, the SPP has balancing authority responsibilities for its market participants. The SPP Integrated Marketplace functions as a centralized dispatch, where market participants, including OG&E, submit offers to sell power to the SPP from their resources and bid to purchase power from the SPP for their customers. The SPP Integrated Marketplace is intended to allow the SPP to optimize supply offers and demand bids based upon reliability and economic considerations and to determine which generating units will run at any given time for maximum cost-effectiveness. As a result, OG&E's generating units produce output that is different from OG&E's customer load requirements. Net fuel and purchased power costs are recovered through fuel adjustment clauses.

Coal

OG&E's coal-fired units, with an aggregate capability of 2,548 MWs, are designed to burn low sulfur western sub-bituminous coal. The combination of all 2017 coal had a weighted average sulfur content of 0.23 percent. Based on the average sulfur content and EPA-certified data, OG&E's coal units have an approximate emission rate of 0.5 lbs. of SO_2 per MMBtu.

For 2018, OG&E has acquired approximately half of its forecasted annual coal usage via existing inventory and purchase contracts that expire in December 2019. In 2017, OG&E purchased 6.7 million tons of coal from various Wyoming suppliers. See "Environmental Laws and Regulations" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of environmental matters which may affect OG&E in the future, including its utilization of coal.

Natural Gas

As a participant in the SPP Integrated Marketplace, OG&E now purchases a relatively small percentage of its natural gas supply through long-term agreements. Alternatively, OG&E relies on a combination of natural gas call agreements, whereby OG&E has the right but not the obligation to purchase a defined quantity of natural gas, combined with day and intra-day purchases to meet the demands of the SPP Integrated Marketplace.

Wind

OG&E owns the 120 MW Centennial, 101 MW OU Spirit and 228 MW Crossroads wind farms. OG&E's current wind power portfolio also includes purchase power contracts with the following:

Company	Location	Term of Contract	Expiration of Contract	MWs
CPV Keenan	Woodward County, OK	20 years	2030	152.0
Edison Mission Energy	Dewey County, OK	20 years	2031	130.0
NextEra Energy	Blackwell, OK	20 years	2032	60.0
FPL Energy	Woodward, OK	15 years	2018	50.0

Solar

In 2015, OG&E placed its first solar plant in service. The plant consists of two separate solar farms and is located in Oklahoma City, on the site of the Mustang generating facility. The Mustang solar plant has a maximum capacity of 2.5 MWs and consists of almost 10,000 photovoltaic panels.

OG&E began construction on a new 10 MW solar farm in 2017. As of December 31, 2017, OG&E had invested $17.9 million and expects the Covington, Oklahoma solar farm to be placed in service during the first quarter of 2018. OG&E will evaluate the need to build additional solar plants based on customer demand, cost and reliability.

Safety and Health Regulation

OG&E is subject to a number of federal and state laws and regulations, including OSHA, the EPA and comparable state statutes, whose purpose is to protect the safety and health of workers.

In addition, the OSHA Hazard Communication Standard, the EPA Emergency Planning and Community Right-to-Know regulations under Title III of the Federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials stored, used or produced in OG&E's operations and that this information be provided or made available to employees, state and local government authorities and citizens. OG&E believes that it is in material compliance with all applicable laws and regulations relating to worker safety and health.

NATURAL GAS MIDSTREAM OPERATIONS - ENABLE MIDSTREAM PARTNERS

Overview

Enable is a publicly traded Delaware limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. Enable serves current and emerging production areas in the U.S., including several unconventional shale resource plays and local and regional end-user markets in the U.S. Enable's assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage. Enable's gathering and processing segment primarily provides natural gas and crude oil gathering and natural gas processing services to its producer customers. Enable's transportation and storage segment provides interstate and intrastate natural gas pipeline transportation and storage services primarily to its producer, power plant, LDC and industrial end-user customers.

Enable's natural gas gathering and processing assets are primarily located in Oklahoma, Texas, Arkansas and Louisiana and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex Basins. Enable's crude oil gathering assets are located

in North Dakota and serve crude oil production in the Bakken Shale formation of the Williston Basin. Enable's natural gas transportation and storage assets consist primarily of an interstate pipeline system extending from western Oklahoma and the Texas Panhandle to Louisiana, an interstate pipeline system extending from Louisiana to Illinois, an intrastate pipeline system in Oklahoma and an investment in SESH, a pipeline extending from Louisiana to Alabama.

Enable was formed on May 1, 2013 to own and operate the midstream businesses of the Company and CenterPoint. As of December 31, 2017, Enable's portfolio of midstream energy infrastructure assets included approximately 13,300 miles of natural gas and crude oil gathering pipelines, 15 major processing plants with 2.6 Bcf/d of processing capacity, approximately 7,800 miles of interstate pipelines (including SESH), approximately 2,200 miles of intrastate pipelines and eight natural gas storage facilities with 86.0 Bcf of storage capacity.

The following table shows the components of Enable's gross margin for the year ended December 31, 2017.

	Fee-Based			
	Demand/Commitment/Guaranteed Return	Volume Dependent	Commodity-Based	Total
Year Ended December 31, 2017				
Gathering and processing segment	27%	46%	27%	100%
Transportation and storage segment	88%	8%	4%	100%
Partnership weighted average	50%	32%	18%	100%

Gathering and Processing

Enable owns and operates substantial natural gas and crude oil gathering and natural gas processing assets in five states. Enable's gathering and processing operations consist primarily of natural gas gathering and processing assets serving the Anadarko, Arkoma and Ark-La-Tex Basins and crude oil gathering assets serving the Williston Basin. Enable provides a variety of services to the active producers in its operating areas, including gathering, compressing, treating, and processing natural gas, fractionating NGLs and gathering crude oil and produced water.

Natural Gas Gathering and Processing. The following table sets forth certain information regarding Enable's natural gas gathering and processing assets as of or for the year ended December 31, 2017:

Asset/Basin	Approximate Length (Miles)	Approximate Compression (Horsepower)	Average Gathered Volume (TBtu/d)	Number of Processing Plants	Processing Capacity (MMcf/d)	NGLs Produced (MBbl/d)
Anadarko Basin	8,200	758,000	1.81	11	1,845	76.37
Arkoma Basin	3,000	133,500	0.55	1	60	4.79
Ark-La-Tex Basin[(A)]	1,800	160,200	1.20	3	645	8.95
Total	13,000	1,051,700	3.56	15	2,550	90.11

(A) Ark-La-Tex Basin assets also include 14,500 Bbl/d of fractionation capacity and 6,300 Bbl/d of ethane pipeline capacity, which are not listed in the table.

Enable's natural gas gathering assets include approximately 13,000 miles of natural gas gathering pipelines as of December 31, 2017. Enable's natural gas gathering systems consist of networks of pipelines that collect natural gas from points at or near its customers' wells for delivery to plants for processing or pipelines for transportation. Natural gas is moved from the receipt points to the delivery points on Enable's gathering systems by the use of compression.

Enable's natural gas processing assets included 15 natural gas processing plants with 2,550 MMcf/d of inlet capacity as of December 31, 2017. Natural gas is comprised primarily of methane, but, at the wellhead, natural gas may contain varying amounts of NGLs. Enable's processing plants recover NGLs from natural gas and primarily deliver NGLs and natural gas to pipelines for transportation.

Crude Oil Gathering. As of December 31, 2017, Enable had approximately 175 miles of crude oil gathering pipelines and approximately 160 miles of produced water gathering pipelines in the Bakken Shale of the Williston Basin. Enable's crude

oil gathering systems have a combined design capacity of 57.9 MBbl/d, and as of December 31, 2017, Enable had 0.2 million gross acres dedicated under a crude oil gathering agreement. For the year ended December 31, 2017, Enable had an average daily throughput of 25.56 MBbl/d of crude oil and an average daily throughput of 9.7 MBbl/d of produced water on Enable's Williston Basin gathering system.

Enable's Williston Basin crude oil gathering assets are located in Dunn, McKenzie, Williams and Mountrail Counties in North Dakota. These systems were designed and built to serve the crude oil production of XTO Energy, Inc. in these areas. On Enable's systems, crude oil is received on crude oil gathering pipelines near its customers' wells for delivery to third party transportation pipelines, and produced water is received by produced water gathering pipelines for delivery to third party disposal wells. Enable does not take title to crude oil or produced water gathered, and it does not own or operate produced water disposal wells.

Delivery Points. Natural gas that is gathered, and when applicable, processed, is typically redelivered to Enable's customers at interconnections with transportation pipelines. Enable's gathering lines interconnect with both its interstate and intrastate pipelines, as well as other interstate and intrastate pipelines, including the Acadian, ANR, ETC Tiger, Gulf Crossing, Gulf South, NGPL, Northern Natural, Panhandle Eastern, Regency, Southern Natural Gas, Tennessee Gas and Texas Eastern Transmission pipelines. These connections provide producers with access to a variety of natural gas market hubs.

Crude oil gathered on Enable's Williston Basin gathering systems in Dunn and McKenzie Counties can be redelivered to Enable's customers through interconnections to the BakkenLink Pipeline and the Dakota Access Pipeline. Crude oil gathered on Enable's Williston Basin gathering systems in Williams and Mountrail Counties can be redelivered to Enable's customers through interconnections to the Enbridge North Dakota Pipeline and the Dakota Access Pipeline.

Enable typically purchases the NGLs produced at its processing plants, and most of the NGLs are delivered into third-party pipelines and transported to Conway, Kansas or Mont Belvieu, Texas, where the NGLs are exchanged for fractionated NGLs that are sold under contract or on the spot market. At Enable's Cox City, Calumet and Wetumka plants, Enable operates depropanizers that allow it to extract propane from the NGL stream and sell propane to local markets. Additionally, Enable operates a fractionator at its Waskom plant and sells ethane, propane, butane and natural gasoline to local markets.

Customers. Enable generates revenues from producers in the basins in which it operates. For the year ended December 31, 2017, Enable's top natural gas gathering and processing customers by gathered volumes were Continental Resources, Inc., Vine Oil and Gas, GeoSouthern Energy Corporation, XTO Energy Inc., Tapstone Energy, LLC, Apache Corporation, BP America Production Company, affiliates of Chesapeake Energy Corporation, Covey Park Energy LLC and FourPoint Energy, LLC. For the year ended December 31, 2017, Enable's top ten natural gas producer customers accounted for approximately 70 percent of its gathered natural gas volumes.

Enable's Williston Basin gathering systems serve XTO Energy Inc. The rates and terms of service on Enable's Williston Basin crude oil gathering systems are regulated by the FERC under the Interstate Commerce Act, but Enable's Williston Basin produced water gathering systems are not FERC-regulated. As of December 31, 2017, XTO Energy Inc. was Enable's only customer on these systems.

Contracts. Enable's contracts typically provide for natural gas and crude oil gathering services that are fee-based and for natural gas processing arrangements that are fee-based, or percent-of-liquids, percent-of-proceeds or keep-whole based.

Under a typical fee-based processing arrangement, Enable processes the raw natural gas to extract the NGLs, purchases the NGLs from the producer less a fee, returns the processed natural gas to the producer and sells the NGLs for its own account.

Under a typical percent-of-liquids processing arrangement, Enable processes the raw natural gas to extract the NGLs, purchases the NGLs from the producer at a discount, returns the processed natural gas to the producer and sells the NGLs for its own account.

Under a typical percent-of-proceeds processing arrangement, Enable processes the raw natural gas to extract the NGLs, purchases the NGLs and an agreed upon percentage of the processed natural gas from the producer at a discount, returns the remaining processed natural gas to the producer and sells the purchased natural gas and NGLs for its own account.

Under a typical keep-whole arrangement, Enable processes raw natural gas to extract the NGLs, returns a quantity of the processed natural gas to the producer that is equivalent to the raw natural gas on a Btu basis and retains and sells the NGLs for its own account.

For the year ended December 31, 2017, 58 percent, 35 percent and seven percent of Enable's inlet volumes were under processing arrangements that were fee-based, percent-of-proceeds or percent-of-liquids and keep-whole, respectively. For the year ended December 31, 2017, 74 percent of Enable's gathering and processing gross margin was fee-based, and the remaining 26 percent of its gathering and processing gross margin was primarily from sales of commodities, including natural gas, NGLs and condensate received under percent-of-proceeds, percent-of-liquids and keep-whole arrangements.

In lean gas areas, such as the eastern Arkoma Basin and the Haynesville Shale of the Ark-La-Tex Basin, some of Enable's natural gas gathering contracts contain minimum volume commitments from Enable's customers. In addition, a portion of the crude oil gathered by Enable's crude oil gathering system is under a contract with a minimum volume commitment. Under a minimum volume commitment, a customer agrees to either deliver a minimum volume of natural gas or crude oil to Enable's system for service or pay the service fees for the minimum volume of natural gas or crude oil regardless of whether or not the minimum volume of natural gas or crude oil is delivered. Enable calls any payment for the difference between the volume gathered and the minimum volume committed a shortfall payment. Some of Enable's contracts provide its customers the option to elect to pay a higher gathering fee over the remaining term of the contract in lieu of making a shortfall payment. As of December 31, 2017, the percentage of Enable's gathering and processing gross margin attributable to natural gas gathering contracts with minimum volume commitments, and the volume commitment-weighted average remaining terms of those contracts, were as follows:

	Anadarko Basin	Arkoma Basin	Ark-La-Tex Basin	Williston Basin [B]	Total
Percentage of gathering and processing gross margin attributable to gathering contracts with minimum volume commitments	—%	7%	18%	2%	27%
Percentage attributable to shortfall payments [A]	—%	80%	39%	—%	47%
Volume commitment-weighted average remaining contract term (in years)	—	5.9	2.1	11.2	3.7

(A) Represents the percentage of gathering and processing gross margin from gathering contracts with minimum volume commitments that were attributable to shortfall payments.

(B) Under the Williston Basin contracts, if the customer ships in excess of the minimum volume, this volume commitment could end before the expiration of the contract term.

For Enable's gathering and processing contracts that do not have minimum volume commitments, Enable strives to obtain acreage dedications. Under an acreage dedication, a customer agrees to deliver all of the natural gas or crude oil produced from a given area to Enable's system for gathering and, if applicable, processing. As of December 31, 2017, the gross acres dedicated under gathering agreements and the volume-weighted average remaining term for all gathering and processing contracts were as follows:

	Anadarko Basin	Arkoma Basin	Ark-La-Tex Basin	Williston Basin	Total
Gross acreage dedication (in millions)	5.0	1.7	0.8	0.2	7.7
Volume-weighted average remaining contract term (in years)	6.1	2.3	5.4	11.9	5.5

Acquisitions. In the fourth quarter of 2017, Enable acquired Align Midstream, LLC, a midstream company with natural gas gathering and processing facilities in the Cotton Valley and Haynesville plays of the Ark-La-Tex Basin. The acquisition included approximately 190 miles of natural gas gathering pipelines across Rusk, Panola and Shelby counties in Texas and DeSoto Parish in Louisiana and a cryogenic natural gas processing plant in Panola County, Texas, with a capacity of 100 MMcf/d.

Competition. Competition to gather and process natural gas is primarily a function of gathering rate, processing value, system reliability, fuel rate, system run time, construction cycle time and prices at the wellhead. Enable's gathering and processing systems compete with gatherers and processors of all types and sizes, including those affiliated with various producers, other major pipeline companies and various independent midstream entities. In the process of selling NGLs, Enable competes against other natural gas processors extracting and selling NGLs. Enable's primary competitors are other midstream companies who are active in the regions where Enable operates.

Competition to gather crude oil and produced water is primarily a function of rates, terms of service, system reliability and construction cycle time. The rates and terms of service of Enable's crude oil gathering, but not its produced water gathering,

are FERC-regulated. Enable's Williston Basin gathering systems compete with other gatherers, including those affiliated with producers and other midstream companies.

Seasonality. While the results of Enable's gathering and processing segment are not materially affected by seasonality, from time to time its operations and construction of assets can be impacted by inclement weather.

Transportation and Storage

Enable owns and operates interstate and intrastate transportation and storage systems across nine states. Enable's transportation and storage systems consist primarily of its interstate systems, EGT and MRT, its intrastate system, EOIT, and its investment in SESH. Enable's transportation and storage assets transport natural gas from areas of production and interconnected pipelines to power plants, LDCs and industrial end users as well as interconnected pipelines for delivery to additional markets. Enable's transportation and storage assets also provide facilities where natural gas can be stored by customers.

The following table sets forth certain information regarding Enable's transportation and storage assets as of or for the year ended December 31, 2017:

Asset	Length (Miles)	Compression (Horsepower)	Average Throughput (TBtu/d)		Transportation Capacity (Bcf/d) [A]		Transportation Firm Contracted Capacity (Bcf/d) [B]		Storage Capacity (Bcf)		Storage Firm Contracted Capacity (Bcf/d)	
EGT	5,900	382,600	2.4		6.5		4.58		30.5		22.92	
MRT	1,600	119,700	0.8		1.7		1.63		31.5		28.77	
EOIT	2,200	218,900	1.9	(C)	—	(C)	—		24.0		11.5	
Subtotal	9,700	721,200	5.1		8.2		6.21		86.0		63.19	
SESH	290	107,800	—	(E)	1.1	(D)	—	(E)	—	(E)	—	(E)
Total	9,990	829,000	5.1		9.3		6.21		86.0		63.19	

(A) Actual volumes transported per day may be less than total firm contracted capacity based on demand.
(B) Includes contracts with Enable's affiliates and subsidiaries.
(C) Enable's EOIT pipeline system is a web-like configuration with multidirectional flow capabilities between numerous receipt and delivery points, which limits Enable's ability to determine an overall system capacity. During the year ended December 31, 2017, the peak daily throughput was 2.3 TBtu/d or, on a volumetric basis, 2.3 Bcf/d.
(D) SESH has 1.09 Bcf/d of transportation capacity from Perryville, Louisiana to its endpoint in Mobile County, Alabama.
(E) Enable owns a 50 percent interest in SESH and, as such, does not include certain information regarding its transportation and storage assets in the table above.

Enable's transportation and storage assets were designed and built to primarily serve large natural gas and electric utilities in its areas of operation. In addition, Enable's transportation and storage assets serve natural gas producers, industrial end users and natural gas marketers. For the year ended December 31, 2017, Enable's top transportation and storage customers by revenue were affiliates of CenterPoint, Spire Inc., American Electric Power Co., the Company, Continental Resources, Inc., XTO Energy Inc., Chesapeake Energy Corporation, Midcontinent Express Pipeline LLC, Entergy Corporation and Shell Energy North America.

From time to time, Enable's transportation and storage business involves the construction of natural gas pipelines as needed to serve Enable's existing and new customers. For example, during the year ended December 31, 2017, Enable added 4,500 horsepower of compression and invested $51 million in the construction of transportation pipelines. In April 2017, EGT announced the Cana and Sooner Trend Anadarko Basin Canadian and Kingfisher Counties Expansion project, a system expansion providing firm transportation service for growing Anadarko Basin production. The project’s foundation shipper, Newfield Exploration Company, entered into a 205,000 Dth/d firm natural gas transportation agreement with EGT. The 10-year contract is expected to start at an initial capacity of 45,000 Dth/d in early 2018 and grow to the full contracted capacity by the fourth quarter of 2018. In addition, Enable is currently building an approximately 80-mile pipeline to expand the EOIT system in connection with a 228,000 Dth/d firm natural gas transportation agreement with the Company that is expected to be in-service in late 2018.

Enable's transportation assets include approximately 10,000 miles of transportation pipelines in Texas, Oklahoma, Arkansas, Louisiana, Kansas and Missouri, providing access to natural gas supplies from the Anadarko, Arkoma and Ark-La-Tex Basins to natural gas consuming markets in the Southeastern, Northeastern and Midwestern U.S. Enable's storage assets, as of December 31, 2017, provide a combined capacity of 86.0 Bcf with 2.1 Bcf/d of aggregate maximum withdrawal capacity from Enable's seven storage facilities in Oklahoma, Louisiana and Illinois and from its undivided 1/12th interest in the Bistineau Storage

Facility in Louisiana. Boardwalk Pipeline Partners, LP owns an undivided 11/12th interest in, and operates, the Bistineau Storage Facility. In addition, Enable has contracted for 2.5 Bcf of firm storage capacity in Cardinal's Perryville salt cavern storage facility.

Enable's transportation and storage assets are comprised of three categories: (1) interstate transportation and storage, (2) intrastate transportation and storage and (3) Enable's investment in SESH.

Interstate Transportation and Storage

Enable's interstate transportation and storage business consists of EGT and MRT. As interstate pipelines, EGT and MRT are subject to regulation as natural gas companies by FERC under the Natural Gas Act of 1938.

EGT

EGT provides natural gas transportation and storage services primarily to customers in Oklahoma, Texas, Arkansas, Louisiana, Missouri and Kansas. In addition to 5,900 miles of interstate pipelines with capacity of 6.5 Bcf/d, EGT has two underground natural gas storage facilities in Oklahoma and one underground natural gas storage facility in Louisiana, which, as of December 31, 2017, operate at a combined capacity of 30.5 Bcf with 739 MMcf/d of aggregate maximum withdrawal capacity.

Customers. EGT primarily serves LDCs owned by CenterPoint, producers in key plays in the Mid-continent, power plants, other LDCs and industrial end-users. EGT's customers are primarily located in Arkansas, Louisiana, Oklahoma and Texas. For the year ended December 31, 2017, approximately 28 percent of EGT's service revenue was attributable to contracts with LDCs owned by CenterPoint with a volume-weighted average contract life of 3.0 years for transportation contracts and 3.2 years for storage contracts. In addition to CenterPoint's LDCs, EGT's other major customers include Continental Resources, Inc., American Electric Power Co., Chesapeake Energy Corporation and XTO Energy Inc.

Contracts. Although EGT has established maximum rates for interstate transportation and storage services as required by the FERC, EGT is authorized to enter into negotiated rate and discounted rate agreements with its customers. EGT's services are typically provided under firm, fee-based transportation and storage agreements. For the year ended December 31, 2017, approximately 53 percent of Enable's transportation and storage gross margin was derived from EGT's firm contracts, 70 percent of EGT's transportation capacity was under firm contracts with a volume-weighted average remaining contract life of 3.2 years, and 75 percent of EGT's storage capacity was under firm contracts with a volume-weighted average remaining contract life of 3.2 years. EGT's firm transportation contracts representing 10 percent of CenterPoint's LDCs firm transportation capacity are scheduled to expire in March 2018 and 90 percent are scheduled to expire in March 2021. All of CenterPoint's LDCs firm storage contracts with EGT are scheduled to expire in March 2021.

Seasonality. EGT provides gas transmission delivery services to LDCs owned by CenterPoint in Arkansas, Louisiana, Oklahoma and Texas. Customer demand for natural gas on EGT is usually greater during the winter, primarily due to LDC demand to serve residential and commercial natural gas requirements. In addition, EGT experiences seasonal impacts associated with storage spreads and basis spreads on interconnected pipelines, as well as power plant demand.

Competition. EGT competes with a variety of other interstate and intrastate pipelines across Texas, Oklahoma, Arkansas and Louisiana. Enable's management views the principal elements of competition among pipelines as rates and terms, flexibility and reliability of service. EGT provides both flexibility and reliability of service with access to multiple sources of supply in the Anadarko, Arkoma and Ark-La-Tex Basins and access to multiple markets in the Midwest, Northeast and Southeast through interconnections with other pipelines. EGT's interconnections with other pipelines are primarily at Enable's Perryville Hub.

MRT

MRT provides natural gas transportation and storage services principally in Texas, Arkansas, Louisiana, Missouri and Illinois. In addition to 1,600 miles of interstate pipelines with capacity of 1.7 Bcf/d, MRT has one underground natural gas storage facility in Louisiana and one underground natural gas storage facility in Illinois, which, as of December 31, 2017, operate at a combined capacity of 31.5 Bcf with 717 MMcf/d of aggregate maximum withdrawal capacity.

Customers. MRT primarily serves the St. Louis LDC owned by Spire Inc. For the year ended December 31, 2017, 61 percent of MRT's service revenue was attributable to Spire Inc. under contracts with a volume-weighted average contract life of 1.3 years for transportation contracts and 1.4 years for storage contracts. MRT's other customers include utilities and industrial end users. MRT's customers are primarily located in Arkansas, Missouri and Illinois.

Contracts. MRT's services are typically provided under firm, fee-based transportation and storage agreements, with rates and terms of service regulated by the FERC. For the year ended December 31, 2017, approximately 14 percent of Enable's transportation and storage gross margin was derived from MRT's firm contracts, 96 percent of MRT's transportation capacity was under firm contracts with a volume-weighted average remaining contract life of 1.9 years and 91 percent of MRT's storage capacity was under firm contracts with a volume-weighted average remaining contract life of 1.6 years. MRT's firm transportation contracts representing 63 percent of Spire Inc.'s firm transportation capacity are scheduled to expire in July 2018, and 37 percent of Spire Inc.'s firm transportation capacity are scheduled to expire in July 2020. All of Spire Inc.'s firm storage contracts are scheduled to expire in May 2019.

In January 2017, Spire Inc. filed an application with the FERC to construct the Spire STL Pipeline, which would be an additional interstate pipeline serving the St. Louis, Missouri market. Subject to receiving approval of the proposed project from the FERC, Spire Inc. has indicated that it is targeting an early to mid-2019 in-service date for this pipeline. If Spire Inc. constructs this pipeline, Enable anticipates that Spire Inc.'s need for firm transportation and storage capacity on MRT will decrease.

Seasonality. Customer demand for natural gas on MRT is usually greater during the winter, primarily due to LDC demand to serve residential and commercial natural gas requirements. In addition, MRT experiences seasonal impacts associated with storage spreads and basis spreads on market-based pipelines.

Competition. MRT competes with various intrastate pipelines providing natural gas to the St. Louis market. In addition, MRT, from time-to-time, competes with potential projects to connect one or more third party interstate pipelines to the St. Louis market, such as the proposed Spire Inc. STL Pipeline. Enable's management views the principal elements of competition among pipelines as rates, terms of service, flexibility and reliability of service. MRT, through its interconnections with a variety of interstate and intrastate pipelines and its access to supply from a variety of producing basins, provides its customers with access to a variety of natural gas supply sources.

Intrastate Transportation and Storage

Enable's intrastate transportation and storage assets consist primarily of EOIT. EOIT provides transportation and storage services in Oklahoma. Enable's EOIT system delivers natural gas from the Arkoma and Anadarko Basins, including growth areas in the Cana Woodford, Granite Wash, Cleveland, Tonkawa, South Central Oklahoma Oil Province, Sooner Trend Anadarko Basin Canadian and Kingfisher Counties and Mississippi Lime Shale plays in western Oklahoma and the Texas panhandle, to utilities and industrial end users connected to EOIT and to interstate and intrastate pipelines interconnected with EOIT. EOIT had 1.88 TBtu/d of average daily throughput for the year ended December 31, 2017. In addition to the 2,200 miles of intrastate pipelines, EOIT has two underground natural gas storage facilities in Oklahoma, which, as of December 31, 2017 operate at a combined capacity of 24 Bcf with 605 MMcf/d of aggregate maximum withdrawal capacity. As of December 31, 2017, Enable's intrastate transportation also included a 20-mile intrastate pipeline in Illinois. This 20-mile intrastate pipeline became part of the MRT system on January 1, 2018.

Customers. EOIT's customers include Oklahoma's two largest electric utilities, OG&E and Public Service Company of Oklahoma, an affiliate of American Electric Power Co. For the year ended December 31, 2017, approximately six percent of Enable's total transportation and storage gross margin was attributable to a firm contract with its affiliate OG&E, and approximately three percent of Enable's transportation and storage gross margin was attributable to a firm contract with Public Service Company of Oklahoma. Enable's transportation agreement with OG&E extends through April 30, 2019 and will remain in effect year to year thereafter unless either party provides notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period. Enable's transportation agreement with Public Service Company of Oklahoma extends through December 31, 2020 and includes the option for a one-year extension. EOIT's customers also include other electric generators, LDCs, Arkoma and Anadarko Basin producers and industrial end users.

Contracts. EOIT provides fee-based firm and interruptible transportation and storage services on both an intrastate basis and, pursuant to Section 311 of the Natural Gas Policy Act of 1978, on an interstate basis. For the year ended December 31, 2017, approximately 21 percent of Enable's transportation and storage gross margin was derived from EOIT's firm contracts. EOIT's transportation capacity was under firm contracts with a volume-weighted average remaining contract life of 5.5 years, and EOIT's storage capacity was under firm contracts with a volume-weighted average remaining contract life of 0.9 years.

Seasonality. EOIT provides gas transmission delivery services to the majority of OG&E's and all of Public Service Company of Oklahoma's natural gas-fired electric generation facilities in Oklahoma. Customer demand for natural gas transportation and storage services on EOIT is usually greater during the summer, primarily due to demand by natural gas-fired power plants to serve residential and commercial electricity requirements.

Competition. EOIT competes with a variety of interstate and intrastate pipelines in providing transportation and storage services in Oklahoma, including competing against several pipelines with which EOIT interconnects. Enable's management views competition in the transportation and storage market as primarily a function of rates, terms of services, flexibility and reliability of service. EOIT's integrated transportation and storage system allows Enable to provide load following service to natural gas-fired power plants to allow the power plants the ability to regulate generation and meet the instantaneous changes in customer demand for electricity.

Enable's Investment in SESH

SESH is an approximately 290-mile interstate pipeline that provides transportation services in Louisiana, Mississippi and Alabama. Enable owns a 50 percent interest in SESH and provides field operations for the pipeline. Spectra Energy Partners, LP owns the remaining 50 percent interest in SESH and provides gas control and commercial operations for the pipeline. As of December 31, 2017, SESH had 1.09 Bcf/d of transportation capacity from Perryville, Louisiana to its endpoint in Mobile County, Alabama.

Customers and Contracts. SESH's customers are primarily companies that generate electricity for the Florida power market. The rates charged by SESH for interstate transportation services are regulated by the FERC. SESH's transportation services are typically provided under firm, fee-based negotiated rate agreements. SESH's transportation contracts have a volume-weighted average remaining contract life of 4.4 years.

Seasonality. SESH is generally not impacted by seasonality, SESH's load factor generally remains constant throughout the year.

Competition. SESH competes with other interstate and intrastate pipelines providing access to the Southeast power generation market. Enable's management views the principal elements of competition among pipelines as rates and terms, flexibility and reliability of service.

ENVIRONMENTAL MATTERS

General

The activities of the Company are subject to numerous stringent and complex federal, state and local laws and regulations governing environmental protection. These laws and regulations can change, restrict or otherwise impact OG&E's business activities in many ways, including the handling or disposal of waste material, planning for future construction activities to avoid or mitigate harm to threatened or endangered species and requiring the installation and operation of emissions control equipment. Failure to comply with these laws and regulations could result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Management believes that all of its operations are in substantial compliance with current federal, state and local environmental standards.

In the past, environmental regulation caused the Company to incur significant costs because the trend was to place more and more restrictions and limitations on the Company's activities. The Trump administration has delayed, reversed or proposed to repeal some of these regulations and generally has not sought to adopt new, more stringent regulations. Nonetheless, the Company continues to have obligations to take or complete action under previously adopted environmental rules, and the Company cannot assure that future events, such as changes in existing laws, the promulgation of new laws or regulations or the development or discovery of new facts or conditions will not cause it to incur significant costs for environmental matters.

It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2018 will be $189.2 million, of which $170.0 million is for capital expenditures. It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2019 will be approximately $51.8 million, of which $35.2 million is for capital expenditures. The amounts for OG&E above include capital expenditures for Dry Scrubbers and conversion of two coal-fueled units to natural gas. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

For a further discussion of environmental matters that may affect the Company, see "Environmental Laws and Regulations" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

FINANCE AND CONSTRUCTION

Future Capital Requirements

Capital Requirements

The Company's primary needs for capital are related to acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E. Other working capital requirements are expected to be primarily related to maturing debt, operating lease obligations, fuel clause under and over recoveries and other general corporate purposes. The Company generally meets its cash needs through a combination of cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings. See "Liquidity and Capital Resources" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of the Company's capital requirements.

Capital Expenditures

The Company's consolidated estimates of capital expenditures for the years 2018 through 2022 are shown in the following table. These capital expenditures represent the base maintenance capital expenditures (i.e., capital expenditures to maintain and operate the Company's businesses) plus capital expenditures for known and committed projects. Estimated capital expenditures for Enable are not included in the table below.

(In millions)	2018	2019	2020	2021	2022
Transmission (A)	$ 90	$ 50	$ 50	$ 50	$ 50
Distribution:					
Oklahoma	215	165	165	165	165
Arkansas	10	20	50	60	60
Generation	55	130	95	75	75
Other	50	25	25	25	25
Total Transmission, Distribution, Generation and Other	420	390	385	375	375
Projects:					
Environmental - Dry Scrubbers (B)	95	20	—	—	—
Combustion turbines - Mustang	35	—	—	—	—
Environmental - natural gas conversion (B)	35	15	—	—	—
Allowance of funds used during construction and ad valorem taxes	40	—	—	—	—
Grid modernization, reliability, resiliency, technology and other	—	200	190	280	180
Total Projects	205	235	190	280	180
Total	$ 625	$ 625	$ 575	$ 655	$ 555

(A) Future transmission capital expenditures include the following:

Project Type	Project Description	Estimated Cost (In millions)	Projected In-Service Date
Integrated Transmission Project	126 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to OG&E's Cimarron substation and construction of the Mathewson substation on this transmission line. $150.0 million has been spent prior to 2018.	$158	First quarter 2018

(B) Represent capital costs associated with OG&E's ECP to comply with the EPA's Regional Haze Rule. More detailed discussion regarding the Regional Haze Rule and OG&E's ECP can be found in Note 14 in "Item 8. Financial Statements and Supplementary Data" and in "Environmental Laws and Regulations" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in electric transmission assets, will be evaluated based upon their impact upon achieving the Company's financial objectives.

Pension and Postretirement Benefit Plans

The Company made a $20.0 million contribution to its Pension Plan in both 2017 and 2016. The Company has not determined whether it will need to make any contributions to the Pension Plan in 2018. See "Future Capital Requirements" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for further discussion of the Company's pension and postretirement benefit plans.

Common Stock Dividends

At the Company's September 2017 board meeting, the Board of Directors approved management's recommendation of a 10 percent increase in the quarterly dividend rate to $0.33250 per share from $0.30250 per share effective in October 2017. See "Future Capital Requirements" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for further discussion.

Financing Activities and Future Sources of Financing

Management expects that cash generated from operations, proceeds from the issuance of long and short-term debt, proceeds from the sales of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan or other offerings and distributions from Enable will be adequate over the next three years to meet anticipated cash needs and to fund future growth opportunities. The Company utilizes short-term borrowings (through a combination of bank borrowings and commercial paper) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

Short-Term Debt and Credit Facilities

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreement. In March 2017, the Company and OG&E each entered into new $450.0 million unsecured revolving credit agreements which expire March 2022. These bank facilities can also be used as letter of credit facilities. As of December 31, 2017, the Company had $168.4 million of short-term debt compared to $236.2 million at December 31, 2016. The average balance of short-term debt in 2017 was $175.7 million at a weighted-average interest rate of 1.30 percent. The maximum month-end balance of short-term debt in 2017 was $260.1 million. At December 31, 2017, the Company had $731.3 million of net available liquidity under its revolving credit agreements. OG&E has the necessary regulatory approvals to incur up to $800.0 million in short-term borrowings at any one time for a two-year period beginning January 1, 2017 and ending December 31, 2018. At December 31, 2017, the Company had $14.4 million in cash and cash equivalents. See Note 10 in "Item 8. Financial Statements and Supplementary Data" for further discussion.

Issuance of Long-Term Debt

In March 2017, OG&E issued $300.0 million of 4.15 percent senior notes due April 1, 2047. The proceeds from the issuance were used for general corporate purposes, including to repay short-term debt, to repay borrowings under the revolving credit facility, to fund the payment of OG&E's $125.0 million of 6.5 percent senior notes that matured on July 15, 2017 and to fund ongoing capital expenditures and working capital.

In August 2017, OG&E issued $300.0 million of 3.85 percent senior notes due August 15, 2047. The proceeds from the issuance were used for general corporate purposes, including to repay short-term debt, to repay borrowings under the revolving credit facility and to fund ongoing capital expenditures and working capital.

Common Stock

The Company does not expect to issue any common stock in 2018 from its Automatic Dividend Reinvestment and Stock Purchase Plan. See Note 8 in "Item 8. Financial Statements and Supplementary Data" for a discussion of the Company's common stock activity.

Distributions by Enable

Pursuant to the Enable Limited Partnership Agreement, Enable made distributions of $141.2 million, $141.2 million and $139.3 million during the years ended December 31, 2017, 2016 and 2015, respectively.

EMPLOYEES

The Company had 2,413 employees at December 31, 2017, of which 140 are seconded to Enable.

EXECUTIVE OFFICERS

The following persons were Executive Officers of the Registrant as of February 21, 2018:

Name	Age	Title
Sean Trauschke	50	Chairman of the Board, President and Chief Executive Officer - OGE Energy Corp.
E. Keith Mitchell	55	Chief Operating Officer - OG&E
Stephen E. Merrill	53	Chief Financial Officer - OGE Energy Corp.
Scott Forbes (A)	60	Controller and Chief Accounting Officer - OGE Energy Corp.
Patricia D. Horn	59	Vice President - Governance and Corporate Secretary - OGE Energy Corp.
Jean C. Leger, Jr.	59	Vice President - Utility Operations - OG&E
Kenneth R. Grant	53	Vice President- Sales and Marketing - OG&E
Cristina F. McQuistion	53	Vice President - Chief Information Officer - OG&E
Jerry A. Peace	55	Vice President- Integrated Resource Planning and Development - OG&E
Sarah R. Stafford (A)	36	Accounting Research Officer - OGE Energy Corp.
William H. Sultemeier	50	General Counsel - OGE Energy Corp.
Charles B. Walworth	43	Treasurer - OGE Energy Corp.

(A) Mr. Forbes is resigning as Controller and Chief Accounting Officer, effective as of February 28, 2018. Ms. Stafford will succeed Mr. Forbes as Controller and Chief Accounting Officer, effective March 1, 2018. Ms. Stafford was not an Executive Officer as of February 21, 2018.

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Trauschke, Merrill, Forbes, Sultemeier, Walworth and Ms. Horn are also officers of OG&E. Each Executive Officer is to hold office until the Board of Directors meeting following the next Annual Meeting of Shareholders, currently scheduled for May 17, 2018.

Messrs. Trauschke and Merrill are members of the Board of Directors of Enable GP, LLC, the general partner of Enable.

The business experience of each of the Executive Officers of the Registrant for the past five years is as follows:

Name		Business Experience
Sean Trauschke	2015 - Present:	Chairman of the Board, President and Chief Executive Officer of OGE Energy Corp.
	2014 - 2015:	President of OGE Energy Corp.
	2013 - 2014:	Vice President and Chief Financial Officer of OGE Energy Corp.
E. Keith Mitchell	2015 - Present:	Chief Operating Officer of OG&E
	2013 - 2015:	Executive Vice President and Chief Operating Officer of Enable Midstream Partners, LP
	2013:	President and Chief Operating Officer of Enogex Holdings; President of Enogex LLC
Stephen E. Merrill	2014 - Present:	Chief Financial Officer of OGE Energy Corp.
	2013 - 2014:	Executive Vice President of Finance and Chief Administrative Officer of Enable Midstream Partners, LP
	2013:	Chief Operating Officer of Enogex LLC
Scott Forbes	2013 - Present:	Controller and Chief Accounting Officer of OGE Energy Corp.
Patricia D. Horn	2014 - Present:	Vice President - Governance and Corporate Secretary of OGE Energy Corp.
	2013 - 2014:	Vice President - Governance, Environmental and Corporate Secretary of OGE Energy Corp.
Jean C. Leger, Jr.	2013 - Present:	Vice President - Utility Operations of OG&E
Kenneth R. Grant	2016 - Present:	Vice President - Sales and Marketing of OG&E
	2015:	Vice President Marketing and Product Development of OG&E
	2013 - 2015:	Managing Director Tech Solutions & Ops of OG&E
	2013:	Managing Director Customer Solutions of OG&E
Cristina F. McQuistion	2017 - Present:	Vice President - Chief Information Officer of OG&E
	2016 - 2017:	Vice President - Chief Information Officer and Utility Strategy of OG&E
	2014 - 2015:	Vice President - Strategic Planning, Performance Improvement and Chief Information Officer of OG&E
	2013 - 2014:	Vice President - Strategic Planning, Performance Improvement and Chief Information Officer of OGE Energy Corp. and OG&E
Jerry A. Peace	2016 - Present:	Vice President - Integrated Resource Planning and Development of OG&E
	2014 - 2015:	Chief Generation Planning and Procurement Officer of OG&E
	2013 - 2014:	Chief Risk Officer of OGE Energy Corp.
Sarah R. Stafford (A)	2016 - Present:	Accounting Research Officer of OGE Energy Corp.
	2013 - 2016:	Senior Manager - Ernst & Young, LLP
William H. Sultemeier	2017 - Present:	General Counsel of OGE Energy Corp.
	2016:	Partner - Jones Day
	2013-2015:	Shareholder - Greenberg Traurig, LLP
Charles B. Walworth	2014 - Present:	Treasurer of OGE Energy Corp.
	2013 - 2014:	Assistant Treasurer of OGE Energy Corp.

(A) Ms. Stafford was not an Executive Officer as of February 21, 2018.

ACCESS TO SECURITIES AND EXCHANGE COMMISSION FILINGS

The Company's website address is *www.oge.com.* Through the Company's website under the heading "Investors," "Investor Relations," "SEC Filings," the Company makes available, free of charge, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission. Our Internet website and the information contained therein or connected thereto are not intended to be incorporated into this Form 10-K and should not be considered a part of this Form 10-K.

Item 1A. Risk Factors.

In the discussion of risk factors set forth below, unless the context otherwise requires, the terms "we," "our" and "us" refer to the Company. In addition to the other information in this Form 10-K and other documents filed by us and/or our subsidiaries with the Securities and Exchange Commission from time to time, the following factors should be carefully considered in evaluating OGE Energy and its subsidiaries. Such factors could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by or on behalf of us or our subsidiaries. Additional risks and uncertainties not currently known to us or that we currently view as immaterial may also impair our business operations.

REGULATORY RISKS

OG&E's profitability depends to a large extent on the ability to fully recover its costs from its customers in a timely manner, and there may be changes in the regulatory environment that impair its ability to recover costs from its customers.

OG&E is subject to comprehensive regulation by several federal and state utility regulatory agencies, which significantly influences its operating environment and its ability to fully recover its costs from utility customers. Recoverability of any under recovered amounts from OG&E's customers due to a rise in fuel costs is a significant risk. The utility commissions in the states where OG&E operates regulate many aspects of its utility operations including siting and construction of facilities, customer service and the rates that OG&E can charge customers. The profitability of the utility operations is dependent on OG&E's ability to fully recover costs related to providing energy and utility services to its customers in a timely manner. Any failure to obtain utility commission approval to increase rates to fully recover costs, or a delay in the receipt of such approval, could have an adverse impact on OG&E's results of operations. In addition, OG&E's jurisdictions have fuel adjustment clauses that permit OG&E to recover fuel costs through rates without a general rate case, subject to a later determination that such fuel costs were prudently incurred. If the state regulatory commissions determine that the fuel costs were not prudently incurred, recovery could be disallowed.

In recent years, the regulatory environments in which OG&E operates have received an increased amount of attention. It is possible that there could be changes in the regulatory environment that would impair OG&E's ability to fully recover costs historically paid by OG&E's customers. State utility commissions generally possess broad powers to ensure that the needs of the utility customers are being met. OG&E cannot assure that the OCC, APSC and the FERC will grant rate increases in the future or in the amounts requested, and they could instead lower OG&E's rates.

OG&E is unable to predict the impact on its operating results from future regulatory activities of any of the agencies that regulate OG&E. Changes in regulations or the imposition of additional regulations could have an adverse impact on OG&E's results of operations.

OG&E's rates are subject to rate regulation by the states of Oklahoma and Arkansas, as well as by a federal agency, whose regulatory paradigms and goals may not be consistent.

OG&E is currently a vertically integrated electric utility. Most of its revenue results from the sale of electricity to retail customers subject to bundled rates that are approved by the applicable state utility commission.

OG&E operates in Oklahoma and western Arkansas and is subject to rate regulation by the OCC and the APSC, in addition to FERC regulation of its transmission activities and any wholesale sales. Exposure to inconsistent state and federal regulatory standards may limit our ability to operate profitably. Further alteration of the regulatory landscape in which we operate, including a change in our authorized return on equity, may harm our financial position and results of operations.

Costs of compliance with environmental laws and regulations are significant, and the cost of compliance with future environmental laws and regulations may adversely affect our results of operations, consolidated financial position or liquidity.

We are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, wildlife conservation, natural resources and health and safety that could, among other things, restrict or limit the output of certain facilities or the use of certain fuels required for the production of electricity and/or require additional pollution control equipment and otherwise increase costs. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations and those costs may be even more significant in the future.

In response to recent regulatory and judicial decisions and international accords, emissions of greenhouse gases including, most significantly, CO_2 could be restricted in the future as a result of federal or state legal requirements or litigation relating to

greenhouse gas emissions. No rules are currently in effect that require us to reduce our greenhouse gas emissions, but if such rules were to become effective, they could result in significant additional compliance costs that would affect our future consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates.

There is inherent risk of the incurrence of environmental costs and liabilities in our operations and historical industry operations practices. These activities are subject to stringent and complex federal, state and local laws and regulations that can restrict or impact OG&E's business activities in many ways, such as restricting the way OG&E can handle or dispose of its wastes or requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators. OG&E may be unable to recover these costs from insurance or other regulatory mechanisms. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase compliance costs and the cost of any remediation that may become necessary.

For further discussion of environmental matters that may affect the Company, see "Environmental Laws and Regulations" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions.

OG&E's business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades and retrofits and modernizing existing infrastructure as well as other initiatives. Significant portions of OG&E's facilities were constructed many years ago. Older generation equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to maintain efficiency, to comply with changing environmental requirements or to provide reliable operations. OG&E currently provides service at rates approved by one or more regulatory commissions. If these regulatory commissions do not approve adjustments to the rates OG&E charges, it would not be able to recover the costs associated with its planned extensive investment. This could adversely affect OG&E's financial position and results of operations. While OG&E may seek to limit the impact of any denied recovery by attempting to reduce the scope of its capital investment, there can be no assurance as to the effectiveness of any such mitigation efforts, particularly with respect to previously incurred costs and commitments.

As of December 31, 2017, OG&E had invested $401.3 million in the Dry Scrubbers and $348.4 million in the Mustang Modernization Plan.

The regional power market in which OG&E operates has changing transmission regulatory structures, which may affect the transmission assets and related revenues and expenses.

OG&E currently owns and operates transmission and generation facilities as part of a vertically integrated utility. OG&E is a member of the SPP regional transmission organization and has transferred operational authority (but not ownership) of OG&E's transmission facilities to the SPP. The SPP has implemented regional day ahead and real-time markets for energy and operating reserves, as well as associated transmission congestion rights. Collectively the three markets operate together under the global name, SPP Integrated Marketplace. OG&E represents owned and contracted generation assets and customer load in the SPP Integrated Marketplace for the sole benefit of its customers. OG&E has not participated in the SPP Integrated Marketplace for any speculative trading activities. OG&E records the SPP Integrated Marketplace transactions as sales or purchases with results reported as Operating Revenues or Cost of Sales in its Consolidated Financial Statements. OG&E's revenues, expenses, assets and liabilities may be adversely affected by changes in the organization, operation and regulation of the SPP Integrated Marketplace by the FERC or the SPP.

Increased competition resulting from restructuring efforts could have a significant financial impact on us and consequently decrease our revenue.

We have been and will continue to be affected by competitive changes to the utility and energy industries. Significant changes have occurred and additional changes have been proposed to the wholesale electric market. Although retail restructuring efforts in Oklahoma and Arkansas have been postponed for the time being, if such efforts were renewed, retail competition and the unbundling of regulated energy service could have a significant financial impact on us due to possible impairments of assets, a loss of retail customers, lower profit margins and/or increased costs of capital. Any such restructuring could have a significant impact on our consolidated financial position, results of operations and cash flows. We cannot predict when we will be subject to changes in legislation or regulation, nor can we predict the impact of these changes on our consolidated financial position, results of operations or cash flows.

Events that are beyond our control have increased the level of public and regulatory scrutiny of our industry. Governmental and market reactions to these events may have negative impacts on our business, consolidated financial position, results of operations, cash flows and access to capital.

As a result of accounting irregularities at public companies in general, and energy companies in particular, and investigations by governmental authorities into energy trading activities, public companies, including those in the regulated and unregulated utility business, have been under public and regulatory scrutiny and suspicion. The accounting irregularities have caused regulators and legislators to review current accounting practices, financial disclosures and relationships between companies and their independent auditors. The capital markets and rating agencies also have increased their level of scrutiny. We believe that we are complying with all applicable laws and accounting standards, but it is difficult or impossible to predict or control what effect these types of events may have on our business, consolidated financial position, cash flows or access to the capital markets. It is unclear what additional laws or regulations may develop, and we cannot predict the ultimate impact of any future changes in accounting regulations or practices in general with respect to public companies, the energy industry or our operations specifically. Any new accounting standards could affect the way we are required to record revenues, expenses, assets, liabilities and equity. These changes in accounting standards could lead to negative impacts on reported earnings or decreases in assets or increases in liabilities that could, in turn, affect our consolidated financial position, results of operations and cash flows.

We are subject to substantial utility and energy regulation by governmental agencies. Compliance with current and future utility and energy regulatory requirements and procurement of necessary approvals, permits and certifications may result in significant costs to us.

We are subject to substantial regulation from federal, state and local regulatory agencies. We are required to comply with numerous laws and regulations and to obtain permits, approvals and certifications from the governmental agencies that regulate various aspects of our businesses, including customer rates, service regulations, retail service territories, sales of securities, asset acquisitions and sales, accounting policies and practices and the operation of generating facilities. We believe the necessary permits, approvals and certificates have been obtained for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from future regulatory activities of these agencies.

In compliance with the Energy Policy Act of 2005, the FERC approved the NERC as the national energy reliability organization. The NERC is responsible for the development and enforcement of mandatory reliability and cyber security standards for the wholesale electric power system. OG&E's plan is to comply with all applicable standards and to expediently correct a violation should it occur. One of OG&E's regulators, NERC, has comprehensive regulations and standards related to the reliability and security of our operating systems, and is continuously developing additional mandatory compliance requirements for the utility industry. The increasing development of NERC rules and standards will increase compliance costs and our exposure for potential violations of these standards.

OPERATIONAL RISKS

Our results of operations may be impacted by disruptions beyond our control.

We are exposed to risks related to performance of contractual obligations by our suppliers. We are dependent on coal and natural gas for much of our electric generating capacity. We rely on suppliers to deliver coal and natural gas in accordance with short and long-term contracts. We have certain supply contracts in place; however, there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply coal and natural gas to us. The suppliers under these agreements may experience financial or technical problems that inhibit their ability to fulfill their obligations to us. In addition, the suppliers under these agreements may not be required to supply coal and natural gas to us under certain circumstances, such as in the event of a natural disaster. Deliveries may be subject to short-term interruptions or reductions due to various factors, including transportation problems, weather and availability of equipment. Failure or delay by our suppliers of coal and natural gas deliveries could disrupt our ability to deliver electricity and require us to incur additional expenses to meet the needs of our customers.

Also, because our generation and transmission systems are part of an interconnected regional grid, we face the risk of possible loss of business due to a disruption or black-out caused by an event such as a severe storm or generator or transmission facility outage on a neighboring system or the actions of a neighboring utility. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material adverse impact on our consolidated financial position, results of operations and cash flows.

OG&E's electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased purchase power costs.

OG&E owns and operates coal-fired, natural gas-fired, wind-powered and solar-powered generating facilities. Operation of electric generating facilities involves risks that can adversely affect energy output and efficiency levels. Included among these risks are:

- increased prices for fuel and fuel transportation as existing contracts expire;
- facility shutdowns due to a breakdown or failure of equipment or processes or interruptions in fuel supply;
- operator error or safety related stoppages;
- disruptions in the delivery of electricity; and
- catastrophic events such as fires, explosions, tornadoes, floods, earthquakes or other similar occurrences.

When unplanned maintenance work is required on power plants or other equipment, OG&E will not only incur unexpected maintenance expenses, but it may also have to make spot market purchases of replacement electricity that could exceed OG&E's costs of generation or be forced to retire a generation unit if the cost or timing of the maintenance is not reasonable and prudent. If OG&E is unable to recover any of these increased costs in rates, it could have a material adverse effect on our financial performance.

Changes in technology, regulatory policies and customer electricity consumption may cause our generating facilities to be less competitive and impact our results of operations.

OG&E primarily generates electricity at large central facilities. This method typically results in economies of scale and lower costs than newer technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in technologies or changes in regulatory policies will reduce costs of new technology to levels that are equal to or below that of most central station electricity production, which could have a material adverse effect on our results of operations. OG&E's widespread use of Smart Grid technology allowing for two-way communications between the utility and its customers could enable the entry of technology companies into the interface between OG&E and its customers, resulting in unpredictable effects on our current business.

Reductions in customer electricity consumption, thereby reducing utility electric sales, could result from increased deployment of renewable energy technologies as well as increased efficiency of household appliances, among other general efficiency gains in technology. However, this potential reduction in load would not reduce our need for ongoing investments in our infrastructure to reliably serve our customers. Continued utility infrastructure investment without increased electricity sales could cause increased rates for customers, potentially resulting in further reductions in electricity sales and reduced profitability.

Economic conditions could negatively impact our business and our results of operations.

Our operations are affected by local, national and worldwide economic conditions. The consequences of a prolonged recession could include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. A lower level of economic activity could result in a decline in energy consumption, which could adversely affect our revenues and future growth. Instability in the financial markets, as a result of recession or otherwise, also could affect the cost of capital and our ability to raise capital. Economic conditions may also impact the valuation of certain long-lived assets, including our investment in unconsolidated affiliates, that are subject to impairment testing, potentially resulting in impairment charges, which could have a material adverse impact on our results of operations.

Current economic conditions may be exacerbated by insufficient financial sector liquidity leading to potential increased unemployment, which could impact the ability of our customers to pay timely, increase customer bankruptcies, and could lead to increased bad debt. If such circumstances occur, we expect that commercial and industrial customers would be impacted first, with residential customers following.

In addition, economic conditions, particularly budget shortfalls, could increase the pressure on federal, state and local governments to raise additional funds by increasing corporate tax rates and/or delaying, reducing or eliminating tax credits, grants or other incentives that could have a material adverse impact on our consolidated results of operations and cash flows.

We are subject to financial risks associated with climate change.

Climate change creates financial risk. Potential regulation associated with climate change legislation could pose financial risks to the Company. In addition, to the extent that any climate change adversely affects the national or regional economic health through physical impacts or increased rates caused by the inclusion of additional regulatory imposed costs, CO_2 taxes or costs associated with additional regulatory requirements, the Company may be adversely impacted. A declining economy could adversely impact the overall financial health of the Company due to a lack of load growth and decreased sales opportunities. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

We are subject to cybersecurity risks and increased reliance on processes automated by technology.

In the regular course of our businesses, we handle a range of sensitive security and customer information. We are subject to laws and rules issued by different agencies concerning safeguarding and maintaining the confidentiality of this information. A security breach of our information systems such as theft or inappropriate release of certain types of information, including confidential customer information or system operating information, could have a material adverse impact on our consolidated financial position, results of operations and cash flows.

OG&E operates in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite implementation of security measures, the technology systems are vulnerable to disability, failures or unauthorized access. Such failures or breaches of the systems could impact the reliability of OG&E's generation, transmission and distribution systems which may result in a loss of service to customers and also subject OG&E to financial harm due to the significant expense to repair security breaches or system damage. The implementation of OG&E's Smart Grid program further increases potential risks associated with cybersecurity attacks. Our generation and transmission systems are part of an interconnected system. Therefore, a disruption caused by the impact of a cybersecurity incident of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third party service providers' operations, could also negatively impact our business. If the technology systems were to fail or be breached and not recovered in a timely manner, critical business functions could be impaired and sensitive confidential data could be compromised, which could have a material adverse impact on its consolidated financial position, results of operations and cash flows.

Our security procedures, which include among others, virus protection software, cybersecurity and our business continuity planning, including disaster recovery policies and back-up systems, may not be adequate or implemented properly to fully address the adverse effect of cybersecurity attacks on our systems, which could adversely impact our operations.

We maintain property, casualty and cybersecurity insurance that may cover certain resultant physical damage or third-party injuries caused by potential cyber events. However, damage and claims arising from such incidents may exceed the amount of any insurance available and other damage and claims arising from such incidents may not be covered at all. For these reasons, a significant cyber incident could reduce future net income and cash flows and impact financial condition.

Terrorist attacks, and the threat of terrorist attacks, have resulted in increased costs to our business. Continued hostilities or sustained military campaigns may adversely impact our consolidated financial position, results of operations and cash flows.

The long-term impact of terrorist attacks and the magnitude of the threat of future terrorist attacks on the electric utility and natural gas midstream industry in general, and on us in particular, cannot be known. Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities or sustained military campaigns may affect our operations in unpredictable ways, including disruptions of supplies and markets for our products, and the possibility that our infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror. Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than existing insurance coverage.

Weather conditions such as tornadoes, thunderstorms, ice storms, wind storms, earthquakes and prolonged droughts, as well as seasonal temperature variations may adversely affect our consolidated financial position, results of operations and cash flows.

Weather conditions directly influence the demand for electric power. In OG&E's service area, demand for power peaks during the hot summer months, with market prices also typically peaking at that time. As a result, overall operating results may fluctuate on a seasonal and quarterly basis. In addition, we have historically sold less power, and consequently received less revenue, when weather conditions are milder. Unusually mild weather in the future could reduce our revenues, net income, available cash and borrowing ability. Severe weather, such as tornadoes, thunderstorms, ice storms, wind storms, earthquakes and prolonged droughts may cause outages and property damage which may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned, as described above, would be particularly burdensome during a peak demand period. In addition, prolonged droughts could cause a lack of sufficient water for use in cooling during the electricity generating process. Additionally, if climate change exacerbates physical changes in weather, operations may be impacted as discussed above.

FINANCIAL RISKS

Market performance, increased retirements, changes in retirement plan regulations and increasing costs associated with our Pension Plan, health care plans and other employee-related benefits may adversely affect our consolidated financial position, results of operations or cash flows.

We have a Pension Plan that covers a significant amount of our employees hired before December 1, 2009. We also have defined benefit postretirement plans that cover a significant amount of our employees hired prior to February 1, 2000. Assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions with respect to the defined benefit retirement and postretirement plans have a significant impact on our results of operations and funding requirements. Based on our assumptions at December 31, 2017, we expect to make future contributions to maintain required funding levels. It has been our practice to also make voluntary contributions to maintain more prudent funding levels than minimally required. We may continue to make voluntary contributions in the future. These amounts are estimates and may change based on actual stock market performance, changes in interest rates and any changes in governmental regulations.

If the employees who participate in the Pension Plan retire when they become eligible for retirement over the next several years, or if our plan experiences adverse market returns on its investments, or if interest rates materially fall, our pension expense and contributions to the plans could rise substantially over historical levels. The timing and number of employees retiring and selecting the lump-sum payment option could result in pension settlement charges that could materially affect our results of operations if we are unable to recover these costs through our electric rates. In addition, assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions, including projected retirements, have a significant impact on our consolidated financial position and results of operations. Those factors are outside of our control.

In addition to the costs of our Pension Plan, the costs of providing health care benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs related to health care plans for our employees, will continue to rise. The increasing costs and funding requirements with our Pension Plan, health care plans and other employee benefits may adversely affect our consolidated financial position, results of operations or liquidity.

Finally, the Company provides retirement benefits and retiree health care benefits to 140 employees seconded to Enable. If the seconding agreement was terminated, and those employees were no longer employed by the Company, and lump sum payments were made to those employees, the Company would recognize a settlement or curtailment of the pension/retiree health care charges, which would increase expense at the Company by approximately $14.6 million. Settlement and curtailment charges associated with the Enable seconded employees are not reimbursable to the Company by Enable. The seconding agreement can be terminated by mutual agreement of the Company and Enable or solely by the Company upon 120 day notice.

We face certain human resource risks associated with the availability of trained and qualified labor to meet our future staffing requirements.

Workforce demographic issues challenge employers nationwide and are of particular concern to the electric utility industry. The median age of utility workers is significantly higher than the national average. Over the next three years, 39 percent of our current employees will meet the eligibility requirements to retire. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business.

We are a holding company with our primary assets being investments in our subsidiary and equity investments.

We are a holding company and thus our investments in our subsidiary and unconsolidated affiliate, accounted for under the equity method, are our primary assets. Substantially all of our operations are conducted by our subsidiary and unconsolidated affiliate. Consequently, our operating cash flow and our ability to pay our dividends and service our indebtedness utilizes the operating cash flow of our subsidiary and unconsolidated affiliate and the payment of funds by them to us in the form of dividends or distributions. At December 31, 2017, the Company and its subsidiary had outstanding indebtedness and other liabilities of $6.6 billion. Our subsidiary and unconsolidated affiliate are separate legal entities that have no obligation to pay any amounts due on our indebtedness or to make any funds available for that purpose, whether by dividends or otherwise. In addition, their ability to pay dividends to us depends on any statutory and contractual restrictions that may be applicable to such subsidiary, which may include requirements to maintain minimum levels of working capital and other assets. Claims of creditors, including general creditors, of our subsidiary or unconsolidated affiliate on their respective assets will generally have priority over our claims (except to the extent that we may be a creditor of the subsidiaries and our claims are recognized) and claims by our shareholders.

In addition, as discussed above, OG&E is regulated by state utility commissions in Oklahoma and Arkansas as well as a federal regulatory agency which generally possess broad powers to ensure that the needs of the utility customers are being met. To the extent that the state commissions or federal regulatory agency attempt to impose restrictions on the ability of OG&E to pay dividends to us, it could adversely affect our ability to continue to pay dividends.

Certain provisions in our charter documents have anti-takeover effects.

Certain provisions of our certificate of incorporation and bylaws, as well as the Oklahoma corporation statute, may have the effect of delaying, deferring or preventing a change in control of the Company. Such provisions, including those regulating the nomination of directors, limiting who may call special stockholders' meetings and eliminating stockholder action by written consent, together with the possible issuance of preferred stock of the Company without stockholder approval, may make it more difficult for other persons, without the approval of our board of directors, to make a tender offer or otherwise acquire substantial amounts of our common stock or to launch other takeover attempts that a stockholder might consider to be in such stockholder's best interest.

We may be able to incur substantially more indebtedness, which may increase the risks created by our indebtedness.

The terms of the indentures governing our debt securities do not fully prohibit us or our subsidiaries from incurring additional indebtedness. If we are in compliance with the financial covenants set forth in our revolving credit agreements and the indentures governing our debt securities, we may be able to incur substantial additional indebtedness. If we incur additional indebtedness, the related risks that we now face may intensify.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships or limit our ability to obtain financing on favorable terms.

We cannot assure you that any of our current credit ratings or the ratings of our subsidiaries will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Our ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with our credit facilities could cause annual fees and borrowing rates to increase if an adverse rating impact occurs. The impact of any future downgrade could include an increase in the costs of our short-term borrowings, but a reduction in our credit ratings would not result in any defaults or accelerations. Any future downgrade could also lead to higher long-term borrowing costs and, if below investment grade, would require us to post collateral or letters of credit.

Our debt levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities.

We have revolving credit agreements for working capital, capital expenditures, acquisitions and other corporate purposes. The levels of our debt could have important consequences, including the following:

- the ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or the financing may not be available on favorable terms;
- a portion of cash flows will be required to make interest payments on the debt, reducing the funds that would otherwise be available for operations and future business opportunities; and
- our debt levels may limit our flexibility in responding to changing business and economic conditions.

We are exposed to the credit risk of our key customers and counterparties, and any material nonpayment or nonperformance by our key customers and counterparties could adversely affect our consolidated financial position, results of operations and cash flows.

We are exposed to credit risks in our generation, retail distribution and pipeline operations. Credit risk includes the risk that counterparties who owe us money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and we could incur losses.

RISKS ASSOCIATED WITH OUR INVESTMENT IN ENABLE MIDSTREAM PARTNERS

The Company does not control Enable and therefore is not able to cause or prevent certain actions by Enable. The general partnership of Enable is equally controlled by the Company and CenterPoint.

Enable has its own governing board; therefore, the Company is not able to exercise control over Enable. Accordingly, the Company is unable to cause or prevent certain actions by Enable. Further, the Company cannot control the actions of the other general partner, CenterPoint. Our interests may not align with those of CenterPoint, and this lack of control could adversely impact our investment in Enable.

A portion of our earnings and operating cash flows are based on the performance of Enable. If any of the following risks were to occur, our business, financial condition, results of operations or cash flows could be materially adversely affected.

Our operating cash flow is derived partially from cash distributions we receive from Enable.

Our operating cash flow is derived partially from cash distributions we receive from Enable. The amount of cash Enable can distribute on its units principally depends upon the amount of cash generated from its operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees and gross margins it realizes with respect to the volume of natural gas, NGLs and crude oil that it handles;
- the prices of, levels of production of, and demand for natural gas, NGLs and crude oil;
- the volume of natural gas, NGLs and crude oil it gathers, compresses, treats, dehydrates, processes, fractionates, transports and stores;
- the relationship among prices for natural gas, NGLs and crude oil;
- cash calls and settlements of hedging positions;
- margin requirements on open price risk management assets and liabilities;
- the level of competition from other companies offering midstream services;
- adverse effects of governmental and environmental regulation;
- the level of its operation and maintenance expenses and general and administrative costs; and
- prevailing economic conditions.

In addition, the actual amount of cash Enable will have available for distribution will depend on other factors, including:

- the level and timing of capital expenditures it makes;
- the cost of acquisitions;
- its debt service requirements and other liabilities;
- fluctuations in working capital needs;
- its ability to borrow funds and access capital markets;
- restrictions contained in its debt agreements;
- the amount of cash reserves established by its general partner;
- distributions paid on its Series A Preferred Units; and
- other business risks affecting its cash levels.

Enable's contracts are subject to renewal risk.

As contracts with Enable's existing suppliers and customers expire, Enable negotiates extensions or renewals of those contracts or enter into new contracts with other suppliers and customers. Enable may be unable to extend or renew existing contracts or enter into new contracts on favorable commercial terms, if at all. Depending on prevailing market conditions at the time of an extension or renewal, gathering and processing customers with fee-based contracts may desire to enter into contracts under different fee arrangements, and gathering and processing customers with contracts that contain minimum volume

commitments may desire to enter into contracts without minimum volume commitments. Likewise, Enable's transportation and storage customers may choose not to extend or renew expiring contracts based on the economics of the related areas of production. To the extent Enable is unable to renew or replace its expiring contracts on terms that are favorable to Enable, if at all, or successfully manage its overall contract mix over time, its financial position, results of operations and ability to make cash distributions to unitholders, including us, could be adversely affected.

Enable depends on a small number of customers for a significant portion of its gathering and processing revenues and its transportation and storage revenues. The loss of, or reduction in volumes from, these customers could result in a decline in sales of its gathering and processing or transportation and storage services and adversely affect its financial position, results of operations and ability to make cash distributions to us.

For the year ended December 31, 2017, 57 percent of Enable's gathered natural gas volumes were attributable to the affiliates of Continental Resources, Inc., Vine Oil and Gas, GeoSouthern Energy Corporation, XTO Energy Inc. and Tapstone Corporation and 51 percent of its transportation and storage service revenues were attributable to affiliates of CenterPoint, Spire Inc., American Electric Power Co., the Company and Continental Resources, Inc. The loss of all or even a portion of the gathering and processing or transportation and storage services for any of these customers, the failure to extend or replace these contracts or the extension or replacement of these contracts on less favorable terms, as a result of competition or otherwise, could adversely affect Enable's financial position, results of operations and ability to make cash distributions to unitholders, including us.

As further discussed in "Natural Gas Midstream Operations - Enable Midstream Partners" in "Item 1. Business," in 2017, Spire Inc. disclosed its plan to construct additional interstate pipeline serving the St. Louis, Missouri market, subject to receiving FERC approval. If Spire Inc. constructs this pipeline, Enable anticipates that Spire Inc.'s need for firm transportation and storage capacity on Enable's pipelines will decrease.

The businesses of Enable are dependent, in part, on the drilling and production decisions of others.

The businesses of Enable are dependent on the drilling and production of natural gas and crude oil. Enable has no control over the level of drilling activity in its areas of operation, or the amount of natural gas, NGL and crude oil reserves associated with wells connected to its systems. In addition, as the rate at which production from wells currently connected to its system naturally declines over time, its gross margin associated with those wells will also decline. To maintain or increase throughput levels on its gathering and transportation systems and the asset utilization rates at its natural gas processing plants, its customers must continually obtain new natural gas, NGL and crude oil supplies. The primary factors affecting its ability to obtain new supplies of natural gas, NGLs and crude oil and attract new customers to its assets are the level of successful drilling activity near its systems, its ability to compete for volumes from successful new wells and its ability to expand its capacity as needed. If Enable is not able to obtain new supplies of natural gas and crude oil to replace the natural decline in volumes from existing wells, throughput on its gathering, processing, transportation and storage facilities would decline, which could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us. Enable has no control over producers or their drilling and production decisions, which are affected by, among other things:

- the availability and cost of capital;
- prevailing and projected commodity prices, including the prices of natural gas, NGLs and crude oil;
- demand for natural gas, NGLs and crude oil;
- levels of reserves;
- geological considerations;
- environmental or other governmental regulations, including the availability of drilling permits and the regulation of hydraulic fracturing; and
- the availability of drilling rigs and other costs of production and equipment.

Fluctuations in energy prices can also greatly affect the development of new natural gas, NGL and crude oil reserves. Drilling and production activity generally decreases as commodity prices decrease. In general terms, the prices of natural gas, NGLs, crude oil and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond its control. Because of these and other factors, even if new reserves are known to exist in areas served by Enable's assets, producers may choose not to develop those reserves. Declines in natural gas, NGL or crude oil prices can have a negative impact on exploration, development and production activity and, if sustained, could lead to decreases in such activity. Sustained low natural gas, NGL or crude oil prices could also lead producers to shut in production from their existing wells. Sustained reductions in exploration or production activity in its areas of operation could lead to further reductions in the utilization of its systems, which could adversely affect its financial position, results of operations and ability to make cash distributions to its unitholders, including us.

In addition, it may be more difficult to maintain or increase the current volumes on its gathering systems and its processing plants, as several of the formations in the unconventional resource plays in which Enable operates generally have higher initial production rates and steeper production decline curves than wells in more conventional basins. Should Enable determine that the economics of its gathering assets do not justify the capital expenditures needed to grow or maintain volumes associated therewith, it may reduce such capital expenditures, which could cause revenues associated with these assets to decline over time.

Enable's industry is highly competitive, and increased competitive pressure could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us.

Enable competes with similar enterprises in its respective areas of operation. The principal elements of competition are rates, terms of service and flexibility and reliability of service. Competitors include large energy companies that have greater financial resources and access to supplies of natural gas, NGLs and crude oil other than Enable. Some of these competitors may expand or construct gathering, processing, transportation and storage systems that would create additional competition for the services Enable provides to its customers. Excess pipeline capacity in the regions served by Enable's interstate pipelines could also increase competition and adversely impact the ability to renew or enter into new contracts with respect to available capacity when existing contracts expire. In addition, customers that are significant producers of natural gas or crude oil may develop their own gathering, processing, transportation and storage systems in lieu of using Enable. Enable's ability to renew or replace existing contracts with customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of its competitors and customers. Further, natural gas utilized as a fuel competes with other forms of energy available to end-users, including electricity, coal and liquid fuels. Increased demand for such forms of energy at the expense of natural gas could lead to a reduction in demand for natural gas gathering, processing, transportation and storage services. All of these competitive pressures could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us.

Enable derives a substantial portion of its gross margin from subsidiaries through which it holds a substantial portion of its assets.

Enable derives a substantial portion of its gross margin from, and holds a substantial portion of its assets through, its subsidiaries. As a result, it depends on distributions from its subsidiaries in order to meet its payment obligations. In general, these subsidiaries are separate and distinct legal entities and have no obligation to provide Enable with funds for its payment obligations, whether by dividends, distributions, loans or otherwise. In addition, provisions of applicable law, such as those limiting the legal sources of dividends, limit its subsidiaries' ability to make payments or other distributions, and its subsidiaries could agree to contractual restrictions on its ability to make distributions.

The right by Enable to receive any assets of any subsidiary, and therefore the right of its creditors to participate in those assets, will be effectively subordinated to the claims of that subsidiary's creditors, including trade creditors. In addition, even if Enable were a creditor of any subsidiary, its rights as a creditor would be subordinated to any security interest in the assets of that subsidiary and any indebtedness of the subsidiary senior to that held by them.

The amount of cash Enable has available for distribution to its limited partners depends primarily on its cash flow rather than on its profitability, which may prevent Enable from making distributions, even during periods in which it records net income.

The amount of cash Enable has available for distribution depends primarily upon its cash flow rather than on profitability. Profitability is affected by non-cash items but cash flow is not. As a result, Enable may make cash distributions during periods when it records losses for financial accounting purposes and may not make cash distributions during periods when it records net earnings for financial accounting purposes.

Enable may not be able to recover the costs of its substantial planned investment in capital improvements and additions, and the actual cost of such improvements and additions may be significantly higher than it anticipates.

Enable's business plan calls for investments in capital improvements and additions. Capital expenditures could range from approximately $450 million to $600 million for the year ending December 31, 2018.

The construction of additions or modifications to Enable's existing systems, and the construction of new midstream assets, involves numerous regulatory, environmental, political and legal uncertainties, many of which are beyond its control and may require the expenditure of significant amounts of capital, which may exceed estimates. These projects may not be completed at the planned cost, on schedule or at all. The construction of new pipeline, gathering, treating, processing, compression or other facilities is subject to construction cost overruns due to labor costs, costs and availability of equipment and materials such as steel,

labor shortages or weather or other delays, inflation or other factors, which could be material. In addition, the construction of these facilities is typically subject to the receipt of approvals and permits from various regulatory agencies. Those agencies may not approve the projects in a timely manner, if at all, or may impose restrictions or conditions on the projects that could potentially prevent a project from proceeding, lengthen its expected completion schedule and/or increase its anticipated cost. Moreover, revenues and cash flows may not increase immediately upon the expenditure of funds on a particular project. For instance, if an existing pipeline is expanded or a new pipeline is constructed, the construction may occur over an extended period of time, and Enable may not receive any material increases in revenues or cash flows until the project is completed. In addition, Enable may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. As a result, the new facilities may not be able to achieve an expected investment return, which could adversely affect its financial position, results of operations and ability to make cash distributions to its unitholders, including us.

In connection with its capital investments, Enable may engage a third party to estimate potential reserves in areas to be developed prior to constructing facilities in those areas. To the extent Enable relies on estimates of future production in deciding to construct additions to its systems, those estimates may prove to be inaccurate either in volume or timing due to numerous uncertainties inherent in estimating future production. To the extent estimates of the volume of new production are inaccurate, new facilities may not be able to attract sufficient throughput to achieve expected investment return, which could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us. To the extent estimates in the timing of new production are inaccurate, new facilities may be constructed in advance of the actual need for capacity or may not be constructed in time to accommodate volume flows, which could adversely affect Enable's financial position, results of operations and ability to make cash distributions to unitholders, including us. In addition, the construction of additions to existing gathering and transportation assets may require new rights-of-way prior to construction. Those rights-of-way to connect new natural gas supplies to existing gathering lines may be unavailable, and it may not be able to capitalize on attractive expansion opportunities. Additionally, it may become more expensive to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, its financial position, results of operations and ability to make cash distributions to unitholders, including us, could be adversely affected.

Natural gas, NGL and crude oil prices are volatile, and changes in these prices could adversely affect Enable's financial position, results of operations and its ability to make cash distributions to unitholders, including us.

Enable's financial position, results of operations and ability to make cash distributions to us could be negatively affected by adverse changes in the prices of natural gas, NGLs and crude oil depending on factors that are beyond its control. These factors include demand for these commodities, which fluctuates with changes in market and economic conditions and other factors, including the impact of seasonality and weather, general economic conditions, the level of domestic and offshore natural gas production and consumption, the availability of imported natural gas, liquefied natural gas, NGLs and crude oil, actions taken by foreign natural gas and oil producing nations, the availability of local, intrastate and interstate transportation systems, the availability and marketing of competitive fuels, the impact of energy conservation efforts, technological advances affecting energy consumption and the extent of governmental regulation and taxation.

Enable's natural gas processing arrangements exposes Enable to commodity price fluctuations. In 2017, seven percent, 35 percent and 58 percent of Enable's processing plant inlet volumes consisted of keep-whole arrangements, percent-of-proceeds or percent-of-liquids and fee-based, respectively. If the price at which Enable sells natural gas or NGLs is less than the cost at which it purchases natural gas or NGLs under these arrangements, then its financial position, results of operations and ability to make cash distributions to unitholders, including us, could be adversely affected.

At any given time, Enable's overall portfolio of processing contracts may reflect a net short position in natural gas (meaning that it is a net buyer of natural gas) and a net long position in NGLs (meaning that it is a net seller of NGLs). As a result, Enable's financial position, results of operations and ability to make cash distributions to unitholders, including us, could be adversely affected to the extent the price of NGLs decreases in relation to the price of natural gas.

Enable's exposure to credit risks of its customers, and any material nonpayment or nonperformance by its customers could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us.

Some of Enable's customers may experience financial problems that could have a significant effect on its customers' creditworthiness. Severe financial problems encountered by its customers could limit Enable's ability to collect amounts owed to it, or to enforce performance of obligations under contractual arrangements. In addition, many of Enable's customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction of its customers' liquidity and limit its customers' ability to make payments or perform on obligations to Enable. Furthermore, some of Enable's customers may be highly

leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to Enable. Financial problems experienced by its customers could result in the impairment of its assets, reduction of its operating cash flows and may also reduce or curtail its customers' future use of its products and services, which could reduce revenues.

Enable provides certain transportation and storage services under fixed-price "negotiated rate" contracts that are not subject to adjustment, even if the cost to perform such services exceeds the revenues received from such contracts, and, as a result, costs could exceed revenues received under such contracts.

Enable has been authorized by the FERC to provide transportation and storage services at its facilities at negotiated rates.

As of December 31, 2017, approximately 44 percent of Enable's aggregate contracted firm transportation firm capacity on EGT and MRT and 44 percent of its aggregate contracted firm storage capacity on EGT and MRT was subscribed under such "negotiated rate" contracts. These contracts generally do not include provisions allowing for adjustment for increased costs due to inflation, pipeline safety activities or other factors that are not tied to an applicable tracking mechanism authorized by the FERC. Successful recovery of any shortfall of revenue, representing the difference between "recourse rates" (if higher) and negotiated rates, is not assured under current FERC policies. If Enable's costs increase and it is not able to recover any shortfall of revenue associated with its negotiated rate contracts, the cash flow realized by its systems could decrease and, therefore, the cash Enable has available for distribution to its unitholders, including us, could also decrease.

If third-party pipelines and other facilities interconnected to Enable's gathering, processing or transportation facilities become partially or fully unavailable to Enable for any reason, Enable's financial position, results of operations and its ability to make cash distributions to us could be adversely affected.

Enable depends upon third-party pipelines to deliver natural gas to, and take natural gas from, its natural gas transportation systems and upon third party pipelines to take crude oil from its crude oil gathering. It also depends on third-party facilities to transport and fractionate NGLs that are delivered to the third party at the tailgates of its processing plants. Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. For example, an outage or disruption on certain pipelines or fractionators operated by a third party could result in the shutdown of certain of its processing plants and gathering systems, and a prolonged outage or disruption could ultimately result in a reduction in the volume of NGLs it is able to produce. Additionally, Enable depends on third parties to provide electricity for compression at many of its facilities. Since it does not own or operate any of these third-party pipelines or other facilities, continuing operation of those facilities is not within its control. If any of these third-party pipelines or other facilities become partially or fully unavailable to Enable for any reason, its financial position, results of operations and ability to make cash distributions to us could be adversely affected.

Enable does not own all of the land on which its pipelines and facilities are located, which could disrupt its operations.

Enable does not own all of the land on which its pipelines and facilities have been constructed, and it is therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if it does not have valid rights-of-way or if such rights-of-way lapse or terminate. Enable may obtain the rights to construct and operate its pipelines for a specific period of time on lands owned by governmental agencies, American Indian tribes or other third parties, including on American Indian allotments, title to which is held in trust by the U.S. A loss of these rights, through its inability to renew right-of-way contracts or otherwise, could cause a cease in operations temporarily or permanently on the affected land, increase costs related to the construction and continuing operations elsewhere, and adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us.

Enable conducts a portion of its operations through joint ventures, which subjects them to additional risks that could adversely affect the success of its operations and financial position, results of operations and ability to make cash distributions to unitholders, including us.

Enable conducts a portion of its operations through joint ventures with third parties, including Spectra Energy Partners, LP, DCP Midstream Partners, LP, Trans Louisiana Gas Pipeline, Inc. and Pablo Gathering, LLC. It may also enter into other joint venture arrangements in the future. These third parties may have obligations that are important to the success of the joint venture, such as the obligation to pay their share of capital and other costs of the joint venture. The performance of these third-party obligations, including the ability of the third parties to satisfy their obligations under these arrangements, is outside the control of Enable. If these parties do not satisfy their obligations under these arrangements, Enable's business may be adversely affected.

The joint venture arrangements of Enable may involve risks not otherwise present when operating assets directly, including, for example:

- joint venture partners may share certain approval rights over major decisions;
- joint venture partners may not pay their share of the obligations, leaving Enable liable for the liabilities created as a result of those unpaid obligations;
- possible inability to control the amount of cash it will receive from the joint venture;
- it may incur liabilities as a result of an action taken by its joint venture partners;
- it may be required to devote significant management time to the requirements of and matters relating to the joint ventures;
- its insurance policies may not fully cover loss or damage incurred by both them and its joint venture partners in certain circumstances;
- its joint venture partners may be in a position to take actions contrary to its instructions or requests or contrary to its policies or objectives; and
- disputes between them and its joint venture partners may result in delays, litigation or operational impasses.

The risks described above or the failure to continue joint ventures or to resolve disagreements with joint venture partners could adversely affect Enable's ability to transact the business that is the subject of such joint venture, which would in turn adversely affect its financial position and results of operations ability to make cash distributions to unitholders, including us. The agreements under which certain joint ventures were formed may subject them to various risks, limit the actions it may take with respect to the assets subject to the joint venture and require them to grant rights to its joint venture partners that could limit its ability to benefit fully from future positive developments. Some joint ventures require Enable to make significant capital expenditures. If it does not timely meet its financial commitments or otherwise do not comply with its joint venture agreements, its rights to participate, exercise operator rights or otherwise influence or benefit from the joint venture may be adversely affected. Certain of its joint venture partners may have substantially greater financial resources than Enable has and it may not be able to secure the funding necessary to participate in operations its joint venture partners propose, thereby reducing its ability to benefit from the joint venture.

Under certain circumstances, Spectra Energy Partners, LP could have the right to purchase an ownership interest in SESH at fair market value.

Enable owns a 50 percent ownership interest in SESH. The remaining 50 percent ownership interests are held by Spectra Energy Partners, LP.

CenterPoint owns a 54.1 percent of Enable's common units, 100.0 percent of its Series A Preferred Units and a 40 percent economic interest in Enable GP, LLC. Pursuant to the terms of the limited liability company agreement of SESH, as amended (the SESH LLC Agreement), if, at any time, CenterPoint has a right to receive less than 50 percent of Enable's distributions through its interests in Enable and in the general partner, or does not have the ability to exercise certain control rights, Spectra Energy Partners, LP could have the right to purchase Enable's interest in SESH at fair market value, subject to certain exceptions.

An impairment of long-lived assets, including intangible assets, equity method investments or goodwill could reduce Enable's earnings.

Long-lived assets, including intangible assets with finite useful lives and property, plant and equipment, are evaluated for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment of long-lived assets is recognized if the carrying amount is not recoverable and exceeds fair value. For example, Enable recorded aggregate impairments for its Service Star business line of $38 million during the years ended December 31, 2016, 2015, 2014 and 2013, a $25 million impairment of its Atoka assets in its gathering and processing segment during the year ended December 31, 2015, and a $12 million impairment of jurisdictional pipelines in its transportation and storage segment during the year ended December 31, 2015.

Equity method investments are evaluated for impairment when events or circumstances indicate that the carrying value of the investment might not be recoverable. An impairment of an equity method investment is recognized if the fair value of the investment as a whole, and not the underlying assets, has declined and the decline is other than temporary. An example of an investment that Enable accounts for under the equity method is its investment in SESH. If Enable enters into additional joint ventures, it could have additional equity method investments.

Goodwill is evaluated for impairment on an annual basis as well as when events or circumstances change that would more likely than not reduce the fair value of a reporting unit is below its carrying amount. An impairment of goodwill is recognized if the carrying value of a reporting unit exceeds its fair value and the carrying amount of that reporting unit’s goodwill exceeds

the implied value of that goodwill. For example, Enable recorded impairments to goodwill of $1.087 billion during the year ended December 31, 2015. As a result, there was no goodwill recorded as of December 31, 2016 and 2015. As of December 31, 2017, Enable has goodwill of $12 million as a result of the acquisition of Align Midstream, LLC in the fourth quarter of 2017.

Enable could experience future events or circumstances that result in an impairment of long-lived assets, including intangible assets, equity method investments, or goodwill. If Enable recognizes an impairment, it would take an immediate non-cash charge to earnings with a correlative effect on equity and balance sheet leverage as measured by debt to total capitalization. As a result, an impairment could have an adverse effect on Enable's results of operations and its ability to satisfy the financial ratios or other covenants under its existing or future debt agreements.

Enable's business involves many hazards and operational risks, some of which may not be fully covered by insurance. Insufficient insurance coverage and increased insurance costs could adversely affect its financial position, results of operations or ability to make cash distributions to us.

Enable's operations are subject to all of the risks and hazards inherent in the gathering, processing, transportation and storage of natural gas and crude oil, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires, earthquakes and other natural disasters, acts of terrorism and actions by third parties;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- leaks of natural gas, NGLs, crude oil and other hydrocarbons or losses of natural gas, NGLs and crude oil as a result of the malfunction of equipment or facilities;
- ruptures, fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury or loss of life, severe damage to and destruction of property, plant and equipment and pollution or other environmental damage. These risks may also result in curtailment or suspension of its operations. A natural disaster or other hazard affecting the areas in which it operates could adversely affect Enable's results of operations. Enable is not fully insured against all risks inherent in its business. Enable currently has general liability and property insurance in place to cover certain of its facilities in amounts that it considers appropriate. Such policies are subject to certain limits and deductibles. It does not have business interruption insurance coverage for all of its operations. Insurance coverage may not be available in the future at current costs or on commercially reasonable terms, and the insurance proceeds received for any loss of, or any damage to, any of its facilities may not be sufficient to restore the loss or damage without negative impact on its results of operations and ability to make cash distributions to its unitholders, including us.

The use of derivative contracts by Enable and its subsidiaries in the normal course of business could result in financial losses that could adversely affect its financial position, results of operations and its ability to make cash distributions to unitholders, including us.

Enable and its subsidiaries periodically use derivative instruments, such as swaps, options, futures and forwards, to manage its commodity and financial market risks. Enable and its subsidiaries could recognize financial losses as a result of volatility in the market values of these contracts, or should a counterparty fail to perform. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management’s judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Failure to attract and retain an appropriately qualified workforce could adversely impact Enable's results of operations.

Enable's business is dependent on its ability to recruit, retain and motivate employees. Certain circumstances, such as an aging workforce without appropriate replacements, a mismatch of existing skill sets to future needs, competition for skilled labor or the unavailability of contract resources may lead to operating challenges such as a lack of resources, loss of knowledge or a lengthy time period associated with skill development. Enable's costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect Enable's ability to manage and operate its business. If Enable is unable to successfully attract and retain an appropriately qualified workforce, its results of operations could be negatively affected.

Enable has 140 employees who are participants under OGE Energy Corp.'s defined benefit and retiree medical plans, who are seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy Corp. If seconding is terminated, employees of OGE Energy Corp. that Enable determines to hire are under no obligation to accept Enable's offer of employment on the terms Enable provides, or at all.

Enable's ability to grow is dependent on its ability to access external financing sources.

Enable expects its operating subsidiaries will distribute all of their available cash to Enable and that it will distribute all of its available cash to its unitholders. As a result, Enable expects that it and its operating subsidiaries will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund acquisitions and expansion capital expenditures. As a result, to the extent Enable or its operating subsidiaries are unable to finance growth externally, its operating subsidiaries' cash distribution policy will significantly impair its operating subsidiaries' ability to grow. In addition, because it and its operating subsidiaries distribute all available cash, its operating subsidiaries' growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations.

To the extent Enable issues additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk it will be unable to maintain or increase its per unit distribution level, which in turn may impact the available cash that Enable has to distribute on each unit. There are no limitations in the partnership agreement on its ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt by Enable or its operating subsidiaries to finance its growth strategy would result in increased interest expense, which in turn may negatively impact the available cash that its operating subsidiaries have to distribute to it, and thus that it has to distribute to its unitholders, including us.

Enable depends on access to the capital markets to fund its expansion capital expenditures. Historically, unit prices of midstream master limited partnerships have experienced periods of volatility. In addition, because Enable's common units are yield-based securities, rising market interest rates could impact the relative attractiveness of its common units to investors. As a result of capital market volatility, Enable may be unable to issue equity or debt on satisfactory terms, or at all, which may limit its ability to expand its operations or make future acquisitions.

CenterPoint Energy, Inc. has publicly disclosed that it is evaluating strategic alternatives for its investment in Enable. CenterPoint Energy, Inc. has disclosed that the alternatives may include a sale of all or a portion of the interests that it owns in Enable and the general partner of Enable, that if the sale option is not viable, it intends to reduce its ownership in Enable over time through a sale of the common units it holds in the public equity markets subject to market conditions, and that there can be no assurances that these evaluations will result in any specific action. CenterPoint Energy Inc.'s disclosure, as well as any sales by CenterPoint of the common units it holds in the public equity markets, could have an adverse impact on the market for Enable common units, including Enable's ability to issue equity on favorable terms to fund Enable's capital needs or at all.

Enable's merger and acquisition activities may not be successful or may result in completed acquisitions that do not perform as anticipated, which could adversely affect its financial position, results of operations or future growth.

From time to time, Enable has made, and it intends to continue to make, acquisitions of businesses and assets. Such acquisitions involve substantial risks, including the following:

- acquired businesses or assets may not produce revenues, earnings or cash flow at anticipated levels;
- acquired businesses or assets could have environmental, permitting or other problems for which contractual protections prove inadequate;
- it may assume liabilities that were not disclosed to it, that exceed its estimates, or for which its rights to indemnification from the seller are limited;
- it may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems; and
- acquisitions, or the pursuit of acquisitions, could disrupt its ongoing businesses, distract management, divert resources and make it difficult to maintain its current business standards, controls and procedures.

In addition, Enable's growth strategy includes, in part, the ability to make acquisitions on economically acceptable terms. If Enable is unable to make acquisitions or if its acquisitions do not perform as anticipated, Enable's future growth may be adversely affected.

Enable and its operating subsidiaries' debt levels may limit its flexibility in obtaining additional financing and in pursuing other business opportunities.

As of December 31, 2017, Enable had approximately $2.6 billion of long-term debt outstanding, excluding the premiums on senior notes. In addition, as of December 31, 2017, Enable had $405.0 million outstanding under its commercial paper program and $450.0 million outstanding under its 2015 term loan agreement. Enable also has a $1.75 billion revolving credit facility for working capital, capital expenditures and other partnership purposes, including acquisitions, of which $1.3 billion was available as of February 1, 2018. Enable has the ability to incur additional debt, subject to limitations in its credit facilities. The levels of debt could have important consequences, including the following:

- the ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or the financing may not be available on favorable terms, if at all;
- a portion of cash flows will be required to make interest payments on the debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions;
- the debt level will make Enable more vulnerable to competitive pressures or a downturn in the business or the economy generally; and
- the debt level may limit flexibility in responding to changing business and economic conditions.

Enable's and its operating subsidiaries' ability to service its debt will depend upon, among other things, its future financial and operating performance, which will be affected by prevailing economic conditions, commodity prices and financial, business, regulatory and other factors, some of which are beyond its control. If operating results are not sufficient to service its operating subsidiaries' current or future indebtedness, it and its subsidiaries may be forced to take actions such as reducing distributions, reducing or delaying business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing debt, or seeking additional equity capital. These actions may not be effected on satisfactory terms, or at all.

Enable's credit facilities contain operating and financial restrictions, including covenants and restrictions that may be affected by events beyond its control, which could adversely affect its financial condition, results of operations and ability to make cash distributions to its unitholders, including us.

Enable's credit facilities contain customary covenants that, among other things, limit the ability to:

- permit its subsidiaries to incur or guarantee additional debt;
- incur or permit to exist certain liens on assets;
- dispose of assets;
- merge or consolidate with another company or engage in a change of control;
- enter into transactions with affiliates on non-arm's length terms; and
- change the nature of its business.

Enable's credit facilities also require it to maintain certain financial ratios. Its ability to meet those financial ratios can be affected by events beyond its control, and assurance it will meet those ratios cannot be guaranteed. In addition, its credit facilities contain events of default customary for agreements of this nature.

Enable's ability to comply with the covenants and restrictions contained in its credit facilities may be affected by events beyond its control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, its ability to comply with these covenants may be impaired. If any of the restrictions, covenants, ratios or tests in its credit facilities is violated, a significant portion of its indebtedness may become immediately due and payable. In addition, its lenders' commitments to make further loans to Enable under the revolving credit facility may be suspended or terminated. Enable might not have, or be able to obtain, sufficient funds to make these accelerated payments.

Affiliates of Enable's general partner, including CenterPoint and the Company, may compete with Enable, and neither the general partner nor its affiliates have any obligation to present business opportunities to Enable.

Under Enable's omnibus agreement, both CenterPoint and the Company are prohibited from, directly or indirectly, owning, operating, acquiring or investing in any business engaged in midstream operations located within the U.S., other than through Enable. This requirement applies to both CenterPoint and the Company for so long as either CenterPoint or the Company holds any interest in Enable's general partner or at least 20 percent of its common units. However, if CenterPoint or the Company acquires any business with midstream operations assets that have a value in excess of $50.0 million (or $100.0 million in the aggregate with such party's other acquired midstream operations assets that have not been offered to Enable), the acquiring party

will be required to offer to Enable such assets for such value. If Enable does not purchase such assets, the acquiring party will be free to retain and operate such midstream assets, so long as the value of the assets does not reach certain thresholds.

As a result, under the circumstances described above, CenterPoint and the Company have the ability to construct or acquire assets that directly compete with Enable's assets. Pursuant to the terms of Enable's partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to Enable's general partner or any of its affiliates, including its executive officers and directors and CenterPoint and the Company. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for Enable will not have any duty to communicate or offer such opportunity to Enable. Any such person or entity will not be liable to Enable or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to Enable. This may create actual and potential conflicts of interest between Enable and affiliates of its general partner and result in less than favorable treatment of Enable and its common unitholders.

If Enable fails to maintain an effective system of internal controls, then it may not be able to accurately report financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in its financial reporting, which would harm Enable's business and the trading price of its common units.

Effective internal controls are necessary for Enable to provide reliable financial reports, prevent fraud and operate successfully as a public company. If its efforts to maintain an effective system of internal controls are not successful, it will be unable to maintain adequate controls over its financial processes and reporting in the future and its operating results could be harmed or fail to meet its reporting obligations. Ineffective internal controls also could cause investors to lose confidence in its reported financial information, which would likely have a negative effect on the trading price of Enable's common units.

Cybersecurity attacks or other disruptions of Enable's systems, networks and technology could adversely impact Enable's financial position, results of operations and ability to make cash distributions to unitholders, including us.

Enable has become increasingly dependent on the systems, networks and technology that it uses to conduct almost all aspects of its business, including the operation of its gathering, processing, transportation and storage assets, the recording of commercial transactions and the reporting of financial information. Enable depends on both its own systems, networks and technology as well as the systems, networks and technology of its vendors, customers and other business partners. Any disruption of these systems, networks and technology could disrupt the operation of Enable's business. Disruptions can result from a variety of causes, including natural disasters, the failure of software or equipment and manmade events, such as cybersecurity attacks or information security breaches. Cybersecurity attacks and information security breaches could result in the unauthorized use of confidential, proprietary or other information and in the disruption of Enable's critical business functions and operations, adversely affecting its reputation and subjecting it to possible legal claims and liability. In addition, Enable is not fully insured against all cybersecurity risks.

Terrorist attacks or other physical security threats could adversely affect Enable's business.

Enable's gathering, processing, transportation and storage assets may be targets of terrorist activities or other physical security threats that could disrupt its ability to conduct its business. It is possible that any of these occurrences, or a combination of them, could adversely affect Enable's financial position, results of operations and ability to make cash distributions to unitholders, including us. In addition, any physical damage to Enable's assets resulting from acts of terrorism may not be fully covered by Enable's insurance.

Enable may be unable to obtain or renew permits necessary for its operations, which could inhibit its ability to do business.

Performance of its operations require it obtain and maintain a number of federal and state permits, licenses and approvals with terms and conditions containing a significant number of prescriptive limits and performance standards in order to operate. All of these permits, licenses, approval limits and standards require a significant amount of monitoring, record keeping and reporting in order to demonstrate compliance with the underlying permit, license, approval limit or standard. Noncompliance or incomplete documentation of Enable's compliance status may result in the imposition of fines, penalties and injunctive relief. A decision by a government agency to deny or delay the issuance of a new or existing material permit or other approval, or to revoke or substantially modify an existing permit or other approval, could adversely affect its ability to initiate or continue operations at the affected location or facility and on its financial condition, results of operations and ability to make cash distributions to unitholders, including us.

Additionally, in order to obtain permits and renewals of permits and other approvals in the future, Enable may be required to prepare and present data to governmental authorities pertaining to the potential adverse impact that any proposed pipeline or processing-related activities may have on the environment, individually or in the aggregate, including on public and Indian lands. Certain approval procedures may require preparation of archaeological surveys, endangered species studies and other studies to assess the environmental impact of new sites or the expansion of existing sites. Compliance with these regulatory requirements is expensive and significantly lengthens the time required to prepare applications and to receive authorizations.

Costs of compliance with existing environmental laws and regulations are significant, and the cost of compliance with future environmental laws and regulations may adversely affect Enable's financial position, results of operations and its ability to make cash distributions to unitholders, including us.

Enable is subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, wildlife conservation, natural resources and health and safety that could, among other things, delay or increase costs of construction, restrict or limit the output of certain facilities and/or require additional pollution control equipment and otherwise increase costs. For instance, in May 2016, the EPA issued final standards governing methane emissions imposing more stringent controls on methane and volatile organic compounds emissions at new and modified oil and natural gas production, processing, storage and transmission facilities. These rules have required changes to Enable's operations, including the installation of new equipment to control emissions. Additionally, several states are pursuing similar measures to regulate emissions of methane from new and existing sources. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations. Future federal and state regulations relating to Enable's gathering and processing, transmission and storage operations remain a possibility and could result in increased compliance costs on Enable's operations. Furthermore, if new or more stringent federal, state or local legal restrictions are adopted in areas where Enable's oil and natural gas exploration and production customers operate, they could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells, some or all of which could adversely affect demand for Enable's services to those customers.

There is inherent risk of the incurrence of environmental costs and liabilities in Enable's operations due to the handling of natural gas, NGLs, crude oil and produced water as well as air emissions related to its operations and historical industry operations and waste disposal practices. These matters are subject to stringent and complex federal, state and local laws and regulations governing environmental protection, including the discharge of materials into the environment and the protection of plants, wildlife, and natural and cultural resources. These laws and regulations can restrict or impact business activities in many ways, such as restricting the handling or disposing of wastes or requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators. Joint and several strict liability may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of wastes on, under or from its properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under its control. Private parties, including the owners of the properties through which its gathering and transportation systems pass and facilities where its wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non- compliance, with environmental laws and regulations or for personal injury or property damage. For example, an accidental release from one of its pipelines could subject them to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. Enable may be unable to recover these costs from insurance. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase compliance costs and the cost of any remediation that may become necessary. Further, stricter requirements could negatively impact its customers' production and operations, resulting in less demand for its services.

Increased regulation of hydraulic fracturing and waste water injection wells could result in reductions or delays in natural gas production by Enable's customers, which could adversely affect its financial position, results of operations and ability to make cash distributions to its unitholders, including us.

Hydraulic fracturing is a common practice that is used by many of Enable's customers to stimulate production of natural gas and crude oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing typically is regulated by state oil and natural gas commissions. In addition, certain federal agencies have proposed additional laws and regulations to more closely regulate the hydraulic fracturing process. In past sessions, Congress has considered, but not passed, legislation to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. The EPA has issued Safe Drinking Water Act permitting guidance for hydraulic fracturing operations involving the use of diesel fuel in fracturing fluids in those states where the EPA is the permitting authority.

Some states have adopted, and other states have considered adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular, in some cases banning hydraulic fracturing entirely. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where Enable's oil and natural gas exploration and production customers operate, they could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells, some or all of which activities could adversely affect demand for Enable's services to those customers.

State and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste disposal and seismic activity. Similar concerns have been raised that hydraulic fracturing may also contribute to seismic activity. When caused by human activity, such events are called induced seismicity. In March 2016, the U.S. Geological Survey identified six states with the most significant hazards from induced seismicity, including Oklahoma, Kansas, Texas, Colorado, New Mexico and Arkansas. In March 2017, the U.S. Geological Survey produced an updated seismic hazard survey that forecasted lower earthquake rates in regions of induced activity but still showed significantly elevated hazards in the central and eastern U.S. In light of these concerns, some state regulatory agencies have modified their regulations or issued orders to address induced seismicity. For example, the OCC has implemented volume reduction plans, and at times required shut-ins, for disposal wells injecting wastewater from oil and gas operations into the Arbuckle formation. In December 2016, the OCC also released well completion seismicity guidelines for operators in the South Central Oklahoma Oil Province and the Sooner Trend Anadarko Basin Canadian and Kingfisher Counties that call for hydraulic fracturing operations to be suspended following earthquakes of certain magnitudes in the vicinity. Certain environmental and other groups have also suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process. Enable cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. Increased regulation and attention given to induced seismicity could lead to greater opposition to, and litigation concerning, oil and gas activities utilizing hydraulic fracturing or injection wells for waste disposal. Additional legislation or regulation could also lead to operational delays or increased operating costs for Enable's customers, which in turn could reduce the demand for Enable's services.

Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

Enable may incur substantial liabilities to comply with climate change legislation and regulatory initiatives.

Because Enable's operations emit various types of greenhouse gases, legislation and regulations governing greenhouse gas emissions could increase its costs related to operating and maintaining its facilities, and could delay future permitting. At the federal level, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, require the monitoring and reporting of greenhouse gas emissions from specified onshore and offshore oil and natural gas production sources in the U.S. on an annual basis, which include certain of Enable's operations. Additional rules, such as the updates to the oil and gas new source performance standard requirements finalized by the EPA in May 2016, could affect Enable's ability to obtain air permits for new or modified facilities or require its operations to incur additional expenses to control air emissions by installing emissions control technologies and adhering to a variety of work practice and other requirements. These requirements could increase the costs of development and production, reducing the profits available to Enable and potentially impair its operator’s ability to economically develop its properties.

In addition, the U.S. Congress has in the past and may in the future consider legislation to reduce emissions of greenhouse gases, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. Efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. From time to time, the U.S. Congress has considered adopting legislation to limit greenhouse gases emissions. A number of state and regional efforts have also emerged that are aimed at tracking and/or reducing greenhouse gas emissions by means of cap and trade programs. These programs typically require major sources of greenhouse gas emissions to acquire and surrender emission allowances in return for emitting those greenhouse gas emissions. Any such future laws and regulations imposing reporting obligations on, or limiting emissions of greenhouse gases could require Enable to incur costs to reduce emissions of greenhouse gases. Substantial limitations on greenhouse gas emissions could also adversely affect demand for oil and natural gas. Depending on the particular program, Enable could in the future be required to purchase and surrender emission allowances or otherwise undertake measures to reduce greenhouse gas emissions. Any additional costs or operating restrictions associated with new legislation or regulations regarding

greenhouse gas emissions could adversely affect the demand for Enable's service and its financial position, results of operations and ability to make cash distributions to unitholders, including us.

Increased regulatory-imposed costs may increase the cost of consuming, and thereby reduce demand for, the products that Enable gathers, treats and transports. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this view could negatively affect its ability to access capital markets or cause them to receive less favorable terms and conditions. Consequently, legislation and regulatory initiatives aimed at reducing greenhouse gases could have a material adverse effect on its financial position, results of operations and ability to make cash distributions to its unitholders, including us.

Finally, some scientists have concluded that increasing concentrations of greenhouse gases in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could adversely affect Enable's results of operations.

Enable's operations are subject to extensive regulation by federal regulatory authorities. Changes or additional regulatory measures adopted by such authorities could adversely affect its financial position, results of operations and ability to make cash distributions to its unitholders, including us.

The rates charged by several of Enable's pipeline systems, including interstate gas transportation service provided by its intrastate pipelines, are regulated by the FERC. The FERC and state regulatory agencies also regulate other terms and conditions of the services it may offer. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower its tariff rates or deny any rate increase or other material changes to the types or terms and conditions of service it might propose or offer, the profitability of its pipeline businesses could suffer. If it were permitted to raise its tariff rates for a particular pipeline, there might be significant delay between the time the tariff rate increase is approved and the time that the rate increase actually goes into effect, which could also limit profitability. Furthermore, competition from other pipeline systems may prevent them from raising its tariff rates even if permitted by regulatory agencies. The regulatory agencies that regulate its systems periodically implement new rules, regulations and terms and conditions of services subject to its jurisdiction. New initiatives or orders may adversely affect the rates charged for services or otherwise adversely affect its financial position, results of operations and ability to make cash distributions to its unitholders, including us.

Enable's natural gas interstate pipelines are regulated by the FERC under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. Generally, the FERC's authority over interstate natural gas transportation extends to:

- rates, operating terms, conditions of service and service contracts;
- certification and construction of new facilities;
- extension or abandonment of services and facilities or expansion of existing facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- depreciation and amortization policies;
- conduct and relationship with certain affiliates;
- market manipulation in connection with interstate sales, purchases or natural gas transportation; and
- various other matters.

Should Enable fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, it could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 to impose penalties for current violations of up to $1 million per day for each violation and possible criminal penalties of up to approximately $1.2 million per violation.

The FERC's jurisdiction extends to the certification and construction of interstate transportation and storage facilities, including, but not limited to expansions, lateral and other facilities and abandonment of facilities and services. Prior to commencing construction of significant new interstate transportation and storage facilities, an interstate pipeline must obtain a certificate authorizing the construction, or an order amending its existing certificate, from the FERC. Certain minor expansions are authorized by blanket certificates that the FERC has issued by rule. Typically, a significant expansion project requires review by a number of governmental agencies, including state and local agencies, whose cooperation is important in completing the regulatory process on schedule. Any failure by an agency to issue sufficient authorizations or permits in a timely manner for one or more of these projects may mean that Enable will not be able to pursue these projects or that they will be constructed in a manner or with capital requirements that Enable did not anticipate. Enable's inability to obtain sufficient permits and authorizations in a timely manner could materially and negatively impact the additional revenues expected from these projects.

The FERC conducts audits to verify compliance with the FERC's regulations and the terms of its orders, including whether the websites of interstate pipelines accurately provide information on the operations and availability of services. The FERC's regulations require uniform terms and conditions for service, as set forth in agreements for transportation and storage services executed between interstate pipelines and their customers. These service agreements are required to conform, in all material respects, with the standard form of service agreements set forth in the pipeline's FERC-approved tariff. Non-conforming agreements must be filed with, and accepted by, the FERC. In the event that the FERC finds that an agreement, in whole or part, is materially non-conforming, it could reject the agreement or require Enable to seek modification, or alternatively require Enable to modify its tariff so that the non-conforming provisions are generally available to all customers.

The rates, terms and conditions for transporting natural gas in interstate commerce on certain of Enable's intrastate pipelines and for services offered at certain of Enable's storage facilities are subject to the jurisdiction of the FERC under Section 311 of the Natural Gas Policy Act. Rates to provide such interstate transportation service must be "fair and equitable" under the Natural Gas Policy Act and are subject to review, refund with interest if found not to be fair and equitable, and approval by the FERC at least once every five years.

Enable's crude oil gathering pipelines are subject to common carrier regulation by the FERC under the Interstate Commerce Act. The Interstate Commerce Act requires that Enable maintain tariffs on file with the FERC setting forth the rates Enable charges for providing transportation services, as well as the rules and regulations governing such services. The Interstate Commerce Act requires, among other things, that Enable's rates must be "just and reasonable" and that Enable provide service in a manner that is nondiscriminatory. Shippers on Enable's crude oil gathering pipelines may protest its tariff filings, file complaints against its existing rates, or the FERC can investigate Enable's rates on its own initiative. In the event that the FERC finds that Enable's existing or proposed rates are unjust and unreasonable, it could deny requested rate increases or could order Enable to reduce its rates and could require the payment of reparations to complaining shippers for up to two years prior to the complaint.

On December 22, 2017, the 2017 Tax Act was enacted, which reduced the highest marginal U.S. federal corporate income tax rate from 35 percent to 21 percent for tax years beginning after December 31, 2017. Following the effective date of the law, the FERC orders granting certificates to construct proposed pipeline facilities have directed pipelines proposing new rates for service on those facilities to re-file such rates so that the rates reflect the reduction in the corporate tax rate, the FERC has issued data requests in pending certificate proceedings for proposed pipeline facilities requesting pipelines to explain the impacts of the reduction in the corporate tax rate on the rate proposals in those proceedings and to provide re-calculated initial rates for service on the proposed pipeline facilities, and filings have been made at the FERC requesting that the FERC require pipelines to lower their transportation rates to account for lower corporate taxes. Enable's current tariff rates on file with the FERC incorporate the federal income tax rates that were in effect at the time those tariff rates were established. If the FERC requires Enable to establish new tariff rates that reflect a lower federal corporate income tax rate, it is possible the rates would be reduced, which could adversely affect Enable's financial position, results of operations and ability to make cash distributions to its unitholders, including us.

Enable's operations may also be subject to regulation by state and local regulatory authorities. Changes or additional regulatory measures adopted by such authorities could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us.

The pipeline operations of Enable that are not regulated by the FERC may be subject to state and local regulation applicable to intrastate natural and transportation services. The relevant states in which it operates include North Dakota, Oklahoma, Arkansas, Louisiana, Texas, Missouri, Kansas, Mississippi, Tennessee and Illinois. State and local regulations generally focus on safety, environmental and, in some circumstances, prohibition of undue discrimination among shippers. Additional rules and legislation pertaining to these matters are considered and, in some instances, adopted from time to time. The effect, if any, such changes might have on operations cannot be predicted, but Enable could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes. Other state and local regulations also may affect the business. Any such state or local regulation could have an adverse effect on the business and the financial position, results of operations and ability to make cash distributions to unitholders, including us.

Gathering lines may be subject to ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, oil or natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict the right by Enable as an owner of gathering facilities to decide with whom it contracts to purchase or transport oil or natural gas. Federal law leaves economic regulation of natural gas gathering to the states. The states in which it operates have adopted complaint-based regulation of oil and natural gas gathering activities, which allows oil and natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to access to oil and natural gas gathering pipelines and rate discrimination.

Other state regulations may not directly regulate the business, but may nonetheless affect the availability of natural gas for processing, including state regulation of production rates and maximum daily production allowable from gas wells. While its gathering lines are currently subject to limited state regulation, there is a risk that state laws will be changed, which may give producers a stronger basis to challenge the regulatory status of a line, or the rates, terms and conditions of a gathering line providing transportation service.

A change in the jurisdictional characterization of some of Enable's assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of its assets, which may cause its revenues to decline and operating expenses to increase.

Enable's natural gas gathering and intrastate transportation operations are generally exempt from the jurisdiction of the FERC under the Natural Gas Act, but the FERC regulation may indirectly impact these businesses and the markets for products derived from these businesses. The FERC's policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on interstate open access transportation, ratemaking, capacity release, and market center promotion may indirectly affect intrastate markets. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, it cannot be assured that the FERC will continue to pursue this approach as it considers matters such as pipeline rates and rules and policies that may indirectly affect the intrastate natural gas transportation business. Although the FERC has not made a formal determination with respect to all of its facilities they consider to be gathering facilities, Enable believes that its natural gas gathering pipelines meet the traditional tests that the FERC has used to determine that a pipeline is a gathering pipeline and is therefore not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of its gathering facilities is subject to change based on future determinations by the FERC, the courts or Congress. If the FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the Natural Gas Act and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the Natural Gas Act or the Natural Gas Policy Act. Such regulation could decrease revenue, increase operating costs and, depending upon the facility in question, could adversely affect Enable's financial condition, results of operations and ability to make cash distributions to its unitholders, including us. In addition, if any of Enable's facilities were found to have provided services or otherwise operated in violation of the Natural Gas Act or Natural Gas Policy Act regulations, this could result in the imposition of substantial civil penalties, as well as a requirement to disgorge revenues collected for such services in excess of the maximum rates established by the FERC.

Natural gas gathering may receive greater regulatory scrutiny at the state level; therefore, Enable's natural gas gathering operations could be adversely affected should it become subject to the application of state regulation of rates and services. Enable's gathering operations could also be subject to safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance of gathering facilities. The effect, if any, such changes might have on its operations cannot be predicted, but additional capital expenditures could be required and increased costs could be incurred depending on future legislative and regulatory changes.

Enable may incur significant costs and liabilities resulting from compliance with pipeline safety laws and regulations, pipeline integrity and other similar programs and related repairs.

Certain of Enable's pipeline operations are subject to pipeline safety laws and regulations. The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration regulates safety requirements for the design, construction, maintenance and operation of its jurisdictional natural gas and hazardous liquids pipeline facilities. All of Enable's interstate and intrastate natural gas transportation pipeline facilities are Pipeline and Hazardous Materials Safety Administration jurisdictional and certain of Enable's natural gas gathering, NGL and crude oil pipeline facilities are Pipeline and Hazardous Materials Safety Administration jurisdictional. Among other things, these laws and regulations require pipeline operators to develop integrity management programs, including more frequent inspections and other measures, for pipelines located in "high consequence areas." The regulations require operators, including Enable, to, among other things:

- perform ongoing assessments of pipeline integrity;
- develop a baseline plan to prioritize the assessment of a covered pipeline segment;
- identify and characterize applicable threats that could impact a high consequence area;
- improve data collection, integration, and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating action.

Failure to comply with the Pipeline and Hazardous Materials Safety Administration or comparable state pipeline safety regulations could result in a number of consequences which may have an adverse effect on Enable's operations. Enable incurs significant costs associated with its compliance with existing Pipeline and Hazardous Materials Safety Administration and comparable state pipeline regulations. Enable currently estimates that it will incur maintenance and capital expenditures and operation and maintenance expenses of up to $285.0 million from 2018 through 2022 to comply with existing pipeline safety laws and regulations related to integrity assessments and repairs. Enable may incur significant cost associated with repair, remediation, preventative and mitigation measures associated with its integrity management programs for pipelines that are not currently subject to regulation by the Pipeline and Hazardous Materials Safety Administration.

Changes to pipeline safety laws and regulations that result in more stringent or costly safety standards could have a significant adverse effect on Enable. For example, in August 2011, the Pipeline and Hazardous Materials Safety Administration published an advance notice of proposed rulemaking in which the agency was seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revising the definitions of "high consequence areas" and "gathering lines" and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. On April 8, 2016, the Pipeline and Hazardous Materials Safety Administration published a notice of proposed rulemaking responding to several of the integrity management topics raised in the August 2011 advance notice of proposed rulemaking and proposing new requirements to address safety issues for natural gas transmission and gathering lines that have arisen since the issuance of the advance notice of proposed rulemaking. The proposed rule would strengthen existing integrity management requirements, expand assessment and repair requirements to pipelines in areas with medium population densities, and extend regulatory requirements to onshore gas gathering lines that are currently exempt. Comments were due July 7, 2016. The Pipeline and Hazardous Materials Safety Administration issued, but has yet to publish, a similar rule for hazardous liquids (including oil) pipelines on January 13, 2017. This rule extends regulatory reporting requirements to all liquid gathering lines, require additional event-driven and periodic inspections, require use of leak detection systems on all hazardous liquid pipelines, modify repair criteria, and require certain pipelines to eventually accommodate inline inspection tools. It is unclear when or if this rule will go into effect as, on January 20, 2017, the Trump Administration requested that all regulations that had been sent to the Office of the Federal Register, but not yet published, be immediately withdrawn for further review. Enable is still monitoring and evaluating the effect of these requirements and proposals on its operations.

Proposed rulemakings such as the notice of proposed rulemakings published on October 13, 2015 and April 8, 2016 could expand the scope of the natural gas and hazardous liquids integrity management programs and other related pipeline safety regulations to include additional requirements or previously exempt pipelines. Enable have not estimated the cost of complying with any proposed changes to the regulations administered by the Pipeline and Hazardous Materials Safety Administration or state pipeline safety regulators.

Financial reform regulations under the Dodd-Frank Act could adversely affect Enable's ability to use derivative instruments to hedge risks associated with its business.

At times, Enable may hedge all or a portion of its commodity risk and its interest rate risk. The federal government regulates the derivatives markets and entities, including businesses like Enable, that participate in those market through the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which requires the Commodity Futures Trading Commission and the Securities and Exchange Commission to promulgate rules and regulations implementing the legislation. Under the Commodity Futures Trading Commission's regulations, Enable is subject to reporting and recordkeeping obligations for transactions involving non-financial swap transactions the Commodity Futures Trading Commissions initially adopted regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, but these rules were successfully challenged in federal district court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association and largely vacated by the court. In December 2013, the Commodity Futures Trading Commission published a notice of proposed rulemaking designed to implement new position limits regulation and in December 2016, the Commodity Futures Trading Commission's re-proposed regulations for position limits. The ultimate form and timing of the implementation of the regulatory regime affecting commodity derivatives remains uncertain.

The Commodity Futures Trading Commission has imposed mandatory clearing requirements on certain categories of swaps, including certain interest rate swaps, but has exempted derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement, where the counterparty such as Enable has required identification number, is not a financial entity as defined by the regulations, and meets a minimum asset test. Enable's management believes its hedging transactions qualify for this "commercial end-user" exception. The Dodd-Frank Act may also require Enable to comply with margin requirements in connection with its hedging activities, although the application of those provisions to Enable is uncertain at this time. The Dodd-Frank Act may also require the counterparties to its derivative instruments to spin off some of their hedging activities to a separate entity, which may not be as creditworthy as the current counterparty.

The Dodd-Frank Act and related regulations could significantly increase the cost of derivatives contracts for Enable's industry (including requirements to post collateral which could adversely affect Enable's available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks Enable encounters, reduce its ability to monetize or restructure its existing derivatives contracts, and increase its exposure to less creditworthy counterparties, particularly if Enable is unable to utilize the commercial end user exception with respect to certain of its hedging transactions. If Enable reduces its use of hedging as a result of the legislation and regulations, its results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect its ability to plan for and fund capital expenditures and fund unitholder distributions. Finally, the legislation was intended, in part, to reduce the volatility of crude oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to crude oil and natural gas. Enable's revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could adversely affect its results of operations and its ability to make cash distributions to unitholders, including us.

Any reductions in Enable's credit ratings could increase its financing costs and the cost of maintaining certain contractual relationships.

Enable cannot provide assurance that its credit ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances warrant. If any of Enable's credit ratings are below investment grade, it may have higher future borrowing costs and it or its subsidiaries may be required to post cash collateral or letters of credit under certain contractual agreements. If cash collateral requirements were to occur at a time when Enable was experiencing significant working capital requirements or otherwise lacked liquidity, its financial position, results of operations and ability to make cash distributions to unitholders, including us, could be adversely affected.

Enable's Series A Preferred Units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of its common units.

Enable's 10 percent Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units representing limited partner interests in Enable, issued in February 2016, rank senior to all of its other classes or series of equity securities with respect to distribution rights and rights upon liquidation. Enable cannot declare or pay a distribution to its common unitholders for any quarter unless full distributions have been or contemporaneously are being paid on all outstanding Series A Preferred Units for such quarter. These preferences could adversely affect the cash distributions we receive from Enable, or could make it more difficult for Enable to sell its common units in the future.

Holders of the Series A Preferred Units will receive, on a non-cumulative basis and if and when declared by Enable's general partner, a quarterly cash distribution, subject to certain adjustments, equal to an annual rate of 10 percent on the stated liquidation preference from the date of original issue to, but not including, the five year anniversary of the original issue date, and an annual rate of the London Interbank Offered Rate plus a spread of 850 basis points on the stated liquidation preference thereafter. In connection with certain transfers of the Series A Preferred Units, the Series A Preferred Units will automatically convert into one or more new series of preferred units (the "other preferred units") on the later of the date of transfer or the second anniversary of the date of issue. The other preferred units will have the same terms as Enable's Series A Preferred Units except that unpaid distributions on the other preferred units will accrue from the date of their issuance on a cumulative basis until paid. Enable's Series A Preferred Units are convertible into common units by the holders of such units in certain circumstances. Payment of distributions on Enable's Series A Preferred Units, or on the common units issued following the conversion of such Series A Preferred Units, could impact its liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions, and other general partnership purposes. Enable's obligations to the holders of Series A Preferred Units could also limit its ability to obtain additional financing or increase its borrowing costs, which could have an adverse effect on its financial condition.

Enable's Series A Preferred Units contain covenants that may limit its business flexibility.

Enable's Series A Preferred Units contain covenants preventing it from taking certain actions without the approval of the holders of 66 2/3 percent of the Series A Preferred Units. The need to obtain the approval of holders of the Series A Preferred Units before taking these actions could impede Enable's ability to take certain actions that its management or its board of directors may consider to be in the best interests of its unitholders. The affirmative vote of 66 2/3 percent of the outstanding Series A Preferred Units, voting as a single class, is necessary to amend Enable's Partnership Agreement in any manner that would or could reasonably be expected to have a material adverse effect on the rights, preferences, obligations or privileges of the Series A Preferred Units. The affirmative vote of 66 2/3 percent of the outstanding Series A Preferred Units and any outstanding series of other preferred units, voting as a single class, is necessary to (A) create or issue certain party securities with proceeds in an aggregate

amount in excess of $700.0 million or create or issue any senior securities or (B) subject to Enable's right to redeem the Series A Preferred Units, approve certain fundamental transactions.

Enable's Series A Preferred Units are required to be redeemed in certain circumstances if they are not eligible for trading on the New York Stock Exchange, and Enable may not have sufficient funds to redeem its Series A Preferred Units if it is required to do so.

The holders of Enable's Series A Preferred Units may request that Enable list those units for trading on the New York Stock Exchange. If Enable is unable to list the Series A Preferred Units in certain circumstances, it will be required to redeem the Series A Preferred Units. There can be no assurance that Enable would have sufficient financial resources available to satisfy its obligation to redeem the Series A Preferred Units. In addition, mandatory redemption of Enable's Series A Preferred Units could adversely affect its financial position, results of operations and ability to make quarterly cash distributions to its unitholders, including us.

Enable may issue additional units without the approval of its unitholders, which would dilute unitholders' existing ownership interests.

Enable's partnership agreement does not limit the number of additional limited partner interests, including limited partner interests that rank senior to the common units, that it may issue at any time without the approval of its unitholders. The issuance by Enable of additional common units or other equity securities of equal or senior rank will have the following effects:

- Enable's existing unitholders' proportionate ownership interest in Enable will decrease;
- the amount of distributable cash flow on each unit may decrease;
- because the amount payable to holders of incentive distribution rights is based on a percentage of the total distributable cash flow, the distributions to holders of incentive distribution rights will increase even if the per unit distribution on common units remains the same;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

In addition, upon a change of control or certain fundamental transactions, Enable's Series A Preferred Units are convertible into common units at the option of the holders of such units. If a substantial portion of the Series A Preferred Units were converted into common units, common unitholders could experience significant dilution. In addition, if holders of such converted Series A Preferred Units were to dispose of a substantial portion of these common units in the public market, whether in a single transaction or series of transactions, it could adversely affect the market price for Enable's common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for Enable to sell its common units in the future.

Affiliates of Enable's general partner may sell common units in the public or private markets, which could have an adverse impact on the trading price of the common units and may sell their interest in its general partner, which may impact its strategic direction.

As of February 1, 2018, CenterPoint held 233,856,623 of Enable's common units and 14,520,000 Series A Preferred Units, and the Company held 110,982,805 of Enable's common units. Enable's Series A Preferred Units are convertible into common units upon a change of control or certain fundamental transactions at the option of the holders of such units. Both Enable's common units held by CenterPoint and the Company, as well as Enable's Series A Preferred Units held by CenterPoint, are subject to certain registration rights. In addition, CenterPoint has publicly disclosed that it is evaluating strategic alternatives for its investment in Enable. CenterPoint has disclosed that the alternatives may include a sale of all or a portion of the interests that it owns in Enable and the general partner of Enable, that if the sale option is not viable it intends to reduce its ownership in Enable over time through a sale of the common units it holds in the public equity markets subject to market conditions, and that there can be no assurances that these evaluations will result in any specific action. CenterPoint's disclosure, as well as any sales by CenterPoint of the common units it holds in the public or equity markets, could have an adverse impact on the market for Enable's common units, including its ability to issue equity on favorable terms to fund its capital needs or at all. Any sale of Enable's general partner by CenterPoint or the Company may impact Enable's strategic direction, business or results of operations.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

OG&E

OG&E owns and operates an interconnected electric generation, transmission and distribution system, located in Oklahoma and western Arkansas, which included 10 generating stations with an aggregate capability of 6,304 MWs at December 31, 2017. The following tables set forth information with respect to OG&E's electric generating facilities, all of which are located in Oklahoma.

Station & Unit		Year Installed	Unit Design Type	Fuel Capability	2017 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Seminole	1	1971	Steam-Turbine	Gas	6.0%	434	
	2	1973	Steam-Turbine	Gas	8.0%	430	
	3	1975	Steam-Turbine	Gas/Oil	8.5%	456	1,320
Muskogee	4	1977	Steam-Turbine	Coal	49.2%	493	
	5	1978	Steam-Turbine	Coal	36.8%	498	
	6	1984	Steam-Turbine	Coal	55.5%	518	1,509
Sooner	1	1979	Steam-Turbine	Coal	39.0%	520	
	2	1980	Steam-Turbine	Coal	38.2%	519	1,039
Horseshoe Lake	6	1958	Steam-Turbine	Gas/Oil	4.1%	167	
	7	1963	Combined Cycle	Gas/Oil	4.5%	214	
	8	1969	Steam-Turbine	Gas	3.5%	397	
	9	2000	Combustion-Turbine	Gas	9.7%	45	
	10	2000	Combustion-Turbine	Gas	9.6%	43	866
Redbud (B)	1	2003	Combined Cycle	Gas	51.0%	153	
	2	2003	Combined Cycle	Gas	45.1%	153	
	3	2003	Combined Cycle	Gas	48.5%	154	
	4	2003	Combined Cycle	Gas	42.9%	153	613
Mustang (C)	5A	1971	Combustion-Turbine	Gas/Jet Fuel	0.5%	33	
	5B	1971	Combustion-Turbine	Gas/Jet Fuel	0.5%	32	
	8	2017	Combustion-Turbine	Gas	—%	60	125
McClain (D)	1	2001	Combined Cycle	Gas	80.5%	380	380
Total Generating Capability (all stations, excluding renewable)							5,852

Renewable

Station	Year Installed	Location	Number of Units	Fuel Capability	2017 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Crossroads	2011	Canton, OK	98	Wind	40.9%	2.3	228
Centennial	2007	Laverne, OK	80	Wind	23.3%	1.5	120
OU Spirit	2009	Woodward, OK	44	Wind	34.8%	2.3	101
Mustang	2015	Oklahoma City, OK	90	Solar	22.5%	—	3
Total Generating Capability (renewable)							452

(A) 2017 Capacity Factor = 2017 Net Actual Generation / (2017 Net Maximum Capacity (Nameplate Rating in MWs) x Period Hours (8,760 Hours))
(B) Represents OG&E's 51 percent ownership interest in the Redbud Plant.
(C) On December 31, 2017, Mustang units 3 and 4 were retired. On December 30, 2017, Mustang unit 8, the first of seven efficient combustion turbines installed as part of the Mustang Modernization Plan, was placed in service. The Company expects units 6, 7, 9, 10, 11 and 12 to be placed in service at various times during the first quarter of 2018.
(D) Represents OG&E's 77 percent ownership interest in the McClain Plant.

At December 31, 2017, OG&E's transmission system included: (i) 52 substations with a total capacity of 13.3 million kV-amps and 4,949 structure miles of lines in Oklahoma and (ii) seven substations with a total capacity of 2.9 million kV-amps and 277 structure miles of lines in Arkansas. OG&E's distribution system included: (i) 346 substations with a total capacity of 9.7 million kV-amps, 29,317 structure miles of overhead lines, 2,824 miles of underground conduit and 10,875 miles of underground

conductors in Oklahoma and (ii) 30 substations with a total capacity of 0.9 million kV-amps, 2,785 structure miles of overhead lines, 282 miles of underground conduit and 689 miles of underground conductors in Arkansas.

OG&E owns 140,133 square feet of office space at its executive offices at 321 North Harvey, Oklahoma City, Oklahoma 73102. In addition to its executive offices, OG&E owns numerous facilities throughout its service territory that support its operations. These facilities include, but are not limited to, service centers, fleet and equipment service facilities, operation support and other properties.

During the three years ended December 31, 2017, the Company's gross property, plant and equipment (excluding construction work in progress) additions were $1.4 billion, and gross retirements were $315.5 million. These additions were provided by cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper), long-term borrowings and permanent financings. The additions during this three-year period amounted to 12.5 percent of gross property, plant and equipment (excluding construction work in progress) at December 31, 2017.

Item 3. Legal Proceedings.

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by GAAP, an estimate is made of the loss, and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. At the present time, based on currently available information, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures.

Not Applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

The Company's common stock is listed for trading on the New York Stock Exchange under the ticker symbol "OGE." The following table gives information with respect to price ranges, as reported in *The Wall Street Journal* as New York Stock Exchange Composite Transactions, and dividends paid for the periods shown.

		Price	
2017	Dividend Paid	High	Low
First Quarter	$ 0.3025	$ 37.41	$ 32.85
Second Quarter	0.3025	37.25	33.45
Third Quarter	0.3025	36.67	33.95
Fourth Quarter	0.3325	37.32	32.60
2016			
First Quarter	$ 0.2750	$ 28.74	$ 23.37
Second Quarter	0.2750	32.75	27.27
Third Quarter	0.2750	33.10	29.91
Fourth Quarter	0.3025	34.23	29.57

At the Company's September 2017 board meeting, the Board of Directors approved management's recommendation of a 10 percent increase in the quarterly dividend rate to $0.3325 per share from $0.3025 per share effective in October 2017.

The number of record holders of the Company's common stock at December 31, 2017, was 14,920. The book value of the Company's common stock at December 31, 2017 was $32.91 per share.

Dividend Restrictions

Before the Company can pay any dividends on its common stock, the holders of any of its preferred stock that may be outstanding are entitled to receive their dividends at the respective rates as may be provided for the shares of their series. Currently, there are no shares of preferred stock of the Company outstanding. Because the Company is a holding company and conducts all of its operations through its subsidiaries and equity affiliates, the Company's cash flow and ability to pay dividends is dependent on the earnings and cash flows of its subsidiaries and equity affiliate and the distribution or other payments of those earnings to the Company in the form of dividends or distributions or in the form of repayments of loans or receipt of advances. The Company expects to derive principally all of the funds required by it to enable it to pay dividends on its common stock from dividends paid by OG&E, on OG&E's common stock. The Company may also utilize distributions paid by Enable to help fund its capital needs and support future dividend growth. The Company's ability to receive dividends on OG&E's common stock is subject to the prior rights of the holders of any OG&E preferred stock that may be outstanding, any covenants of OG&E's certificate of incorporation and OG&E's debt instruments limiting the ability of OG&E to pay dividends and the ability of public utility commissions that regulate OG&E to effectively restrict the payment of dividends by OG&E. The Company's ability to receive distributions on its limited partnership interest in Enable is subject to Enable's cash available for distribution, the terms of its limited partnership agreement and the covenants of Enable's debt instruments limiting the ability of Enable to pay distributions. Enable's partnership agreement requires that it distribute all "available cash," as defined as cash on hand at the end of a quarter after the payment of expenses and the establishment of cash reserves and cash on hand resulting from working capital borrowings made after the end of the quarter.

Pursuant to the leverage restriction in the Company’s revolving credit agreement, the Company must maintain a percentage of debt to total capitalization at a level that does not exceed 65 percent. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization, which results in the restriction of approximately $605.3 million of the Company’s retained earnings from being paid out in dividends. Accordingly, approximately $2.2 billion of the Company’s retained earnings as of December 31, 2017 are unrestricted for the payment of dividends.

Pursuant to the Federal Power Act, OG&E is restricted from paying dividends from its capital accounts. Dividends are paid from retained earnings. Pursuant to the leverage restriction in OG&E’s revolving credit agreement, OG&E must also maintain a percentage of debt to total capitalization at a level that does not exceed 65 percent. The payment of cash dividends indirectly

results in an increase in the percentage of debt to total capitalization, which results in the restriction of approximately $600.1 million of OG&E's retained earnings from being paid out in dividends. Accordingly, approximately $1.8 billion of OG&E's retained earnings as of December 31, 2017 are unrestricted for the payment of dividends.

Issuer Purchases of Equity Securities

None.

Item 6. Selected Financial Data.

HISTORICAL DATA

Year Ended December 31	**2017**	2016	2015	2014	2013
SELECTED FINANCIAL DATA					
(In millions, except per share data)					
Results of Operations Data (A)					
Operating revenues	**$ 2,261.1**	$ 2,259.2	$ 2,196.9	$ 2,453.1	$ 2,867.7
Cost of sales	**897.6**	880.1	865.0	1,106.6	1,428.9
Operating expenses	**853.2**	875.8	850.7	809.7	885.3
Operating income	**510.3**	503.3	481.2	536.8	553.5
Equity in earnings of unconsolidated affiliates	**131.2**	101.8	15.5	172.6	101.9
Allowance for equity funds used during construction	**39.7**	14.2	8.3	4.2	6.6
Other income	**46.4**	26.0	27.0	17.8	31.8
Other expense	**14.1**	16.9	14.3	14.4	22.2
Interest expense	**143.8**	142.1	149.0	148.4	147.5
Income tax (benefit) expense	**(49.3)**	148.1	97.4	172.8	130.3
Net income	**619.0**	338.2	271.3	395.8	393.8
Less: Net income attributable to noncontrolling interests	**—**	—	—	—	6.2
Net income attributable to OGE Energy	**$ 619.0**	$ 338.2	$ 271.3	$ 395.8	$ 387.6
Basic earnings per average common share attributable to OGE Energy common shareholders	**$ 3.10**	$ 1.69	$ 1.36	$ 1.99	$ 1.96
Diluted earnings per average common share attributable to OGE Energy common shareholders	**$ 3.10**	$ 1.69	$ 1.36	$ 1.98	$ 1.94
Dividends declared per common share	**$ 1.27000**	$ 1.15500	$ 1.05000	$ 0.95000	$ 0.85125
Balance Sheet Data (at period end)					
Property, plant and equipment, net	**$ 8,339.9**	$ 7,696.2	$ 7,322.4	$ 6,979.9	$ 6,672.8
Total assets	**$ 10,412.7**	$ 9,939.6	$ 9,580.6	$ 9,509.9	$ 9,120.5
Long-term debt	**$ 2,999.4**	$ 2,630.5	$ 2,738.8	$ 2,737.4	$ 2,385.9
Total stockholders' equity	**$ 3,851.1**	$ 3,443.8	$ 3,326.0	$ 3,244.4	$ 3,037.1
Capitalization Ratios (B)					
Stockholders' equity	**56.2%**	56.7%	54.7%	54.1%	55.9%
Long-term debt	**43.8%**	43.3%	45.3%	45.9%	44.1%
Ratio of Earnings to Fixed Charges (C)					
Ratio of earnings to fixed charges	**4.42**	4.41	4.12	4.49	3.98

(A) In May 2013, Enable was formed to own and operate the midstream businesses of OGE Energy and CenterPoint. OGE Energy accounts for its interest in Enable using the equity method of accounting subsequent to the formation of Enable. Prior to May 1, 2013, OGE Energy consolidated the results of Enogex LLC.

(B) Capitalization ratios = [Total stockholders' equity / (Total stockholders' equity + Long-term debt + Long-term debt due within one year)] and [(Long-term debt + Long-term debt due within one year) / (Total stockholders' equity + Long-term debt + Long-term debt due within one year)].

(C) For purposes of computing the ratio of earnings to fixed charges, (i) earnings consist of income from continuing operations before income taxes and equity in earnings of unconsolidated affiliates, plus distributed equity income plus fixed charges, less allowance for borrowed funds used during construction and other capitalized interest and (ii) fixed charges consist of interest on long-term debt, related amortization, interest on short-term borrowings and a calculated portion of rents considered to be interest.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Introduction

The Company is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central U.S. The Company conducts these activities through two business segments: (i) electric utility and (ii) natural gas midstream operations. The accounts of the Company and its wholly owned subsidiaries are included in the consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation. The Company generally uses the equity method of accounting for investments where its ownership interest is between 20 percent and 50 percent and it lacks the power to direct activities that most significantly impact economic performance.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E and are subject to regulation by the OCC, the APSC and the FERC. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory and is a wholly owned subsidiary of the Company. OG&E is the largest electric utility in Oklahoma, and its franchised service territory includes Fort Smith, Arkansas and the surrounding communities. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

The natural gas midstream operations segment represents the Company's investment in Enable through wholly owned subsidiaries and ultimately OGE Holdings. Enable is engaged in the business of gathering, processing, transporting and storing natural gas. Enable's natural gas gathering and processing assets are strategically located in four states and serve natural gas production from shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. Enable also owns an emerging crude oil gathering business in the Bakken Shale formation, principally located in the Williston Basin of North Dakota. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

Enable was formed effective May 1, 2013 by the Company, the ArcLight group and CenterPoint to own and operate the midstream businesses of the Company and CenterPoint. In the formation transaction, the Company and the ArcLight group contributed Enogex LLC to Enable, and the Company deconsolidated its previously held investment in Enogex Holdings and acquired an equity interest in Enable. The Company determined that its contribution of Enogex LLC to Enable met the requirements of being in substance real estate and was recorded at historical cost. The general partner of Enable is equally controlled by the Company and CenterPoint, who each have 50 percent management ownership. Based on the 50/50 management ownership, with neither company having control, the Company began accounting for its interest in Enable using the equity method of accounting.

In April 2014, Enable completed an initial public offering of 25.0 million common units resulting in Enable becoming a publicly traded Master Limited Partnership. At December 31, 2017, the Company owned 111.0 million common units, or 25.7 percent, of Enable's outstanding common units. For additional information on the Company's equity investment in Enable and related party transactions, see Note 3 in "Item 8. Financial Statements and Supplementary Data."

Over the course of 2015 and continuing into early 2016, natural gas and crude oil prices dropped to their lowest levels in over 10 years. During 2016 and 2017, those prices increased, and have stabilized, but have not rebounded to the pre-2015 levels. Based on these recent commodity prices, Enable has seen changes in producer activity that have negatively impacted Enable's operations and financial position and could see additional changes in producer activity that may negatively impact Enable's operations and affect its future distribution rates. If commodity prices decline further, Enable's future operating results and cash flows could be negatively impacted. A portion of our earnings and operating cash flows depend on the performance of, and distributions from, Enable. As disclosed in this Form 10-K, Enable is subject to a number of risks, including contract renewal risk, the reliance on the drilling and production decisions of others and the volatility of natural gas, NGL and crude oil prices. If any of those risks were to occur, the Company's business, financial condition, results of operations or cash flows could be materially adversely affected.

On February 9, 2018, Enable announced a quarterly dividend distribution of $0.31800 per unit on its outstanding common units, which is unchanged from the previous quarter. If cash distributions to Enable’s unitholders exceed $0.330625 per unit in any quarter, the general partner will receive increasing percentages, up to 50 percent, of the cash Enable distributes in excess of that amount. The Company is entitled to 60 percent of those "incentive distributions."

OG&E participates in the SPP Integrated Marketplace. As part of the Integrated Marketplace, the SPP has balancing authority responsibilities for its market participants. The SPP Integrated Marketplace functions as a centralized dispatch, where market participants, including OG&E, submit offers to sell power to the SPP from their resources and bid to purchase power from the SPP for their customers. The SPP Integrated Marketplace is intended to allow the SPP to optimize supply offers and demand bids based upon reliability and economic considerations and to determine which generating units will run at any given time for

maximum cost-effectiveness. As a result, OG&E's generating units produce output that is different from OG&E's customer load requirements. Net fuel and purchased power costs are recovered through fuel adjustment clauses.

Overview

Company Strategy

The Company's mission, through OG&E and its equity interest in Enable, is to fulfill its critical role in the nation's electric utility and natural gas midstream pipeline infrastructure and meet individual customer's needs for energy and related services, focusing on safety, efficiency, reliability, customer service and risk management. The Company's corporate strategy is to continue to maintain its existing business mix and diversified asset position of its regulated electric utility business and interest in a publicly traded midstream company, while providing competitive energy products and services to customers, as well as seeking growth opportunities in both businesses.

OG&E is focused on:

- providing exceptional customer experiences by continuing to improve customer interfaces, tools, products and services that deliver high customer satisfaction and operating productivity;
- providing safe, reliable energy to the communities and customers we serve, with a particular focus on enhancing the value of the grid by improving distribution grid reliability by reducing the frequency and duration of customer interruptions and leveraging previous grid technology investments;
- having strong regulatory and legislative relationships for the long-term benefit of our customers, investors and members;
- continuing to grow a zero-injury culture and deliver top-quartile safety results;
- complying with the EPA's Regional Haze Rule requirements;
- ensuring we have the necessary mix of generation resources to meet the long-term needs of our customers; and
- continuing focus on operational excellence and efficiencies in order to protect the customer bill.

Additionally, the Company wants to achieve a premium valuation of its businesses relative to its peers, grow earnings per share with a stable earnings pattern, create a high performance culture and achieve desired outcomes with target stakeholders. The Company's financial objectives include a long-term annual earnings growth rate for OG&E of three to five percent on a weather-normalized basis, maintaining a strong credit rating as well as targeting dividend increases of approximately 10 percent annually through 2019. The targeted annual dividend increase has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets and the composition of the Company's assets and investment opportunities. The Company also utilizes cash distributions from its investment in Enable to help fund its capital needs and support future dividend growth. The Company believes it can accomplish these financial objectives by, among other things, pursuing multiple avenues to build its business, maintaining a diversified asset position, continuing to develop a wide range of skills to succeed with changes in its industries, providing products and services to customers efficiently, managing risks effectively and having strong regulatory and legislative relationships.

Summary of Operating Results

2017 compared to 2016. Net income was $619.0 million, or $3.10 per diluted share, in 2017 as compared to $338.2 million, or $1.69 per diluted share, in 2016. The increase in net income of $280.8 million, or 83.0 percent, or $1.41 per diluted share, in 2017 as compared to 2016 was primarily due to:

- an increase in net income at OGE Holdings of $271.5 million, or $1.36 per diluted share of the Company's common stock, primarily due to an income tax benefit of $245.2 million as a result of the 2017 Tax Act and an increase of equity in earnings of Enable; and
- an increase in net income at OG&E of $21.4 million, or $0.11 per diluted share of the Company's common stock, primarily due to higher net other income and lower depreciation and amortization expense as a result of the March 2017 OCC rate order mandating a reduction in depreciation rates, partially offset by higher income tax expense, higher operation and maintenance expense and lower gross margin primarily due to milder weather; partially offset by
- an increase in net loss of other operations of $12.1 million, or $0.06 per diluted share of the Company's common stock, primarily due to income tax expense of $10.5 million as a result of the 2017 Tax Act.

2016 compared to 2015. Net income was $338.2 million, or $1.69 per diluted share, in 2016 as compared to $271.3 million, or $1.36 per diluted share, in 2015. The increase in net income of $66.9 million, or 24.7 percent, or $0.33 per diluted share, in 2016 as compared to 2015 was primarily due to:

- an increase in net income at OGE Holdings of $44.3 million, or $0.22 per diluted share of the Company's common stock, primarily due to the goodwill impairment adjustment at Enable in September 2015, partially offset by higher income tax expense due to higher pre-tax operating income and a change in state tax rates;
- an increase in net income at OG&E of $15.2 million, or $0.07 per diluted share of the Company's common stock, primarily due to an increase in gross margin related to warmer summer weather and increased wholesale transmission revenues and an increase in other income. Partially offsetting these items was an increase in other operation and maintenance expense, an increase in depreciation expense due to additional assets being placed in service and an increase in income tax expense; and
- an increase in net income of other operations of $7.4 million, or $0.04 per diluted share of the Company's common stock, primarily due to charges in 2015 associated with pre-construction expenditures for cancelled new office space to consolidate Oklahoma City personnel and a decrease in depreciation, partially offset by an increase in interest expense.

A more detailed discussion regarding the financial performance of OG&E and the Natural Gas Midstream Operations can be found under "Results of Operations" below.

2018 Outlook

Key assumptions for 2018 include:

OG&E

The Company projects OG&E to earn approximately $286 million to $306 million or $1.43 to $1.53 per average diluted share in 2018 and is based on the following assumptions:

- normal weather patterns are experienced for the remainder of the year;
- gross margin on revenues of approximately $1.380 billion to $1.390 billion based on sales growth of approximately one percent on a weather-adjusted basis;
- operating expenses of approximately $927 million to $937 million, with operation and maintenance expenses comprising approximately 53 percent of the total;
- interest expense of approximately $152 million to $155 million which assumes an $11 million allowance for borrowed funds used during construction reduction to interest expense and assumes a debt refinancing of $250 million in the second half of 2018;
- other income of approximately $33 million including approximately $21 million of allowance for equity funds used during construction;
- assumes a regulatory asset for the Dry Scrubbers for approximately $9 million, or $0.03 per share;
- an effective tax rate of approximately 10.9 percent;
- new rates take effect in Oklahoma by August 1, 2018; and
- every 25 basis point change in the allowed Oklahoma return on equity equates to a change of approximately $8 million in revenue.

OG&E has significant seasonality in its earnings. OG&E typically shows minimal earnings in the first and fourth quarters with a majority of earnings in the third quarter due to the seasonal nature of air conditioning demand.

OGE Holdings

The Company projects the earnings contribution from its ownership interest in Enable for 2018 to be approximately $96 million to $104 million or $0.48 to $0.52 per average diluted share and receive approximately $140 million in cash distributions.

Consolidated OGE

The Company's 2018 earnings guidance is between approximately $380 million and $410 million of net income, or $1.90 to $2.05 per average diluted share and is based on the following assumptions:

- approximately 200 million average diluted shares outstanding;
- an effective tax rate of approximately 14 percent; and
- a $0.00 to $0.01 or up to $2 million loss at OGE Energy (holding company) due to interest expense.

OG&E's Non-GAAP Financial Measures

Gross margin is defined by OG&E as operating revenues less fuel, purchased power and certain transmission expenses. Gross margin is a non-GAAP financial measure because it excludes depreciation and amortization, and other operation and maintenance expenses. Expenses for fuel and purchased power are recovered through fuel adjustment clauses and as a result changes in these expenses are offset in operating revenues with no impact on net income. OG&E believes gross margin provides a more meaningful basis for evaluating its operations across periods than operating revenues because gross margin excludes the revenue effect of fluctuations in these expenses. Gross margin is used internally to measure performance against budget and in reports for management and the Board of Directors. OG&E's definition of gross margin may be different from similar terms used by other companies. For a reconciliation of gross margin to revenue for the years ended December 31, 2017, 2016 and 2015, see OG&E (Electric Utility) Results of Operations below.

Detailed below is a reconciliation of gross margin to revenue included in the 2018 Outlook.

Reconciliation of Gross Margin to Revenue

(In millions)		Twelve Months Ended December 31, 2018 (A)
Operating revenues	$	1,932
Cost of sales		547
Gross margin	$	1,385

(A) Based on the midpoint of OG&E earnings guidance for 2018.

Enable's Non-GAAP Financial Measures

Gross margin is defined by Enable as total revenues minus costs of natural gas and NGLs, excluding depreciation and amortization. Total revenues consist of the fees that they charge their customers and the sales price of natural gas and NGLs that they sell. The cost of natural gas and NGLs consists of the purchase price of natural gas and NGLs that they purchase. Enable deducts the cost of natural gas and NGLs from total revenue to arrive at a measure of the core profitability of their mix of fee-based and commodity-based customer arrangements. Gross margin allows for meaningful comparison of the operating results between Enable's fee-based revenues and Enable's commodity-based contracts which involve the purchase or sale of natural gas, NGLs and/or crude oil. In addition, the Company believes gross margin allows for a meaningful comparison of the results of Enable's commodity-based activities across different commodity price environments because it measures the spread between the product sales price and cost of products sold.

Results of Operations

The following discussion and analysis presents factors that affected the Company's consolidated results of operations for the years ended December 31, 2017, 2016 and 2015 and the Company's consolidated financial position at December 31, 2017 and 2016. The following information should be read in conjunction with the Consolidated Financial Statements and Notes thereto. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

	Year Ended December 31,		
(In millions except per share data)	**2017**	2016	2015
Net income	**$ 619.0**	$ 338.2	$ 271.3
Basic average common shares outstanding	**199.7**	199.7	199.6
Diluted average common shares outstanding	**200.0**	199.9	199.6
Basic earnings per average common share	**$ 3.10**	$ 1.69	$ 1.36
Diluted earnings per average common share	**$ 3.10**	$ 1.69	$ 1.36
Dividends declared per common share	**$ 1.27000**	$ 1.15500	$ 1.05000

Results by Business Segment

	Year Ended December 31,		
(In millions)	**2017**	2016	2015
Net income (loss):			
OG&E (Electric Utility)	**$ 305.5**	$ 284.1	$ 268.9
OGE Holdings (Natural Gas Midstream Operations) (A)	**325.2**	53.7	9.4
Other operations (B)	**(11.7)**	0.4	(7.0)
Consolidated net income	**$ 619.0**	$ 338.2	$ 271.3

(A) The Company recorded an income tax benefit of $245.2 million during the fourth quarter of 2017 due to the Company remeasuring deferred taxes at OGE Holdings, as a result of the 2017 Tax Act. See Note 7 in "Item 8. Financial Statements and Supplementary Data" for further discussion of the effects of the 2017 Tax Act. The Company recorded a $108.4 million pre-tax charge during the third quarter of 2015 for its share of Enable's goodwill impairment, as adjusted for the basis differences. See Note 3 in "Item 8. Financial Statements and Supplementary Data" for further discussion of the goodwill impairment.

(B) The Company recorded an income tax expense of $10.5 million during the fourth quarter of 2017 due to the Company remeasuring deferred taxes at OGE Energy (holding company), as a result of the 2017 Tax Act. Other operations primarily includes the operations of the holding company and consolidating eliminations.

The following operating results analysis by business segment includes intercompany transactions that are eliminated in the Consolidated Financial Statements.

OG&E (Electric Utility)

Year Ended December 31 *(Dollars in millions)*	2017	2016	2015
Operating revenues	**$ 2,261.1**	$ 2,259.2	$ 2,196.9
Cost of sales	**897.6**	880.1	865.0
Other operation and maintenance	**486.1**	469.8	444.5
Depreciation and amortization	**280.9**	316.4	299.9
Taxes other than income	**84.8**	84.0	87.1
Operating income	**511.7**	508.9	500.4
Allowance for equity funds used during construction	**39.7**	14.2	8.3
Other income	**36.6**	16.4	13.3
Other expense	**2.3**	2.9	1.6
Interest expense	**138.4**	138.1	146.7
Income tax expense	**141.8**	114.4	104.8
Net income	**$ 305.5**	$ 284.1	$ 268.9
Operating revenues by classification:			
Residential	**$ 884.1**	$ 951.9	$ 896.5
Commercial	**588.3**	573.7	535.0
Industrial	**200.6**	194.6	190.6
Oilfield	**159.5**	156.9	162.8
Public authorities and street light	**208.0**	204.3	194.2
Sales for resale	**0.2**	0.3	21.7
System sales revenues	**2,040.7**	2,081.7	2,000.8
Provision for rate refund	**26.8**	(33.6)	—
Integrated market	**23.5**	49.3	48.6
Other	**170.1**	161.8	147.5
Total operating revenues	**$ 2,261.1**	$ 2,259.2	$ 2,196.9
Reconciliation of gross margin to revenue			
Operating revenues	**$ 2,261.1**	$ 2,259.2	$ 2,196.9
Cost of sales	**897.6**	880.1	865.0
Gross margin	**$ 1,363.5**	$ 1,379.1	$ 1,331.9
MWh sales by classification *(In millions)*			
Residential	**8.8**	9.3	9.2
Commercial	**7.6**	7.6	7.4
Industrial	**3.6**	3.6	3.6
Oilfield	**3.2**	3.2	3.4
Public authorities and street light	**3.1**	3.2	3.1
Sales for resale	**—**	—	0.5
System sales	**26.3**	26.9	27.2
Integrated market	**1.8**	3.0	1.7
Total sales	**28.1**	29.9	28.9
Number of customers	**841,830**	833,582	824,776
Weighted-average cost of energy per kilowatt-hour *(In cents)*			
Natural gas	**2.821**	2.488	2.529
Coal	**2.069**	2.213	2.187
Total fuel	**2.211**	2.199	2.196
Total fuel and purchased power	**3.049**	2.842	2.874
Degree days (A)			
Heating - Actual	**2,877**	2,800	3,038
Heating - Normal	**3,349**	3,349	3,349
Cooling - Actual	**1,944**	2,247	2,071
Cooling - Normal	**2,092**	2,092	2,092

(A) Degree days are calculated as follows: The high and low degrees of a particular day are added together and then averaged. If the calculated average is above 65 degrees, then the difference between the calculated average and 65 is expressed as cooling degree days, with each degree of difference equaling one cooling degree day. If the calculated average is below 65 degrees, then the difference between the calculated average and 65 is expressed as heating degree days, with each degree of difference equaling one heating degree day. The daily calculations are then totaled for the particular reporting period.

2017 compared to 2016. OG&E's net income increased $21.4 million, or 7.5 percent, in 2017 as compared to 2016, primarily due to lower depreciation and amortization expense as a result of the March 2017 OCC rate order mandating a reduction in depreciation rates, higher allowance for equity funds used during construction, higher other income and higher allowance for borrowed funds used during construction, partially offset by higher income tax expense, higher operation and maintenance expense, lower gross margin and higher interest on long-term debt.

Gross margin was $1,363.5 million in 2017 as compared to $1,379.1 million in 2016, a decrease of $15.6 million, or 1.1 percent. The below factors contributed to the change in gross margin:

(In millions)		**Change**
Weather (price and quantity) (A)	$	(15.1)
Price variance (B)		(13.9)
Wholesale transmission revenue		(8.1)
New customer growth		14.2
Non-residential demand and related revenues		5.0
Industrial and oilfield sales		2.2
Other		0.1
Change in gross margin	$	(15.6)

(A) Cooling degree days decreased approximately 13 percent in 2017.
(B) Decreased primarily due to additional reserves for rate refunds in both Oklahoma and Arkansas, as well as riders moving to base rates in the March 2017 OCC rate order.

Cost of sales for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. The actual cost of fuel used in electric generation and certain purchased power costs are passed through to OG&E's customers through fuel adjustment clauses. The fuel adjustment clauses are subject to periodic review by the OCC and the APSC. OG&E's cost of sales increased $17.5 million, or 2.0 percent, in 2017 as compared to 2016. The changes are detailed in the table below.

(In millions)		**Change**
Fuel expense (A)	$	(61.5)
Purchased power costs:		
Purchases from SPP (B)		74.4
Wind		0.2
Cogeneration		(9.5)
Transmission expense (C)		13.9
Change in cost of sales	$	17.5

(A) Decrease in fuel expense was primarily due to decreased utilization of company-owned generation.
(B) Increase in the cost of purchases from the SPP was due to an increase of 26.8 percent in MWh purchased and an increase of 16.2 percent in cost per MWhs purchased. The increase in cost per MWh purchased was due to an increase in fuel prices and higher grid congestion costs during 2017.
(C) Increase in transmission-related charges was primarily due to higher SPP charges for the base plan projects of other utilities.

Other operation and maintenance expense increased $16.3 million, or 3.5 percent, in 2017 as compared to 2016. The below factors contributed to the change in other operation and maintenance expense:

(In millions)		**Change**
Vegetation management	$	14.5
Other		9.2
Capitalized labor (A)		(7.4)
Change in other operation and maintenance expense	$	16.3

(A) Increased during 2017 primarily due to more storm costs exceeding the $2.7 million OCC-allowed threshold, which were moved to a regulatory asset, as well as mutual assistance, which was provided in the aftermath of Hurricanes Harvey and Irma.

Depreciation and amortization expense decreased $35.5 million, or 11.2 percent, primarily due to lower depreciation expense related to the reduction in depreciation rates approved in the March 2017 OCC rate order as discussed in Note 14 in "Item 8. Financial Statements and Supplementary Data," partially offset by additional assets being placed into service.

Allowance for equity funds used during construction increased $25.5 million, primarily due to higher construction work in progress balances resulting from increased spending for environmental projects.

Other income increased $20.2 million, primarily due to an increase in the tax gross-up related to higher allowance for funds used during construction and an increase in gains on guaranteed flat bill margins.

Allowance for borrowed funds used during construction increased $10.5 million, primarily due to higher construction work in progress balances resulting from increased spending for environmental projects.

Income tax expense increased $27.4 million, or 24.0 percent, primarily due to higher pre-tax operating income and lower tax credits generated.

2016 compared to 2015. OG&E's net income increased $15.2 million, or 5.7 percent, in 2016 as compared to 2015, primarily due to an increase in gross margin related to warmer summer weather and increased transmission revenues and an increase in other income, partially offset by increases in other operation and maintenance expense, depreciation expense and income tax expense.

Gross margin was $1,379.1 million in 2016 as compared to $1,331.9 million in 2015, an increase of $47.2 million, or 3.5 percent. The below factors contributed to the change in gross margin:

(In millions)		**Change**
Interim rate increase - Oklahoma (A)	$	39.0
Reserve for rate refund (A)		(33.7)
Wholesale transmission revenue (B)		20.3
Price variance (C)		18.1
Quantity variance (primarily weather)		13.1
New customer growth		3.2
Non-residential demand and related revenues		0.6
Expiration of AVEC contract (D)		(9.7)
Other		(3.7)
Change in gross margin	$	47.2

(A) As discussed in Note 14 in "Item 8. Financial Statements and Supplementary Data," on July 1, 2016, OG&E implemented an annual interim rate increase of $69.5 million. Interim rates are subject to refund of any amount recovered in excess of the rates ultimately approved by the OCC in the general rate case.

(B) Increased primarily due to the SPP's settlement of revenue credits related to the Windspeed Transmission line for the years 2008 through August 2016. Other increases include a recovery of the base plan projects in the SPP formula rate for 2015 and 2016.

(C) Increased primarily due to the reversal of a reserve for gas transportation charges in addition to the pricing impact of weather related sales.

(D) On June 30, 2015, the wholesale power contract with AVEC expired.

OG&E's cost of sales increased $15.1 million, or 1.7 percent, in 2016 as compared to 2015. The changes are detailed in the table below.

(In millions)		Change
Fuel expense (A)	$	12.2
Purchased power costs:		
Purchases from SPP (B)		(12.3)
Wind		—
Cogeneration		—
Transmission expense (C)		15.2
Change in cost of sales	$	15.1

(A) Increased primarily due to higher volumes of natural gas used partially offset by lower natural gas prices. In 2016, OG&E's fuel mix was 48.0 percent coal, 45.3 percent natural gas and 6.7 percent wind. In 2015, OG&E's fuel mix was 49.0 percent coal, 44.0 percent natural gas and seven percent wind.
(B) Decreased primarily due to a decrease in purchases from the SPP.
(C) Increased primarily due to higher SPP charges for the base plan projects of other utilities and SPP charges for the Windspeed Transmission line for the years 2008 through August 2016.

Other operation and maintenance expense increased $25.3 million, or 5.7 percent, in 2016 as compared to 2015. The below factors contributed to the change in other operation and maintenance expense:

(In millions)		Change
Salaries and wages (A)	$	10.4
Contract professional services (B)		8.7
Corporate allocations and overheads (C)		8.1
Other		(1.9)
Change in other operation and maintenance expense	$	25.3

(A) Increased primarily due to increases in incentive compensation, pension expense, annual salaries and medical/dental expense, partially offset by a decrease in overtime.
(B) Increased primarily due to increased consulting costs associated with demand side management programs.
(C) Increased primarily due to additional direct support in information technology, facility direct support, strategy and marketing support.

Depreciation and amortization expense increased $16.5 million, or 5.5 percent, primarily due to additional assets being placed in service and amortization of deferred storm costs.

Taxes other than income taxes decreased $3.1 million, or 3.6 percent, due to increased capitalization of ad valorem taxes primarily associated with environmental projects.

Allowance for equity funds used during construction increased $5.9 million, or 71.1 percent, primarily due to higher construction work in progress balances resulting from increased spending for environmental projects.

Other income increased $3.1 million, or 23.3 percent, primarily due to an increase in the tax gross-up related to higher allowance for equity funds used during construction and an increase in interest income related to riders, partially offset by decreased guaranteed flat bill margins.

Other expense increased $1.3 million, or 81.3 percent, primarily due to increased other miscellaneous expenses, increased charitable donations during 2016 and an increase in consulting services.

Interest expense decreased $8.6 million, or 5.9 percent, primarily due to the retirement of senior notes in January 2016, partially offset by increased allowance for borrowed funds used during construction primarily associated with environmental projects.

Income tax expense increased $9.6 million, or 9.2 percent, primarily due to higher pre-tax operating income in addition to lower renewable energy credits.

OGE Holdings (Natural Gas Midstream Operations)

	Year Ended December 31,		
(In millions)	**2017**	2016	2015
Operating revenues	**$ —**	$ —	$ —
Cost of sales	**—**	—	—
Other operation and maintenance	**0.3**	7.7	7.5
Depreciation and amortization	**—**	—	—
Taxes other than income	**1.0**	—	—
Operating loss	**(1.3)**	(7.7)	(7.5)
Equity in earnings of unconsolidated affiliates (A)	**131.2**	101.8	15.5
Other income	**0.1**	0.1	0.4
Income before taxes	**130.0**	**94.2**	**8.4**
Income tax (benefit) expense (B)	**(195.2)**	40.5	(1.0)
Net income attributable to OGE Holdings	**$ 325.2**	**$ 53.7**	**$ 9.4**

(A) The Company recorded a $108.4 million pre-tax charge during the third quarter of 2015 for its share of Enable's goodwill impairment, as adjusted for the basis difference. See Note 3 in "Item 8. Financial Statements and Supplementary Data" for further discussion of the goodwill impairment.
(B) Includes an income tax benefit of $245.2 million due to the remeasurement of deferred taxes, as a result of the 2017 Tax Act.

Reconciliation of Equity in Earnings of Unconsolidated Affiliates

The following table reconciles OGE Energy's equity in earnings of its unconsolidated affiliates for the years ended December 31, 2017 and 2016.

	Year Ended December 31,		
(In millions)	**2017**	2016	2015
Enable net income (loss)	**$ 400.3**	$ 289.5	$ (752.0)
Distributions senior to limited partners	**—**	(9.1)	—
Differences due to timing of OGE Energy and Enable accounting close	**—**	(12.2)	12.1
Enable net income (loss) used to calculate OGE Energy's equity in earnings	**$ 400.3**	$ 268.2	$ (739.9)
OGE Energy's percent ownership at period end	**25.7%**	25.7%	26.3%
OGE Energy's portion of Enable net income (loss)	**$ 102.7**	$ 70.7	$ (194.4)
Impairments recognized by Enable associated with OGE Energy's basis differences	**—**	2.6	178.4
OGE Energy's share of Enable net income (loss)	**102.7**	73.3	(16.0)
Amortization of basis difference	**11.3**	11.6	13.5
Elimination of Enable fair value step up	**17.2**	16.9	18.0
Equity in earnings of unconsolidated affiliates	**$ 131.2**	$ 101.8	$ 15.5

Equity in earnings of unconsolidated affiliates includes the Company's share of Enable earnings adjusted for the amortization of the basis difference of the Company's investment in Enogex LLC and its underlying equity in the net assets of Enable and is also adjusted for the elimination of the Enogex Holdings fair value adjustments.

The difference between OGE Energy's investment in Enable and its underlying equity in the net assets of Enable was $714.2 million as of December 31, 2017. The basis difference is being amortized over approximately 30 years, beginning in May 2013. The following table reconciles the basis difference in Enable from December 31, 2016 to December 31, 2017.

(In millions)	
Basis difference as of December 31, 2016	$ 743.7
Change in Enable basis difference	(1.0)
Amortization of basis difference	(11.3)
Elimination of Enable fair value step up	(17.2)
Basis difference as of December 31, 2017	$ 714.2

Enable Results of Operations

The following tables represents summarized financial information of Enable for 2017, 2016 and 2015:

	Year Ended December 31,		
(In millions)	**2017**	2016	2015
Operating revenues	**$ 2,803**	$ 2,272	$ 2,418
Cost of natural gas and NGLs	**1,381**	1,017	1,097
Operating income (loss)	**528**	385	(712)
Net income (loss)	**400**	290	(752)

	Year Ended December 31,		
	2017	2016	2015
Gathered volumes - TBtu/d	**3.56**	3.13	3.14
Transportation volumes - TBtu/d	**5.04**	4.88	4.97
Natural gas processed volumes - TBtu/d	**1.96**	1.80	1.78
NGLs sold - MBbl/d (A)(B)	**92.21**	78.16	75.55

(A) Excludes condensate.
(B) NGLs sold includes volumes of NGLs withdrawn from inventory or purchased for system balancing purposes.

Year Ended December 31, 2017 as compared to Year Ended December 31, 2016

OGE Holdings' earnings before taxes increased $35.8 million for the year ended December 31, 2017 as compared to the same period in 2016, primarily due to an increase in equity in earnings of Enable of $29.4 million and a decrease in pension settlement expense of $6.8 million. The increase in the Company's equity in earnings of Enable was primarily attributable to a $143.0 million increase in Enable's operating income. Enable's operating income increased primarily due to an increase in gross margin of $167.0 million and a decrease in impairments of $9.0 million that increased the Company's equity in earnings of Enable by $42.9 million and $2.3 million, respectively, partially offset by an increase in depreciation and amortization expense of $28.0 million, an increase in interest expense of $21.0 million and an increase in preferred distributions of $14.0 million that decreased the Company's equity in earnings of Enable by $7.2 million, $5.4 million and $3.6 million, respectively.

Enable's gathering and processing business segment reported an increase in operating income of $131.0 million. The increase in operating income was primarily due to an increase in gross margin of $160.0 million that increased the Company's equity in earnings of Enable by $41.1 million. The increase in gross margin was partially offset by an increase in depreciation and amortization expense of $20.0 million and an increase in operations and maintenance and general and administrative expenses of $13.0 million that decreased the Company's equity in earnings of Enable by $5.1 million and $3.3 million, respectively. Gathering and processing gross margin increased primarily due to an increase in gross margin from natural gas sales due to higher average natural gas prices and higher gathering volumes in the Anadarko and Ark-La-Tex Basins, an increase in processing margins resulting from higher average NGL prices and higher processed volumes in the Anadarko Basin, an increase in gathering margin due to increased gathering volumes in the Anadarko and Ark-La-Tex Basins and increased billings under minimum volume commitments in the Arkoma Basin and an increase in gross margin from changes in the fair value of condensate and NGL derivatives.

Enable's transportation and storage business segment reported an increase in operating income of $13.0 million. The increase in operating income was primarily due to a decrease in operations and maintenance and general and administrative expenses of $12.0 million and an increase in gross margin of $10.0 million that increased the Company's equity in earnings of Enable by $3.1 million and $2.6 million, respectively. These increases were partially offset by an increase of depreciation and amortization expense of $8.0 million that decreased the Company's equity in earnings of Enable by $2.1 million. Transportation and storage gross margin increased primarily due to an increase in gross margin from changes in the fair value of natural gas derivatives, an increase in NGL sales due to an increase in transported volumes and NGL prices and an increase in off-system transportation margins. These increases were partially offset by a decrease in system management activities, a decrease in firm transportation services between Carthage, Texas and Perryville, Louisiana and a decrease in realized gains on natural gas derivatives.

Income tax benefit was $195.2 million during the year ended December 31, 2017 as compared to income tax expense of $40.5 million during the same period in 2016. The change is primarily due to a remeasurement of federal deferred taxes related to the 2017 Tax Act, a remeasurement of state deferred taxes and return to provision adjustments related to the Company's investment in Enable during the year ended December 31, 2016, offset by higher pre-tax operating income.

Year Ended December 31, 2016 as compared to Year Ended December 31, 2015

OGE Holdings' earnings before taxes increased $85.8 million for the year ended December 31, 2016 as compared to the same period of 2015, primarily due to an increase in equity in earnings of Enable of $86.3 million. The increase in the Company's equity in earnings of Enable was primarily attributable to an increase of $1.097 billion in Enable's operating income during the year ended December 31, 2016 as compared to 2015. This increase was primarily due to goodwill and asset impairments recorded by Enable in 2015 of $1.125 billion, which resulted in the Company recognizing a $108.4 million goodwill impairment during 2015, as adjusted for basis differences. In addition, a decrease in operation and maintenance expense that includes administrative expense of $56.0 million increased the Company's equity in earnings of Enable by approximately $15.0 million and was partially offset by a decrease in Enable's gross margin of $66.0 million that decreased the Company's equity in earnings of Enable by $17.0 million.

Enable's gathering and processing business segment reported an increase in operating income of $499 million. Goodwill and asset impairments recorded in 2015 positively impacted operating income by $534 million in 2016. Absent the impact of such impairment, operating income decreased $35 million primarily due to a reduction in gross margin of $33 million and an increase in depreciation and amortization expense of $17 million that decreased the Company's equity in earnings of Enable by $9 million and $4 million, respectively. These changes were partially offset by a decrease of $17 million in operation and maintenance expenses that increased the Company's equity in earnings of Enable by $4 million. Gathering and processing gross margin decreased primarily due to lower commodity prices and a decrease due to one-time project reimbursements partially offset by increased volumes in the Williston Basin, increased billings under minimum volume commitments, higher rates on fee-based gathering services and an increase in the imbalance receivable associated with the annual fuel rate determination.

Enable's transportation and storage segment reported an increase in operating income of $601 million. Goodwill and asset impairments recorded in 2015 represented $591 million of this increase; further, a decrease of $39 million in operation and maintenance expense increased the Company's equity in earnings of Enable by $10 million. These increases were partially offset by a decrease in gross margin of $29 million that decreased the Company's equity in earnings of Enable by $8 million, primarily due to lower margin on unrealized natural gas derivatives, lower system management activities and lower firm transportation revenues partially offset by an increase in gross margin from transportation services for local distribution companies.

Over the course of 2015 and continuing into 2016, natural gas and crude oil prices have dropped to their lowest levels in over 10 years. Should lower commodity prices persist, or should commodity prices decline further, Enable's future operating results and cash flows could be negatively impacted.

Income tax expense was $40.5 million in 2016 as compared to a benefit of $1.0 million in 2015, an increase in expense of $41.5 million primarily due to higher pre-tax operating income and a state deferred tax revaluation resulting from a change in state tax rates.

Off-Balance Sheet Arrangement

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with a purchase option, covering 1,243 rotary gondola railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to fuel expense and are recovered through OG&E's tariffs and fuel adjustment clauses.

On December 17, 2015, OG&E renewed the lease agreement effective February 1, 2016. At the end of the new lease term, which is February 1, 2019, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $18.2 million. OG&E is also required to maintain all of the railcars it has under the operating lease.

Liquidity and Capital Resources

Working Capital

Working capital is defined as the difference in current assets and current liabilities. The Company's working capital requirements are driven generally by changes in accounts receivable, accounts payable, commodity prices, credit extended to and the timing of collections from customers, the level and timing of spending for maintenance and expansion activity, inventory levels and fuel recoveries.

Accounts Receivable and Accrued Unbilled Revenues. The balance of Accounts Receivable and Accrued Unbilled Revenues was $257.1 million and $235.2 million at December 31, 2017 and 2016, respectively, an increase of $21.9 million, or 9.3 percent, primarily due to an increase in billings to OG&E's retail customers.

Other Current Assets. The balance of Other Current Assets was $54.6 million and $81.8 million at December 31, 2017 and 2016, respectively, a decrease of $27.2 million, or 33.3 percent, primarily due to increased revenue collections from customers associated with various rate riders.

Short-Term Debt. The balance of Short-term Debt was $168.4 million and $236.2 million at December 31, 2017 and 2016, respectively, a decrease of $67.8 million, or 28.7 percent. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The decrease in 2017 compared to 2016 was primarily due to the repayment of short-term debt from the proceeds of the senior notes issuance in both March and August 2017.

Accounts Payable. The balance of Accounts Payable was $230.4 million and $205.4 million at December 31, 2017 and 2016, respectively, an increase of $25.0 million, or 12.2 percent, primarily due to the timing of vendor payments and accruals, partially offset by a decrease in fuel and purchased power payables.

Accrued Compensation. The balance of Accrued Compensation was $35.9 million and $45.1 million at December 31, 2017 and 2016, respectively, a decrease of $9.2 million, or 20.4 percent, primarily due to lower accruals for incentive compensation payouts.

Long-Term Debt Due Within One Year. The balance of Long-Term Debt Due Within One Year was $249.8 million and $224.7 million at December 31, 2017 and 2016, respectively, an increase of $25.1 million, or 11.2 percent, primarily due to the reclassification of long-term debt that will mature on September 1, 2018, partially offset by debt that matured July 15, 2017 and November 24, 2017.

Fuel Clause Recoveries. The balance of Fuel Clause Over Recoveries was $1.7 million at December 31, 2017 compared to a Fuel Clause Under Recoveries balance of $51.3 million at December 31, 2016. The change is primarily due to higher recoveries from OG&E retail customers as compared to the actual cost of fuel and purchased power.

Other Current Liabilities. The balance of Other Current Liabilities was $28.7 million and $96.0 million at December 31, 2017 and 2016, respectively, a decrease of $67.3 million, or 70.1 percent, primarily due to amounts refunded to customers in 2017.

Cash Flows

Year Ended December 31 *(In millions)*	**2017**	2016	2015	**2017 vs. 2016 $ Change**	**2017 vs. 2016 % Change**	2016 vs. 2015 $ Change	2016 vs. 2015 % Change
Net cash provided from operating activities	**$ 784.5**	$ 644.7	$ 867.1	**$ 139.8**	**21.7%**	$ (222.4)	(25.6)%
Net cash used in investing activities	**(821.9)**	(620.4)	(500.1)	**(201.5)**	**32.5%**	(120.3)	24.1 %
Net cash provided from (used in) financing activities	**51.5**	(99.2)	(297.3)	**150.7**	*****	198.1	(66.6)%

* Greater than a 100 percent variance.

Operating Activities

The increase of $139.8 million, or 21.7 percent, in net cash provided from operating activities in 2017 as compared to 2016 was primarily due to increased amounts received from customers, primarily due to recovery of fuel costs, and increased equity in earnings of Enable, partially offset by an increase in vendor payments. Cash distributions from Enable did not change compared to prior year; however, the increase in equity in earnings of Enable resulted in an increased portion of the cash distributions being classified as a return on investment in operating activities as opposed to the prior year classification as a return of investment in investing activities.

The decrease of $222.4 million, or 25.6 percent, in net cash provided from operating activities in 2016 as compared to 2015 was primarily due to a return of cash from fuel over recoveries to customers at OG&E.

Investing Activities

The increase of $201.5 million, or 32.5 percent, in net cash used in investing activities in 2017 as compared to 2016 was primarily due to an increase in capital expenditures related to environmental projects at OG&E and a decrease in return of investment. An increase in equity in earnings of Enable resulted in an increased portion of cash distributions from Enable being classified as a return on investment in operating activities as opposed to the prior year classification as a return of investment in investing activities.

The increase of $120.3 million, or 24.1 percent, in net cash used in investing activities in 2016 as compared to 2015 was primarily due to an increase in capital expenditures related to environmental projects at OG&E.

Financing Activities

The increase of $150.7 million in net cash provided from financing activities in 2017 as compared to 2016 was primarily due to the issuance by OG&E of $300.0 million in long-term debt in each of March 2017 and August 2017, partially offset by a decrease in short-term debt and the payment of $100.0 million in long-term debt in November 2017.

The decrease of $198.1 million, or 66.6 percent, in net cash used in financing activities in 2016 as compared to 2015 was primarily due to an increase in short-term debt, partially offset by the payment of $110.0 million in long-term debt during the first quarter of 2016.

2017 Capital Requirements, Sources of Financing and Financing Activities

Total capital requirements, consisting of capital expenditures and maturities of long-term debt, were $1,049.2 million, and contractual obligations, net of recoveries through fuel adjustment clauses, were $78.8 million, resulting in total net capital requirements and contractual obligations of $1,128.0 million in 2017, of which $213.9 million was to comply with environmental regulations. This compares to net capital requirements of $770.3 million and net contractual obligations of $82.6 million totaling $852.9 million in 2016, of which $135.8 million was to comply with environmental regulations.

In 2017, the Company's primary sources of capital were cash generated from operations, proceeds from the issuance of short-term debt and distributions from Enable. Changes in working capital reflect the seasonal nature of the Company's business, the revenue lag between billing and collection from customers and fuel inventories. See "Working Capital" for a discussion of significant changes in net working capital requirements as it pertains to operating cash flow and liquidity.

The Dodd-Frank Act

Derivative instruments have been used at times in managing OG&E's commodity price exposure. The Dodd-Frank Act, among other things, provides for regulation by the Commodity Futures Trading Commission of certain commodity-related contracts. Although OG&E qualifies for an end-user exception from mandatory clearing of commodity-related swaps, these regulations could affect the ability of OG&E to participate in these markets and could add additional regulatory oversight over its contracting activities.

Future Capital Requirements

The Company's primary needs for capital are related to acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E. Other working capital requirements are expected to be primarily related to maturing debt, operating lease obligations, fuel clause under and over recoveries and other general corporate purposes. The Company generally meets its cash needs through a combination of cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings.

Capital Expenditures

The Company's consolidated estimates of capital expenditures for the years 2018 through 2022 are shown in the following table. These capital expenditures represent the base maintenance capital expenditures (i.e., capital expenditures to maintain and operate the Company's businesses) plus capital expenditures for known and committed projects. Estimated capital expenditures for Enable are not included in the table below.

(In millions)	2018	2019	2020	2021	2022
Transmission (A)	$ 90	$ 50	$ 50	$ 50	$ 50
Distribution:					
Oklahoma	215	165	165	165	165
Arkansas	10	20	50	60	60
Generation	55	130	95	75	75
Other	50	25	25	25	25
Total Transmission, Distribution, Generation and Other	420	390	385	375	375
Projects:					
Environmental - Dry Scrubbers (B)	95	20	—	—	—
Combustion turbines - Mustang	35	—	—	—	—
Environmental - natural gas conversion (B)	35	15	—	—	—
Allowance of funds used during construction and ad valorem taxes	40	—	—	—	—
Grid modernization, reliability, resiliency, technology and other	—	200	190	280	180
Total Projects	205	235	190	280	180
Total	$ 625	$ 625	$ 575	$ 655	$ 555

(A) Future transmission capital expenditures include the following:

Project Type	Project Description	Estimated Cost (In millions)	Projected In-Service Date
Integrated Transmission Project	126 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to OG&E's Cimarron substation and construction of the Mathewson substation on this transmission line. $150.0 million has been spent prior to 2018.	$158	First quarter 2018

(B) Represent capital costs associated with OG&E's ECP to comply with the EPA's Regional Haze Rule. More detailed discussion regarding the Regional Haze Rule and OG&E's ECP can be found in Note 14 in "Item 8. Financial Statements and Supplementary Data" and in "Environmental Laws and Regulations" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in electric transmission assets, will be evaluated based upon their impact upon achieving the Company's financial objectives.

Contractual Obligations

The following table summarizes the Company's contractual obligations at December 31, 2017. See the Company's Consolidated Statements of Capitalization and Note 13 in "Item 8. Financial Statements and Supplementary Data" for additional information.

(In millions)	2018	2019-2020	2021-2022	After 2022	Total
Maturities of long-term debt (A)	$ 250.1	$ 250.2	$ 0.2	$ 2,529.6	$ 3,030.1
Operating lease obligations:					
Railcars	1.7	20.9	—	—	22.6
Wind farm land leases	2.5	5.4	5.8	40.6	54.3
Noncancellable operating lease	0.6	—	—	—	0.6
Total operating lease obligations	4.8	26.3	5.8	40.6	77.5
Other purchase obligations and commitments:					
Cogeneration capacity and fixed operation and maintenance payments	72.8	118.5	94.9	1.6	287.8
Expected cogeneration energy payments	35.7	71.5	75.4	0.9	183.5
Minimum fuel purchase commitments	139.8	60.8	49.2	382.7	632.5
Expected wind purchase commitments	58.7	113.4	115.1	505.0	792.2
Long-term service agreement commitments	7.9	44.3	4.8	123.1	180.1
Mustang Modernization expenditures	24.9	—	—	—	24.9
Environmental compliance plan expenditures	63.0	9.1	—	—	72.1
Total other purchase obligations and commitments	402.8	417.6	339.4	1,013.3	2,173.1
Total contractual obligations	657.7	694.1	345.4	3,583.5	5,280.7
Amounts recoverable through fuel adjustment clause (B)	(235.9)	(266.6)	(239.7)	(888.6)	(1,630.8)
Total contractual obligations, net	$ 421.8	$ 427.5	$ 105.7	$ 2,694.9	$ 3,649.9

(A) Maturities of the Company's long-term debt during the next five years consist of $250.1 million, $250.1 million, $0.1 million, $0.1 million and $0.1 million in 2018, 2019, 2020, 2021 and 2022, respectively.

(B) Includes expected recoveries of costs incurred for OG&E's railcar operating lease obligations, OG&E's expected cogeneration energy payments, OG&E's minimum fuel purchase commitments and OG&E's expected wind purchase commitments.

OG&E also has 440 MWs of QF contracts to meet its current and future expected customer needs. OG&E will continue reviewing all of the supply alternatives to these QF contracts that minimize the total cost of generation to its customers, including exercising its options (if applicable) to extend these QF contracts at pre-determined rates.

The actual cost of fuel used in electric generation (which includes the operating lease obligations for OG&E's railcar leases shown above) and certain purchased power costs are passed through to OG&E's customers through fuel adjustment clauses. Accordingly, while the cost of fuel related to operating leases and the vast majority of minimum fuel purchase commitments of OG&E noted above may increase capital requirements, such costs are recoverable through fuel adjustment clauses and have little, if any, impact on net capital requirements and future contractual obligations. The fuel adjustment clauses are subject to periodic review by the OCC and the APSC.

Pension and Postretirement Benefit Plans

At December 31, 2017, 35.6 percent of the Pension Plan investments were in listed common stocks with the balance primarily invested in corporate fixed income, other securities and U.S. Treasury notes and bonds as presented in Note 11 in "Item 8. Financial Statements and Supplementary Data." During 2017, actual returns on the Pension Plan were $84.4 million, compared to expected return on plan assets of $42.6 million. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, decreased. Funding levels are dependent on returns on plan assets and future discount rates. The Company made a $20.0 million contribution to its Pension Plan in both 2017 and 2016. The Company has not determined whether it will need to make any contributions to the Pension Plan in 2018. The Company could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future.

The following table presents the status of the Company's Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans at December 31, 2017 and 2016. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion, which is recorded as a regulatory asset as discussed in Note 1 in "Item 8. Financial Statements and Supplementary Data") in the Company's Consolidated Balance Sheets. The amounts in Accumulated Other Comprehensive Loss and those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

	Pension Plan		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
December 31 *(In millions)*	**2017**	2016	**2017**	2016	**2017**	2016
Benefit obligations	**$ 687.5**	$ 672.2	**$ 8.1**	$ 7.0	**$ 149.4**	$ 215.9
Fair value of plan assets	**635.3**	595.9	**—**	—	**50.2**	53.1
Funded status at end of year	**$ (52.2)**	$ (76.3)	**$ (8.1)**	$ (7.0)	**$ (99.2)**	$ (162.8)

Common Stock Dividends

The Company's dividend policy is reviewed by the Board of Directors at least annually and is based on numerous factors, including management's estimation of the long-term earnings power of its businesses. The Company's financial objective includes dividend increases of approximately 10 percent annually through 2019. The targeted annual dividend increase has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets and the composition of the Company's assets and investment opportunities. At the Company's September 2017 board meeting, the Board of Directors approved management's recommendation of a 10 percent increase in the quarterly dividend rate to $0.3325 per share from $0.3025 per share effective in October 2017.

Financing Activities and Future Sources of Financing

Management expects that cash generated from operations, proceeds from the issuance of long and short-term debt, proceeds from the sales of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan or other offerings and distributions from Enable will be adequate over the next three years to meet anticipated cash needs and to fund future growth opportunities. The Company utilizes short-term borrowings (through a combination of bank borrowings and commercial paper) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

Short-Term Debt and Credit Facilities

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreement. In March 2017, the Company and OG&E each entered into new $450.0 million unsecured revolving credit agreements which expire March 2022. These bank facilities can also be used as letter of credit facilities. As of December 31, 2017, the Company had $168.4 million of short-term debt compared to $236.2 million at December 31, 2016. The average balance of short-term debt in 2017 was $175.7 million at a weighted-average interest rate of 1.30 percent. The maximum month-end balance of short-term debt in 2017 was $260.1 million. At December 31, 2017, the Company had $731.3 million of net available liquidity under its revolving credit agreements. OG&E has the necessary regulatory approvals to incur up to $800.0 million in short-term borrowings at any one time for a two-year period beginning January 1, 2017 and ending December 31, 2018. At December 31, 2017, the Company had $14.4 million in cash and cash equivalents. See Note 10 in "Item 8. Financial Statements and Supplementary Data" for further discussion.

Issuance of Long-Term Debt

In March 2017, OG&E issued $300.0 million of 4.15 percent senior notes due April 1, 2047. The proceeds from the issuance were used for general corporate purposes, including to repay short-term debt, to repay borrowings under the revolving credit facility, to fund the payment of OG&E's $125.0 million of 6.5 percent senior notes that matured on July 15, 2017 and to fund ongoing capital expenditures and working capital.

In August 2017, OG&E issued $300.0 million of 3.85 percent senior notes due August 15, 2047. The proceeds from the issuance were used for general corporate purposes, including to repay short-term debt, to repay borrowings under the revolving credit facility and to fund ongoing capital expenditures and working capital.

Security Ratings

	Moody's Investors Services	Standard & Poor's Ratings Services	Fitch Ratings
OG&E Senior Notes	A1	A-	A+
OGE Energy Senior Notes	A3	BBB+	A-
OGE Energy Commercial Paper	P2	A2	F2

Access to reasonably priced capital is dependent in part on credit and security ratings. Generally, lower ratings lead to higher financing costs. Pricing grids associated with the Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse rating impact occurs. The impact of any future downgrade could include an increase in the costs of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post collateral or letters of credit.

A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency, and each rating should be evaluated independently of any other rating.

On June 29, 2017, Moody's Investors Service revised the rating outlooks on the Company and OG&E from stable to negative. Moody's Investors Service indicated that the revised outlooks reflect the potential for a decline in financial metrics amidst some uncertainty over cost recovery and earned returns in Oklahoma. The revised outlooks did not trigger any collateral requirements or change fees under the revolving credit agreements.

Future financing requirements may be dependent, to varying degrees, upon numerous factors such as general economic conditions, abnormal weather, load growth, commodity prices, acquisitions of other businesses and/or development of projects, actions by rating agencies, inflation, changes in environmental laws or regulations, rate increases or decreases allowed by regulatory agencies, new legislation and market entry of competing electric power generators.

Common Stock

The Company does not expect to issue any common stock in 2018 from its Automatic Dividend Reinvestment and Stock Purchase Plan. See Note 8 in "Item 8. Financial Statements and Supplementary Data" for a discussion of the Company's common stock activity.

Distributions by Enable

Pursuant to the Enable Limited Partnership Agreement, Enable made distributions of $141.2 million, $141.2 million and $139.3 million to the Company during the years ended December 31, 2017, 2016 and 2015, respectively. On June 22, 2016, Enable's Limited Partnership Agreement was amended to change the last permitted distribution date from 45 days to 60 days after the close of each quarter. Enable's General Partner Agreement was amended to change the distribution deadline from 50 days after the close of each quarter to five days following distributions by Enable.

Critical Accounting Policies and Estimates

The Consolidated Financial Statements and Notes to Consolidated Financial Statements contain information that is pertinent to Management's Discussion and Analysis. In preparing the Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets

and contingent liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's Consolidated Financial Statements. However, the Company believes it has taken reasonable positions where assumptions and estimates are used in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised includes the determination of Pension Plan assumptions, income taxes, contingency reserves, asset retirement obligations and depreciable lives of property, plant and equipment. For the electric utility segment, significant judgment is also exercised in the determination of regulatory assets and liabilities and unbilled revenues. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Company's Audit Committee. The Company discusses its significant accounting policies, including those that do not require management to make difficult, subjective or complex judgments or estimates, in Note 1 in "Item 8. Financial Statements and Supplementary Data."

Pension and Postretirement Benefit Plans

The Company has a Pension Plan that covers a significant amount of the Company's employees hired before December 1, 2009. Effective December 1, 2009, the Company's Pension Plan is no longer being offered to employees hired on or after December 1, 2009. The Company also has defined benefit postretirement plans that cover a significant amount of its employees. Pension and other postretirement plan expenses and liabilities are determined on an actuarial basis and are affected by the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and the level of funding. Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension expense ultimately recognized. The Pension Plan rate assumptions are shown in Note 11 in "Item 8. Financial Statements and Supplementary Data." The assumed return on plan assets is based on management's expectation of the long-term return on the plan assets portfolio. The discount rate used to compute the present value of plan liabilities is based generally on rates of high-grade corporate bonds with maturities similar to the average period over which benefits will be paid. Funding levels are dependent on returns on plan assets and future discount rates. Higher returns on plan assets and an increase in discount rates will reduce funding requirements to the Pension Plan. The following table indicates the sensitivity of the Pension Plan funded status to these variables.

	Change	Impact on Funded Status
Actual plan asset returns	+/- 1 percent	+/- $6.4 million
Discount rate	+/- 0.25 percent	+/- $12.9 million
Contributions	+/- $10 million	+/- $10.0 million

Income Taxes

The Company uses the asset and liability method of accounting for income taxes. Under this method, a deferred tax asset or liability is recognized for the estimated future tax effects attributable to temporary differences between the financial statement basis and the tax basis of assets and liabilities as well as tax credit carry forwards and net operating loss carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period of the change.

The application of income tax law is complex. Laws and regulations in this area are voluminous and often ambiguous. Interpretations and guidance surrounding income tax laws and regulations change over time. Accordingly, it is necessary to make judgments regarding income tax exposure. As a result, changes in these judgments can materially affect amounts the Company recognized in its consolidated financial statements. Tax positions taken by the Company on its income tax returns that are recognized in the financial statements must satisfy a more likely than not recognition threshold, assuming that the position will be examined by taxing authorities with full knowledge of all relevant information.

On December 22, 2017, President Trump signed the 2017 Tax Act into law, significantly changing U.S. corporate income tax laws. The 2017 Tax Act reduces the corporate federal tax rate from 35 percent to 21 percent for tax years beginning after December 31, 2017. See Note 7 in "Item 8. Financial Statements and Supplementary Data" for further discussion of the effects of the 2017 Tax Act.

Asset Retirement Obligations

The Company has recorded asset retirement obligations that are being accreted over their respective lives ranging from three to 74 years. The inputs used in the valuation of asset retirement obligations include the assumed life of the asset placed into service, the average inflation rate, market risk premium, the credit-adjusted risk free interest rate and the timing of incurring costs related to the retirement of the asset.

Regulatory Assets and Liabilities

OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide that certain incurred costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

OG&E records certain incurred costs and obligations as regulatory assets or liabilities if, based on regulatory orders or other available evidence, it is probable that the costs or obligations will be included in amounts allowable for recovery or refund in future rates. The benefit obligations regulatory asset is comprised of expenses recorded which are probable of future recovery and that have not yet been recognized as components of net periodic benefit cost, including net loss and prior service cost.

See Note 1 and Note 7 in "Item 8. Financial Statements and Supplementary Data" for further discussion of the 2017 Tax Act's impact on OG&E's regulatory assets and liabilities as of December 31, 2017.

Unbilled Revenues

OG&E recognizes revenue from electric sales when power is delivered to customers. OG&E reads its customers' meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. OG&E accrues an estimate of the revenues for electric sales delivered since the latest billings. Unbilled revenue is presented in Accrued Unbilled Revenues on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income based on estimates of usage and prices during the period. At December 31, 2017, if the estimated usage or price used in the unbilled revenue calculation were to increase or decrease by one percent, this would cause a change in the unbilled revenues recognized of $0.5 million. At December 31, 2017 and 2016, Accrued Unbilled Revenues were $66.5 million and $59.7 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Allowance for Uncollectible Accounts Receivable

Customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable for OG&E is calculated by multiplying the last six months of electric revenue by the provision rate, which is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. Also, a portion of the uncollectible provision related to fuel within the Oklahoma jurisdiction is being recovered through the fuel adjustment clause. At December 31, 2017, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of $0.1 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in the Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was $1.5 million at both December 31, 2017 and 2016.

Accounting Pronouncements

See Note 2 in "Item 8. Financial Statements and Supplementary Data" for discussion of current accounting pronouncements that are applicable to the Company.

Commitments and Contingencies

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other experts to assess the claim. If, in management's opinion, the Company has

incurred a probable loss as set forth by GAAP, an estimate is made of the loss, and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. At the present time, based on available information, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. See Note 13 in "Item 8. Financial Statements and Supplementary Data" and "Item 3. Legal Proceedings" for a discussion of the Company's commitments and contingencies.

Environmental Laws and Regulations

The activities of the Company are subject to numerous stringent and complex federal, state and local laws and regulations governing environmental protection. These laws and regulations can change, restrict or otherwise impact OG&E's business activities in many ways, including the handling or disposal of waste material, planning for future construction activities to avoid or mitigate harm to threatened or endangered species and requiring the installation and operation of emissions control equipment. Failure to comply with these laws and regulations could result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Management believes that all of its operations are in substantial compliance with current federal, state and local environmental standards.

Environmental regulation can increase the cost of planning, design, initial installation and operation of OG&E's facilities. OG&E is managing several potentially material uncertainties about the scope and timing for the acquisition, installation and operation of additional pollution control equipment and compliance costs for a variety of the EPA rules that are being challenged in court. OG&E is unable to predict the financial impact of these matters with certainty at this time. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2018 will be $189.2 million, of which $170.0 million is for capital expenditures. It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2019 will be approximately $51.8 million, of which $35.2 million is for capital expenditures. The amounts for OG&E above include capital expenditures for Dry Scrubbers and conversion of two coal-fueled units to natural gas.

Air

Federal Clean Air Act Overview

OG&E’s operations are subject to the Federal Clean Air Act, as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including electric generating units, and also impose various monitoring and reporting requirements. Such laws and regulations may require that OG&E obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations or install emission control equipment. OG&E likely will be required to incur certain capital expenditures in the future for air pollution control equipment and technology in connection with obtaining and maintaining operating permits and approvals for air emissions.

Regional Haze Control Measures

The EPA's 2005 Regional Haze Rule is intended to protect visibility in certain national parks and wilderness areas throughout the U.S. that may be impacted by air pollutant emissions. On December 28, 2011, the EPA issued a final Regional Haze Rule for Oklahoma which adopted a FIP for SO_2 emissions at Sooner Units 1 and 2 and Muskogee Units 4 and 5. The FIP compliance date is January 4, 2019 as a result of an appeal filed by OG&E and others.

OG&E's strategy for satisfying the FIP includes installing Dry Scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas. As described in Note 14 in "Item 8. Financial Statements and Supplementary Data," the OCC has approved the Company's decision to install Dry Scrubbers at the Sooner units. As of December 31, 2017, OG&E has invested $401.3 million in the Dry Scrubbers and $13.0 million in the Muskogee gas conversion.

Cross-State Air Pollution Rule

In August 2011, the EPA finalized its CSAPR that required 27 states in the eastern half of the U.S. (including Oklahoma) to reduce power plant emissions that contribute to ozone and particulate matter pollution in other states. Litigation challenging the

rule prevented it from entering into effect until 2014. Several parties to that litigation, including OG&E, have petitions for review that remain pending although the rule is now effective. Compliance with the CSAPR began in 2015 using the amount of allowances originally scheduled to be available in 2012. As of December 31, 2017, OG&E has installed seven low NO_X burner systems on two Muskogee units, two Sooner units and three Seminole units and is in compliance.

On September 7, 2016, the EPA finalized an update to the 2011 CSAPR. The new rule applies to ozone-season NO_X in 22 eastern states (including Oklahoma), utilizes a cap and trade program for NO_X emissions and took effect on May 1, 2017. The rule reduces the 2016 CSAPR emissions cap for all seven of OG&E's coal and gas facilities by 47 percent combined. OG&E and numerous other parties filed petitions for judicial and administrative review of the 2016 rule. Those petitions all are pending without any relevant substantive decisions by the authorities.

Due to the pending litigation and administrative proceedings, the ultimate timing and impact of the 2016 CSAPR update rule on our operations cannot be determined with certainty at this time. However, the Company does not anticipate additional capital expenditures beyond what has already been disclosed and does not expect that the reduced emissions cap, if upheld, will have a material impact on the Company's consolidated financial position, results of operations or cash flows.

Hazardous Air Pollutants Emission Standards

On February 16, 2012, the EPA published the final MATS rule regulating the emissions of certain hazardous air pollutants from electric generating units, which became effective April 16, 2012. The Company believes that it complied with the MATS rule by the April 16, 2016 deadline that applied to OG&E. Nonetheless, there is continuing litigation, to which the Company is not a party, challenging whether the EPA had statutory authority to issue the MATS rule. The Company cannot predict the outcome of this litigation or how it will affect the Company.

National Ambient Air Quality Standards

The EPA is required to set NAAQS for certain pollutants considered to be harmful to public health or the environment. The Clean Air Act requires the EPA to review each NAAQS every five years. As a result of these reviews, the EPA periodically has taken action to adopt more stringent NAAQS for those pollutants. If any areas of Oklahoma were to be designated as not attaining the NAAQS for a particular pollutant, the Company could be required to install additional emission controls on its facilities to help the state achieve attainment with the NAAQS. As of the end of 2017, no areas of Oklahoma had been designated as non-attainment for pollutants that are likely to affect the Company's operations. Several processes are under way to designate areas in Oklahoma as attaining or not attaining revised NAAQS.

The EPA proposed to designate part of Muskogee County in which OG&E's Muskogee Power Plant is located as non-attainment for the 2010 SO_2 NAAQS on March 1, 2016, even though nearby monitors indicate compliance with the NAAQS. The proposed designation is based on modeling that does not reflect the planned conversion of two of the coal units at Muskogee to natural gas. OG&E commented that the EPA should defer a designation of the area to allow time for additional monitoring. The State of Oklahoma's revised monitoring plan was approved by the EPA, and the required monitoring commenced at the beginning of 2017 and will continue through the end of 2019. Nonetheless, the EPA has a deadline for making a decision on the designation pursuant to a consent decree entered by the U.S. District Court for the Northern District of California to resolve a citizen suit. The deadline has been extended several times, with the current deadline being August 26, 2017, but a decision has yet to be reached. It is unclear what impact, if any, the consent decree deadline will have on the monitoring plan. At this time, OG&E cannot determine with any certainty whether the proposed designation of Muskogee County will cause a material impact to OG&E's financial results. The EPA has published final decisions on all other areas of Oklahoma. In this decision, Noble County, in which the Sooner plant is located, was deemed to be in attainment with the 2010 standard.

On September 30, 2015, the EPA finalized a NAAQS for ozone at 70 ppb, which is more stringent than the previous standard of 75 ppb, set in 2008. In September 2016, Governor Mary Fallin submitted to the EPA the recommendation of "attainment/unclassifiable" for all 77 counties in Oklahoma. This recommendation is subject to approval by the EPA. In a letter to Oklahoma dated December 20, 2017, the EPA proposed to approve this recommendation.

The Company is monitoring those processes and their possible impact on its operations but, at this time, cannot determine with any certainty whether they will cause a material impact to the Company's financial results.

Climate Change and Greenhouse Gas Emissions

There is continuing discussion and evaluation of possible global climate change in certain regulatory and legislative arenas. The focus is generally on emissions of greenhouse gases, including CO_2, sulfur hexafluoride and methane, and whether these emissions are contributing to the warming of the earth's atmosphere. On June 1, 2017, President Trump announced that the U.S. will withdraw from the Paris Climate Accord and begin negotiations to re-enter the agreement with different terms. A new agreement may result in future additional emissions reductions in the U.S.; however, it is not possible to determine what the international legal standards for greenhouse gas emissions will be in the future and the extent to which these commitments will be implemented through the Clean Air Act or any other existing statutes and new legislation.

If legislation or regulations are passed at the federal or state levels in the future requiring mandatory reductions of CO_2 and other greenhouse gases on the Company's facilities, this could result in significant additional compliance costs that would affect the Company's future financial position, results of operations and cash flows if such costs are not recovered through regulated rates. Several states outside the area where the Company operates have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs.

On October 23, 2015, the EPA published the final Clean Power Plan that established standards of performance for CO_2 emissions from existing fossil-fuel-fired power plants along with state-specific CO_2 reduction standards expressed as both rate-based (lbs./MWh) and mass-based (tons/yr.) goals. However, the rule was challenged in court when it was issued, and the U.S. Supreme Court issued orders staying implementation of the Clean Power Plan on February 9, 2016 pending resolution of the court challenges. The EPA published a proposal on October 16, 2017 to repeal the Clean Power Plan. In addition, the EPA published an Advance Notice of Proposed Rulemaking seeking comments on regulatory options for replacing the Clean Power Plan. The ultimate timing and impact of these standards on OG&E's operations cannot be determined with certainty at this time, although a requirement for significant reduction of CO_2 emissions from existing fossil-fuel-fired power plants ultimately could result in significant additional compliance costs that would affect the Company's future consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates.

Nonetheless, OG&E's current business strategy will result in a reduced carbon emissions rate compared to current levels. As discussed in Note 14 in "Item 8. Financial Statements and Supplementary Data" under "Pending Regulatory Matters," OG&E's plan to comply with the EPA's MATS rule and Regional Haze Rule FIP includes converting two coal-fired generating units at the Muskogee Station to natural gas, among other measures. OG&E's deployment of Smart Grid technology helps to reduce the peak load demand. OG&E is also deploying more renewable energy sources that do not emit greenhouse gases. OG&E's service territory borders one of the nation's best wind resource areas, and OG&E has leveraged its geographic position to develop renewable energy resources and completed transmission investments to deliver the renewable energy. The SPP has begun to authorize the construction of transmission lines capable of bringing renewable energy out of the wind resource areas in western Oklahoma, the Texas Panhandle and western Kansas to load centers by planning for more transmission to be built in the area. In addition to increasing overall system reliability, these new transmission resources should provide greater access to additional wind resources that are currently constrained due to existing transmission delivery limitations.

EPA Startup, Shutdown and Malfunction Policy

On May 22, 2015, the EPA issued a final rule to address the provisions in the SIPs of 36 states (including Oklahoma) regarding the treatment of emissions that occur during startup, shutdown and malfunction operations. The final rule clarifies the EPA's Startup, Shutdown and Malfunction Policy. Although judicial challenges to the rule are ongoing, the Oklahoma Department of Environmental Quality submitted a SIP revision for the EPA's approval on November 7, 2016 to comply with this rule. This rule has resulted in permit modifications for certain OG&E units. The Company does not anticipate capital expenditures or a material impact to its consolidated financial position, results of operations or cash flows, as a result of adoption of this rule.

Air Quality Control System

On September 10, 2014, OG&E executed a contract for the design, engineering and fabrication of two circulating Dry Scrubber systems to be installed at Sooner Units 1 and 2. OG&E entered into an agreement on February 9, 2015 to install the Dry Scrubber systems. The Dry Scrubbers are expected to be completed in mid to late 2018. More detail regarding the ECP can be found under the "Pending Regulatory Matters" section of Note 14 in "Item 8. Financial Statements and Supplementary Data."

Endangered Species

Certain federal laws, including the Bald and Golden Eagle Protection Act, the Migratory Bird Treaty Act and the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for unpermitted activities that result in harm to or harassment of certain protected animals and plants, including damage to their habitats. If such species are located in an area in which the Company conducts operations, or if additional species in those areas become subject to protection, the Company's operations and development projects, particularly transmission, wind or pipeline projects, could be restricted or delayed, or the Company could be required to implement expensive mitigation measures.

Waste

OG&E's operations generate wastes that are subject to the Federal Resource Conservation and Recovery Act of 1976 as well as comparable state laws which impose detailed requirements for the handling, storage, treatment and disposal of waste.

On December 19, 2014, the EPA finalized a rule under the Federal Resource Conservation and Recovery Act for the handling and disposal of coal combustion residuals or coal ash. The final rule regulates coal ash as a solid waste rather than a hazardous waste, which would have made the management of coal ash more costly. The final rule is currently being appealed at the D.C. Circuit Court of Appeals. OG&E is in compliance with this rule at this time.

On January 16, 2018, the EPA proposed to approve the application from the State of Oklahoma to administer the Coal Combustion Residual rule in lieu of the "self-implementing" oversight authorities under the EPA coal ash rule of 2015. Oklahoma has incorporated all of the required elements of the EPA Coal Combustion Residual rule into the state permit program. Upon final approval by the EPA, the state Coal Combustion Residual program will operate in lieu of the self-implementing governance as per the final, 2015 EPA coal ash rule.

The Company has sought and will continue to seek pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2017, the Company obtained refunds of $2.1 million from the recycling of scrap metal, salvaged transformers and used transformer oil. This figure does not include the additional savings gained through the reduction and/or avoidance of disposal costs and the reduction in material purchases due to the reuse of existing materials. Similar savings are anticipated in future years.

Water

OG&E's operations are subject to the Federal Clean Water Act and comparable state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and federal waters.

The EPA issued a final rule on May 19, 2014 to implement Section 316(b) of the Federal Clean Water Act, which requires that power plant cooling water intake structure location, design, construction and capacity reflect the best available technology for minimizing their adverse environmental impact via the impingement and entrainment of aquatic organisms. OG&E submitted compliance plans to the State of Oklahoma in April 2015. On December 22, 2017, the Oklahoma Department of Environmental Quality issued a final permit for Muskogee Power Plant in compliance with the final 316(b) rule, which did not incur material cost. OG&E expects to be able to provide a reasonable estimate of any material costs associated with the rule's implementation at other facilities following the future issuance of permits from the State of Oklahoma.

On September 30, 2015, the EPA issued a final rule addressing the effluent limitation guidelines for power plants under the Federal Clean Water Act. The final rule establishes technology and performance based standards that may apply to discharges of six waste streams including bottom ash transport water. Compliance with this rule occurs between 2018 and 2023. OG&E is evaluating what, if any, compliance actions are needed but is not able to quantify with any certainty what costs may be incurred. OG&E expects to be able to provide a reasonable estimate of any material costs associated with the rule's implementation following issuance of the permits from the State of Oklahoma.

Site Remediation

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 and comparable state laws impose liability, without regard to the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Because OG&E utilizes various products and generate wastes that are considered hazardous substances for purposes of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, OG&E could be subject to liability for the costs of cleaning up and restoring sites where those substances have been released to the environment. At this time, it is not anticipated that any associated liability will cause a significant impact to OG&E.

For a further discussion regarding contingencies relating to environmental laws and regulations, see Note 13 in "Item 8. Financial Statements and Supplementary Data."

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Market risks are, in most cases, risks that are actively traded in a marketplace and have been well studied in regards to quantification. Market risks include, but are not limited to, changes in interest rates and commodity prices. The Company's exposure to changes in interest rates relates primarily to short-term variable-rate debt and commercial paper. The Company is exposed to commodity prices in its operations.

Risk Oversight Committee

Management monitors market risks using a risk committee structure. The Company's Risk Oversight Committee, which consists primarily of corporate officers, is responsible for the overall development, implementation and enforcement of strategies and policies for all market risk management activities of the Company. This committee's emphasis is a holistic perspective of risk measurement and policies targeting the Company's overall financial performance. On a quarterly basis, the Risk Oversight Committee reports to the Audit Committee of the Company's Board of Directors on the Company's risk profile affecting anticipated financial results, including any significant risk issues.

The Company also has a Corporate Risk Management Department. This group, in conjunction with the aforementioned committees, is responsible for establishing and enforcing the Company's risk policies.

Risk Policies

Management utilizes risk policies to control the amount of market risk exposure. These policies are designed to provide the Audit Committee of the Company's Board of Directors and senior executives of the Company with confidence that the risks taken on by the Company's business activities are in accordance with their expectations for financial returns and that the approved policies and controls related to market risk management are being followed.

Interest Rate Risk

The Company's exposure to changes in interest rates primarily relates to short-term variable-rate debt and commercial paper. The Company manages its interest rate exposure by monitoring and limiting the effects of market changes in interest rates. The Company may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce the effects of these changes. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio, but the Company has no intent at this time to utilize interest rate derivatives.

The fair value of the Company's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities or by calculating the net present value of the monthly payments discounted by the Company's current borrowing rate. The following table shows the Company's long-term debt maturities and the weighted-average interest rates by maturity date.

Year Ended December 31 *(Dollars in millions)*	2018	2019	2020	2021	2022	Thereafter	Total	12/31/17 Fair Value
Fixed-rate debt (A):								
Principal amount	$ 250.1	$ 250.1	$ 0.1	$ 0.1	$ 0.1	$ 2,394.2	$ 2,894.7	$ 3,252.6
Weighted-average interest rate	6.35%	8.25%	3.77%	3.77%	3.77%	4.90%	5.31%	
Variable-rate debt (B):								
Principal amount	$ —	$ —	$ —	$ —	$ —	$ 135.4	$ 135.4	$ 135.4
Weighted-average interest rate	—%	—%	—%	—%	—%	1.82%	1.82%	

(A) Prior to or when these debt obligations mature, the Company may refinance all or a portion of such debt at then-existing market interest rates which may be more or less than the interest rates on the maturing debt.

(B) A hypothetical change of 100 basis points in the underlying variable interest rate incurred by the Company would change interest expense by $1.4 million annually.

Item 8. Financial Statements and Supplementary Data.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31 *(In millions except per share data)*	**2017**	2016	2015
OPERATING REVENUES	**$ 2,261.1**	$ 2,259.2	$ 2,196.9
COST OF SALES	**897.6**	880.1	865.0
OPERATING EXPENSES			
Other operation and maintenance	**480.3**	465.6	451.6
Depreciation and amortization	**283.5**	322.6	307.9
Taxes other than income	**89.4**	87.6	91.2
Total operating expenses	**853.2**	875.8	850.7
OPERATING INCOME	**510.3**	503.3	481.2
OTHER INCOME (EXPENSE)			
Equity in earnings of unconsolidated affiliates	**131.2**	101.8	15.5
Allowance for equity funds used during construction	**39.7**	14.2	8.3
Other income	**46.4**	26.0	27.0
Other expense	**(14.1)**	(16.9)	(14.3)
Net other income	**203.2**	125.1	36.5
INTEREST EXPENSE			
Interest on long-term debt	**153.6**	143.2	147.8
Allowance for borrowed funds used during construction	**(18.0)**	(7.5)	(4.2)
Interest on short-term debt and other interest charges	**8.2**	6.4	5.4
Interest expense	**143.8**	142.1	149.0
INCOME BEFORE TAXES	**569.7**	486.3	368.7
INCOME TAX (BENEFIT) EXPENSE	**(49.3)**	148.1	97.4
NET INCOME	**$ 619.0**	$ 338.2	$ 271.3
BASIC AVERAGE COMMON SHARES OUTSTANDING	**199.7**	199.7	199.6
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**200.0**	199.9	199.6
BASIC EARNINGS PER AVERAGE COMMON SHARE	**$ 3.10**	$ 1.69	$ 1.36
DILUTED EARNINGS PER AVERAGE COMMON SHARE	**$ 3.10**	$ 1.69	$ 1.36
DIVIDENDS DECLARED PER COMMON SHARE	**$ 1.27000**	$ 1.15500	$ 1.05000

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 *(In millions)*	**2017**	2016	2015
Net income	**$ 619.0**	$ 338.2	$ 271.3
Other comprehensive income (loss), net of tax:			
Pension Plan and Restoration of Retirement Income Plan:			
Amortization of deferred net loss, net of tax of $1.4, $1.7 and $2.2, respectively	**2.5**	2.8	2.5
Amortization of prior service cost, net of tax of $0.0, $0.0 and $0.0, respectively	**(0.1)**	—	—
Net gain (loss) arising during the period, net of tax of $0.2, ($0.6) and ($5.8), respectively	**0.4**	(0.7)	(9.5)
Settlement cost, net of tax of $1.4, $3.2 and $2.9, respectively	**2.2**	5.0	4.6
Postretirement Benefit Plans:			
Amortization of prior service cost, net of tax of ($0.3), ($1.0) and ($1.1), respectively	**(0.6)**	(1.5)	(1.8)
Amortization of deferred net loss, net of tax of $0.0, $0.0 and $0.8, respectively	**—**	—	1.2
Prior service cost arising during the period, net of tax of $4.0, $0.0 and $0.0, respectively	**6.3**	—	—
Net (loss) gain arising during the period, net of tax of ($0.2), $0.1 and $5.6, respectively	**(0.6)**	0.2	9.3
Settlement cost, net of tax of $0.2, $0.0 and $0.0, respectively	**0.5**	—	—
Other comprehensive income, net of tax	**10.6**	5.8	6.3
Comprehensive income	**$ 629.6**	$ 344.0	$ 277.6

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 *(In millions)*	2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 619.0**	$ 338.2	$ 271.3
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation and amortization	**283.5**	322.6	307.9
Deferred income taxes and investment tax credits, net	**(50.0)**	153.8	102.6
Equity in earnings of unconsolidated affiliates	**(131.2)**	(101.8)	(15.5)
Distributions from unconsolidated affiliates	**131.2**	102.3	94.1
Allowance for equity funds used during construction	**(39.7)**	(14.2)	(8.3)
Stock-based compensation	**9.1**	4.7	7.6
Regulatory assets	**3.7**	(21.4)	(9.1)
Regulatory liabilities	**(3.7)**	(11.8)	(27.5)
Other assets	**(0.7)**	15.4	10.4
Other liabilities	**(65.5)**	(18.9)	8.6
Change in certain current assets and liabilities:			
Accounts receivable and accrued unbilled revenues, net	**(21.8)**	(6.9)	21.6
Income taxes receivable	**13.6**	(2.2)	(1.2)
Fuel, materials and supplies inventories	**(3.6)**	32.4	(56.5)
Fuel recoveries	**53.0**	(112.6)	129.6
Other current assets	**27.2**	(26.2)	(17.2)
Accounts payable	**27.1**	(45.1)	30.9
Other current liabilities	**(66.7)**	36.4	17.8
Net cash provided from operating activities	**784.5**	644.7	867.1
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(824.1)**	(660.1)	(547.8)
Investment in unconsolidated affiliates	**(8.5)**	—	—
Return of capital - equity method investments	**10.0**	38.8	45.2
Proceeds from sale of assets	**0.7**	0.9	2.5
Net cash used in investing activities	**(821.9)**	(620.4)	(500.1)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from long-term debt	**592.1**	—	—
Issuance (expense) of common stock	**(0.1)**	—	7.2
(Decrease) increase in short-term debt	**(67.8)**	236.2	(98.0)
Payment of long-term debt	**(225.1)**	(110.2)	(0.2)
Dividends paid on common stock	**(247.6)**	(225.1)	(204.6)
Other	**—**	(0.1)	(1.7)
Net cash provided from (used in) financing activities	**51.5**	(99.2)	(297.3)
NET CHANGE IN CASH AND CASH EQUIVALENTS	**14.1**	(74.9)	69.7
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**0.3**	75.2	5.5
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 14.4**	$ 0.3	$ 75.2

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2017**	2016
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 14.4**	$ 0.3
Accounts receivable, less reserve of $1.5 and $1.5, respectively	**188.7**	173.0
Accounts receivable - unconsolidated affiliates	**1.9**	2.5
Accrued unbilled revenues	**66.5**	59.7
Income taxes receivable	**5.8**	19.4
Fuel inventories	**84.3**	79.8
Materials and supplies, at average cost	**80.8**	81.7
Fuel clause under recoveries	**—**	51.3
Other	**54.6**	81.8
Total current assets	**497.0**	549.5
OTHER PROPERTY AND INVESTMENTS		
Investment in unconsolidated affiliates	**1,160.4**	1,158.6
Other	**76.7**	73.6
Total other property and investments	**1,237.1**	1,232.2
PROPERTY, PLANT AND EQUIPMENT		
In service	**11,041.2**	10,690.0
Construction work in progress	**867.5**	495.1
Total property, plant and equipment	**11,908.7**	11,185.1
Less accumulated depreciation	**3,568.8**	3,488.9
Net property, plant and equipment	**8,339.9**	7,696.2
DEFERRED CHARGES AND OTHER ASSETS		
Regulatory assets	**283.0**	404.8
Other	**55.7**	56.9
Total deferred charges and other assets	**338.7**	461.7
TOTAL ASSETS	**$ 10,412.7**	$ 9,939.6

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(In millions)*	2017	2016
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 168.4**	$ 236.2
Accounts payable	**230.4**	205.4
Dividends payable	**66.4**	60.4
Customer deposits	**80.7**	77.7
Accrued taxes	**44.5**	41.3
Accrued interest	**44.0**	40.4
Accrued compensation	**35.9**	45.1
Long-term debt due within one year	**249.8**	224.7
Fuel clause over recoveries	**1.7**	—
Other	**28.7**	96.0
Total current liabilities	**950.5**	1,027.2
LONG-TERM DEBT	**2,749.6**	2,405.8
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	**192.7**	274.8
Deferred income taxes	**1,227.8**	2,334.5
Regulatory liabilities	**1,283.4**	299.7
Other	**157.6**	153.8
Total deferred credits and other liabilities	**2,861.5**	3,062.8
Total liabilities	**6,561.6**	6,495.8
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**1,114.8**	1,105.8
Retained earnings	**2,759.5**	2,367.3
Accumulated other comprehensive loss, net of tax	**(23.2)**	(29.3)
Total stockholders' equity	**3,851.1**	3,443.8
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 10,412.7**	$ 9,939.6

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*		**2017**	2016
STOCKHOLDERS' EQUITY			
Common stock, par value $0.01 per share; authorized 450.0 shares; and outstanding 199.7 shares and 199.7 shares, respectively		**$ 2.0**	$ 2.0
Premium on common stock		**1,112.8**	1,103.8
Retained earnings		**2,759.5**	2,367.3
Accumulated other comprehensive loss, net of tax		**(23.2)**	(29.3)
Total stockholders' equity		**3,851.1**	3,443.8
LONG-TERM DEBT			
SERIES	DUE DATE		
Senior Notes - OGE Energy			
1.87%	Variable Senior Notes, Series Due November 24, 2017	**—**	100.0
Senior Notes - OG&E			
6.50%	Senior Notes, Series Due July 15, 2017	**—**	125.0
6.35%	Senior Notes, Series Due September 1, 2018	**250.0**	250.0
8.25%	Senior Notes, Series Due January 15, 2019	**250.0**	250.0
6.65%	Senior Notes, Series Due July 15, 2027	**125.0**	125.0
6.50%	Senior Notes, Series Due April 15, 2028	**100.0**	100.0
5.75%	Senior Notes, Series Due January 15, 2036	**110.0**	110.0
6.45%	Senior Notes, Series Due February 1, 2038	**200.0**	200.0
5.85%	Senior Notes, Series Due June 1, 2040	**250.0**	250.0
5.25%	Senior Notes, Series Due May 15, 2041	**250.0**	250.0
3.90%	Senior Notes, Series Due May 1, 2043	**250.0**	250.0
4.55%	Senior Notes, Series Due March 15, 2044	**250.0**	250.0
4.00%	Senior Notes, Series Due December 15, 2044	**250.0**	250.0
4.15%	Senior Notes, Series Due April 1, 2047	**300.0**	—
3.85%	Senior Notes, Series Due August 15, 2047	**300.0**	—
3.70%	Tinker Debt, Due August 31, 2062	**9.7**	9.9
Other Bonds - OG&E			
0.65% - 1.86%	Garfield Industrial Authority, January 1, 2025	**47.0**	47.0
0.65% - 1.80%	Muskogee Industrial Authority, January 1, 2025	**32.4**	32.4
0.66% - 1.80%	Muskogee Industrial Authority, June 1, 2027	**56.0**	56.0
Unamortized debt expense		**(20.8)**	(15.5)
Unamortized discount		**(9.9)**	(9.3)
Total long-term debt		**2,999.4**	2,630.5
Less: long-term debt due within one year		**(249.8)**	(224.7)
Total long-term debt (excluding debt due within one year)		**2,749.6**	2,405.8
Total capitalization (including long-term debt due within one year)		**$ 6,850.5**	$ 6,074.3

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

(In millions)	Shares Outstanding	Common Stock	Premium on Common Stock	Retained Earnings	Accumulated Other Comprehensive (Loss) Income	Total
Balance at December 31, 2014	199.4	$ 2.0	$ 1,085.6	$ 2,198.2	$ (41.4)	$ 3,244.4
Net income	—	—	—	271.3	—	271.3
Other comprehensive income, net of tax	—	—	—	—	6.3	6.3
Dividends declared on common stock	—	—	—	(209.7)	—	(209.7)
Issuance of common stock	0.2	—	7.2	—	—	7.2
Stock-based compensation	0.1	—	6.5	—	—	6.5
Balance at December 31, 2015	199.7	$ 2.0	$ 1,099.3	$ 2,259.8	$ (35.1)	$ 3,326.0
Net income	—	—	—	338.2	—	338.2
Other comprehensive income, net of tax	—	—	—	—	5.8	5.8
Dividends declared on common stock	—	—	—	(230.7)	—	(230.7)
Stock-based compensation	—	—	4.5	—	—	4.5
Balance at December 31, 2016	199.7	$ 2.0	$ 1,103.8	$ 2,367.3	$ (29.3)	$ 3,443.8
Net income	**—**	**—**	**—**	**619.0**	**—**	**619.0**
Cumulative effect of change in accounting principles	**—**	**—**	**—**	**26.8**	**(4.5)**	**22.3**
Other comprehensive income, net of tax	**—**	**—**	**—**	**—**	**10.6**	**10.6**
Dividends declared on common stock	—	—	—	**(253.6)**	—	**(253.6)**
Expense of common stock	**—**	**—**	**(0.1)**	**—**	**—**	**(0.1)**
Stock-based compensation	—	—	**9.1**	—	—	**9.1**
Balance at December 31, 2017	**199.7**	**$ 2.0**	**$ 1,112.8**	**$ 2,759.5**	**$ (23.2)**	**$ 3,851.1**

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

1. Summary of Significant Accounting Policies

Organization

The Company is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central U.S. The Company conducts these activities through two business segments: (i) electric utility and (ii) natural gas midstream operations. The accounts of the Company and its wholly owned subsidiaries are included in the consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation. The Company generally uses the equity method of accounting for investments where its ownership interest is between 20 percent and 50 percent and it lacks the power to direct activities that most significantly impact economic performance.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E and are subject to regulation by the OCC, the APSC and the FERC. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory and is a wholly owned subsidiary of the Company. OG&E is the largest electric utility in Oklahoma, and its franchised service territory includes Fort Smith, Arkansas and the surrounding communities. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

The natural gas midstream operations segment represents the Company's investment in Enable through wholly owned subsidiaries and ultimately OGE Holdings. Enable is engaged in the business of gathering, processing, transporting and storing natural gas. Enable's natural gas gathering and processing assets are strategically located in four states and serve natural gas production from shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. Enable also owns an emerging crude oil gathering business in the Bakken Shale formation, principally located in the Williston Basin of North Dakota. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

Enable was formed effective May 1, 2013 by the Company, the ArcLight group and CenterPoint to own and operate the midstream businesses of the Company and CenterPoint. In the formation transaction, the Company and the ArcLight group contributed Enogex LLC to Enable, and the Company deconsolidated its previously held investment in Enogex Holdings and acquired an equity interest in Enable. The Company determined that its contribution of Enogex LLC to Enable met the requirements of being in substance real estate and was recorded at historical cost. The general partner of Enable is equally controlled by the Company and CenterPoint, who each have 50 percent management ownership. Based on the 50/50 management ownership, with neither company having control, the Company began accounting for its interest in Enable using the equity method of accounting.

The Company charges operating costs to OG&E and Enable based on several factors. Operating costs directly related to OG&E and Enable are assigned as such. Operating costs incurred for the benefit of OG&E and Enable are allocated either as overhead based primarily on labor costs or using the "Distrigas" method. The "Distrigas" method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. The Company adopted this method in January 1996 as a result of a recommendation by the OCC Staff. The Company believes this method provides a reasonable basis for allocating common expenses.

Accounting Records

The accounting records of OG&E are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the OCC and the APSC. Additionally, OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide that certain incurred costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

OG&E records certain incurred costs and obligations as regulatory assets or liabilities if, based on regulatory orders or other available evidence, it is probable that the costs or obligations will be included in amounts allowable for recovery or refund in future rates.

The following table is a summary of OG&E's regulatory assets and liabilities:

December 31 *(In millions)*	2017	2016
Regulatory Assets		
Current:		
Oklahoma demand program rider under recovery (A)	**$ 31.6**	$ 51.0
SPP cost tracker under recovery (A)	**7.7**	10.0
Fuel clause under recoveries	**—**	51.3
Other (A)	**1.5**	9.5
Total current regulatory assets	**$ 40.8**	$ 121.8
Non-current:		
Benefit obligations regulatory asset	**$ 177.2**	$ 232.6
Deferred storm expenses	**42.2**	35.7
Smart Grid	**32.8**	43.2
Unamortized loss on reacquired debt	**12.3**	13.4
Income taxes recoverable from customers, net	**—**	62.3
Other	**18.5**	17.6
Total non-current regulatory assets	**$ 283.0**	$ 404.8
Regulatory Liabilities		
Current:		
Fuel clause over recoveries	**$ 1.7**	$ —
Other (B)	**2.2**	12.3
Total current regulatory liabilities	**$ 3.9**	$ 12.3
Non-current:		
Income taxes refundable to customers, net	**$ 955.5**	$ —
Accrued removal obligations, net	**288.4**	262.8
Pension tracker	**32.3**	35.5
Other	**7.2**	1.4
Total non-current regulatory liabilities	**$ 1,283.4**	$ 299.7

(A) Included in Other Current Assets on the Consolidated Balance Sheets.
(B) Included in Other Current Liabilities on the Consolidated Balance Sheets.

OG&E recovers program costs related to the Demand and Energy Efficiency Program. An extension of the demand program rider was approved in January 2016, which allows for the recovery through December 2018 of (i) energy efficiency program costs, (ii) lost revenues associated with certain achieved energy efficiency and demand savings, (iii) performance-based incentives and (iv) costs associated with research and development investments.

OG&E recovers certain SPP costs related to base plan charges from its customers and refunds certain SPP revenues received to its customers in Oklahoma through the SPP cost tracker.

Fuel clause under recoveries are generated from under recoveries from OG&E's customers when OG&E's cost of fuel exceeds the amount billed to its customers. Fuel clause over recoveries are generated from over recoveries from OG&E's customers when the amount billed to its customers exceeds OG&E's cost of fuel. OG&E's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel costs in periods of rising fuel prices above the baseline charge for fuel and over recovers fuel costs when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under and over recovery balances.

The benefit obligations regulatory asset is comprised of expenses recorded which are probable of future recovery and that have not yet been recognized as components of net periodic benefit cost, including net loss and prior service cost. These expenses are recorded as a regulatory asset as OG&E had historically recovered and currently recovers pension and postretirement benefit plan expense in its electric rates. If, in the future, the regulatory bodies indicate a change in policy related to the recovery of pension and postretirement benefit plan expenses, this could cause the benefit obligations regulatory asset balance to be reclassified to accumulated other comprehensive income.

The following table is a summary of the components of the benefit obligations regulatory asset:

December 31 *(In millions)*	**2017**	2016
Pension Plan and Restoration of Retirement Income Plan:		
Net loss	**$ 172.4**	$ 199.9
Postretirement Benefit Plans:		
Net loss	**33.6**	32.7
Prior service cost	**(28.8)**	—
Total	**$ 177.2**	$ 232.6

The following amounts in the benefit obligations regulatory asset at December 31, 2017 are expected to be recognized as components of net periodic benefit cost in 2018:

(In millions)	
Pension Plan and Restoration of Retirement Income Plan:	
Net loss	**$ 12.5**
Postretirement Benefit Plans:	
Net loss	**4.0**
Prior service cost	**(6.1)**
Total	**$ 10.4**

OG&E includes in expense any Oklahoma storm-related operation and maintenance expenses up to $2.7 million annually and defers any additional expenses incurred over $2.7 million. OG&E expects to recover the amounts deferred each year over a five-year period in accordance with historical practice.

OG&E previously recovered the cost of system-wide deployment of smart grid technology and implementing the smart grid pilot program through a rider. Costs not included in the rider are the incremental costs for web portal access, education and home energy reports, which are capped at $6.9 million, and the stranded costs associated with OG&E's analog electric meters, which have been replaced by smart meters. These incremental and stranded costs were accumulated during the smart grid deployment and have been included in the Smart Grid asset in the regulatory assets and liabilities table above. As approved in the recent Oklahoma rate case effective May 1, 2017, these costs are now being recovered over a six year period.

Unamortized loss on reacquired debt is comprised of unamortized debt issuance costs related to the early retirement of OG&E's long-term debt. These amounts are recorded in interest expenses and are being amortized over the term of the long-term debt which replaced the previous long-term debt. The unamortized loss on reacquired debt is recovered as a part of OG&E's cost of capital.

Income taxes refundable to customers, net, represent the reduction in accumulated deferred income taxes resulting from the reduction in the federal income tax rate, as part of the 2017 Tax Act. These amounts will be returned to customers in varying amounts over approximately 80 years. Currently, those amounts are shown net of income taxes recoverable from customers, which represents income tax benefits previously used to reduce OG&E's revenues, are treated as regulatory assets and are being amortized over the estimated remaining life of the assets to which they relate. These amounts are being recovered in rates as the temporary differences that generated the income tax benefit turn around.

Accrued removal obligations, net represent asset retirement costs previously recovered from ratepayers for other than legal obligations.

OG&E recovers specific amounts of pension and postretirement medical costs in rates approved in its Oklahoma rate cases. In accordance with approved orders, OG&E defers the difference between actual pension and postretirement medical expenses and the amount approved in its last Oklahoma rate case as a regulatory asset or regulatory liability. These amounts have been recorded in the Pension tracker regulatory liability in the regulatory assets and liabilities table above.

Management continuously monitors the future recoverability of regulatory assets. When, in management's judgment, future recovery becomes impaired, the amount of the regulatory asset is adjusted, as appropriate. If OG&E were required to

discontinue the application of accounting principles for certain types of rate-regulated activities for some or all of its operations, it could result in writing off the related regulatory assets, which could have significant financial effects.

Use of Estimates

In preparing the Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's Consolidated Financial Statements. However, the Company believes it has taken reasonable positions where assumptions and estimates are used in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised includes the determination of Pension Plan assumptions, income taxes, contingency reserves, asset retirement obligations and depreciable lives of property, plant and equipment. For the electric utility segment, significant judgment is also exercised in the determination of regulatory assets and liabilities and unbilled revenues.

Cash and Cash Equivalents

For purposes of the Consolidated Financial Statements, the Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents. These investments are carried at cost, which approximates fair value.

Allowance for Uncollectible Accounts Receivable

Customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable for OG&E is calculated by multiplying the last six months of electric revenue by the provision rate, which is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. Also, a portion of the uncollectible provision related to fuel within the Oklahoma jurisdiction is being recovered through the fuel adjustment clause. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in the Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was $1.5 million at both December 31, 2017 and 2016.

New business customers are required to provide a security deposit in the form of cash, bond or irrevocable letter of credit that is refunded when the account is closed. New residential customers whose outside credit scores indicate an elevated risk are required to provide a security deposit that is refunded based on customer protection rules defined by the OCC and the APSC. The payment behavior of all existing customers is continuously monitored, and, if the payment behavior indicates sufficient risk within the meaning of the applicable utility regulation, customers will be required to provide a security deposit.

Fuel Inventories

Fuel inventories for the generation of electricity consist of coal, natural gas and oil. OG&E uses the weighted-average cost method of accounting for inventory that is physically added to or withdrawn from storage or stockpiles. The amount of fuel inventory was $84.3 million and $82.4 million at December 31, 2017 and 2016, respectively. Effective May 1, 2014, the gas storage services agreement with Enable was terminated. As a result of this contract termination, approximately 5.3 Bcf of cushion gas owned by OG&E and stored on the Enable system is being directed to OG&E's power plants over a five-year period during peak time of June 1 to August 31 at a rate of 11,500 MMBtu/day for a total of 1.06 Bcf per year. In 2014, approximately $11.0 million of cushion gas was reclassified from Plant-in-Service to Other Deferred Assets, representing natural gas in storage that will be removed from storage over four years. As of December 31, 2017, the remaining balance of cushion gas of $2.8 million is included in Fuel Inventories.

Property, Plant and Equipment

All property, plant and equipment is recorded at cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and the allowance for funds used during construction. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances, and the cost of such property is charged to Accumulated Depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation, and the remaining balance net of any salvage proceeds is recorded as a loss in the Consolidated Statements of Income

as Other Expense. Repair and replacement of minor items of property are included in the Consolidated Statements of Income as Other Operation and Maintenance Expense.

The tables below present OG&E's ownership interest in the jointly-owned McClain Plant and the jointly-owned Redbud Plant, and, as disclosed below, only OG&E's ownership interest is reflected in the property, plant and equipment and accumulated depreciation balances in these tables. The owners of the remaining interests in the McClain Plant and the Redbud Plant are responsible for providing their own financing of capital expenditures. Also, only OG&E's proportionate interests of any direct expenses of the McClain Plant and the Redbud Plant, such as fuel, maintenance expense and other operating expenses, are included in the applicable financial statement captions in the Consolidated Statements of Income.

December 31, 2017 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
McClain Plant (A)	**77%**	**$ 226.8**	**$ 71.4**	**$ 155.4**
Redbud Plant (A)(B)	**51%**	**$ 496.6**	**$ 136.0**	**$ 360.6**

(A) Construction work in progress was $0.4 million and $7.8 million for the McClain and Redbud Plants, respectively.
(B) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $50.8 million.

December 31, 2016 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
McClain Plant (A)	77%	$ 234.2	$ 72.3	$ 161.9
Redbud Plant (A)(B)	51%	$ 489.0	$ 121.0	$ 368.0

(A) Construction work in progress was $0.2 million and $1.8 million for the McClain and Redbud Plants, respectively.
(B) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $45.3 million.

The Company's property, plant and equipment and related accumulated depreciation are divided into the following major classes:

December 31, 2017 *(In millions)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company):			
Property, plant and equipment	**$ 6.1**	**$ —**	**$ 6.1**
OGE Energy property, plant and equipment	**6.1**	**—**	**6.1**
OG&E:			
Distribution assets	**4,057.1**	**1,259.1**	**2,798.0**
Electric generation assets (A)	**4,475.0**	**1,493.5**	**2,981.5**
Transmission assets (B)	**2,767.7**	**506.5**	**2,261.2**
Intangible plant	**181.8**	**135.8**	**46.0**
Other property and equipment	**421.0**	**173.9**	**247.1**
OG&E property, plant and equipment	**11,902.6**	**3,568.8**	**8,333.8**
Total property, plant and equipment	**$ 11,908.7**	**$ 3,568.8**	**$ 8,339.9**

(A) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $50.8 million.
(B) This amount includes a plant acquisition adjustment of $3.3 million and accumulated amortization of $0.6 million.

December 31, 2016 *(In millions)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company):			
Property, plant and equipment	$ 117.7	$ 103.3	$ 14.4
OGE Energy property, plant and equipment	117.7	103.3	14.4
OG&E:			
Distribution assets	3,896.2	1,221.5	2,674.7
Electric generation assets (A)	4,155.9	1,493.3	2,662.6
Transmission assets (B)	2,548.8	481.3	2,067.5
Intangible plant	85.0	43.9	41.1
Other property and equipment	381.5	145.6	235.9
OG&E property, plant and equipment	11,067.4	3,385.6	7,681.8
Total property, plant and equipment	$ 11,185.1	$ 3,488.9	$ 7,696.2

(A) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $45.3 million.
(B) This amount includes a plant acquisition adjustment of $3.3 million and accumulated amortization of $0.6 million.

The following table summarizes the Company's unamortized computer software costs included in intangible plant above.

December 31 *(In millions)*	**2017**	2016
OGE Energy (holding company)	**$ —**	$ 1.0
OG&E	**37.5**	36.5
Total	**$ 37.5**	$ 37.5

The following table summarizes the Company's amortization expense for computer software costs.

Year Ended December 31 *(In millions)*	**2017**	2016	2015
OGE Energy (holding company)	**$ 0.2**	$ 1.4	$ 2.0
OG&E	**8.8**	8.0	6.9
Total	**$ 9.0**	$ 9.4	$ 8.9

Depreciation and Amortization

The provision for depreciation, which was 2.5 percent and 3.0 percent of the average depreciable utility plant for 2017 and 2016, respectively, is calculated using the straight-line method over the estimated service life of the utility assets. Depreciation is provided at the unit level for production plant and at the account or sub-account level for all other plant and is based on the average life group method. In 2018, the provision for depreciation is projected to be 2.7 percent of the average depreciable utility plant.

Amortization of intangible assets is calculated using the straight-line method. Of the remaining amortizable intangible plant balance at December 31, 2017, 98.6 percent will be amortized over 10.4 years with the remaining 1.4 percent of the intangible plant balance at December 31, 2017 being amortized over 23.7 years.

Amortization of plant acquisition adjustments is provided on a straight-line basis over the estimated remaining service life of the acquired asset. Plant acquisition adjustments include $148.3 million for the Redbud Plant, which is being amortized over a 27 year life and $3.3 million for certain transmission substation facilities in OG&E's service territory, which are being amortized over a 37 to 59 year period.

Investment in Unconsolidated Affiliate

The Company's investment in Enable is considered to be a variable interest entity because the owners of the equity at risk in this entity have disproportionate voting rights in relation to their obligations to absorb the entity's expected losses or to receive its expected residual returns. However, the Company is not considered the primary beneficiary of Enable since it does

not have the power to direct the activities that are considered most significant to the economic performance of Enable. The Company accounts for its investment in Enable using the equity method of accounting. Under the equity method, the investment will be adjusted each period for contributions made, distributions received and the Company's share of the investee's comprehensive income as adjusted for basis differences. The Company's maximum exposure to loss related to Enable is limited to the Company's equity investment in Enable at December 31, 2017 as presented in Note 12. The Company evaluates its equity method investments for impairment when events or changes in circumstances indicate there is a loss in value of the investment that is other than a temporary decline.

The Company considers distributions received from Enable which do not exceed cumulative equity in earnings subsequent to the date of investment to be a return on investment and are classified as operating activities in the Consolidated Statements of Cash Flows. The Company considers distributions received from Enable in excess of cumulative equity in earnings subsequent to the date of investment to be a return of investment and are classified as investing activities in the Consolidated Statements of Cash Flows.

Asset Retirement Obligations

OG&E has asset retirement obligations primarily associated with the removal of company-owned wind turbines on leased land, as well as the removal of asbestos from certain power generating stations.

The Company has recorded asset retirement obligations that are being accreted over their respective lives ranging from three to 74 years.

The following table summarizes changes to the Company's asset retirement obligations during the years ended December 31, 2017 and 2016.

(In millions)	**2017**	2016
Balance at January 1	**$ 69.6**	$ 63.3
Accretion expense	**3.1**	2.8
Revisions in estimated cash flows (A)	**2.4**	3.6
Liabilities settled	**—**	(0.1)
Balance at December 31	**$ 75.1**	$ 69.6

(A) Assumptions changed related to the estimated timing of asbestos abatement and estimated cost of ash pond removal at two of OG&E's generating facilities.

Allowance for Funds Used During Construction

Allowance for funds used during construction, a non-cash item, is reflected as an increase to net Other Income and a reduction to Interest Expense in the Consolidated Statements of Income and as an increase to Construction Work in Progress in the Consolidated Balance Sheets. Allowance for funds used during construction is calculated according to the FERC requirements for the imputed cost of equity and borrowed funds. Allowance for funds used during construction rates, compounded semi-annually, were 8.2 percent, 8.2 percent and 8.1 percent for the years ended December 31, 2017, 2016 and 2015, respectively.

Collection of Sales Tax

In the normal course of its operations, OG&E collects sales tax from its customers. OG&E records a current liability for sales taxes when it bills its customers and eliminates this liability when the taxes are remitted to the appropriate governmental authorities. OG&E excludes the sales tax collected from its operating revenues.

Revenue Recognition

General

OG&E recognizes revenue from electric sales when power is delivered to customers. OG&E reads its customers' meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. OG&E accrues an estimate of the revenues for electric sales delivered since the latest billings. Unbilled revenue is presented in Accrued Unbilled Revenues on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income based on estimates of usage and prices during the period. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

SPP Purchases and Sales

OG&E currently owns and operates transmission and generation facilities as part of a vertically integrated utility. OG&E is a member of the SPP regional transmission organization and has transferred operational authority, but not ownership, of OG&E's transmission facilities to the SPP. The SPP has implemented FERC-approved regional day-ahead and real-time markets for energy and operating services, as well as associated transmission congestion rights. Collectively, the three markets operate together under the global name, SPP Integrated Marketplace. OG&E represents owned- and contracted-generation assets and customer load in the SPP Integrated Marketplace for the sole benefit of its customers. OG&E has not participated in the SPP Integrated Marketplace for any speculative trading activities. OG&E records the SPP Integrated Marketplace transactions as sales or purchases per FERC Order 668, which requires that purchases and sales be recorded on a net basis for each settlement period of the SPP Integrated Marketplace. These results are reported as Operating Revenues or Cost of Sales in the Consolidated Financial Statements. OG&E revenues, expenses, assets and liabilities may be adversely affected by changes in the organization, operating and regulation by the FERC or the SPP.

Fuel Adjustment Clauses

The actual cost of fuel used in electric generation and certain purchased power costs are passed through to OG&E's customers through fuel adjustment clauses. The fuel adjustment clauses are subject to periodic review by the OCC and the APSC.

Income Taxes

The Company files consolidated income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Federal investment tax credits previously claimed on electric utility property have been deferred and are being amortized to income over the life of the related property. The Company uses the asset and liability method of accounting for income taxes. Under this method, a deferred tax asset or liability is recognized for the estimated future tax effects attributable to temporary differences between the financial statement basis and the tax basis of assets and liabilities as well as tax credit carry forwards and net operating loss carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period of the change. The Company recognizes interest related to unrecognized tax benefits in Interest Expense and recognizes penalties in Other Expense in the Consolidated Statements of Income.

On December 22, 2017, President Trump signed the 2017 Tax Act into law, significantly changing U.S. corporate income tax laws. The 2017 Tax Act reduces the corporate federal tax rate from 35 percent to 21 percent for tax years beginning after December 31, 2017. See Note 7 for further discussion of the effects of the 2017 Tax Act.

Accrued Vacation

The Company accrues vacation pay monthly by establishing a liability for vacation earned. Vacation may be taken as earned and is charged against the liability. At the end of each year, the liability represents the amount of vacation earned but not taken.

Accumulated Other Comprehensive Income (Loss)

The following tables summarize changes in the components of accumulated other comprehensive loss attributable to OGE Energy during 2016 and 2017. All amounts below are presented net of tax.

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans		
(In millions)	Net income (loss)	Prior service cost	Net income (loss)	Prior service cost	Total
Balance at December 31, 2015	$ (39.2)	$ 0.1	$ 2.5	$ 1.5	$ (35.1)
Other comprehensive income (loss) before reclassifications	(0.7)	—	0.2	—	(0.5)
Amounts reclassified from accumulated other comprehensive income (loss)	2.8	—	—	(1.5)	1.3
Settlement cost	5.0	—	—	—	5.0
Net current period other comprehensive income (loss)	7.1	—	0.2	(1.5)	5.8
Balance at December 31, 2016	(32.1)	0.1	2.7	—	(29.3)
Other comprehensive income (loss) before reclassifications	**0.4**	**—**	**(0.6)**	**6.3**	**6.1**
Amounts reclassified from accumulated other comprehensive income (loss)	**2.5**	**(0.1)**	**—**	**(0.6)**	**1.8**
Cumulative effect of change in accounting principle	**(5.7)**	**—**	**(0.1)**	**1.3**	**(4.5)**
Settlement cost	**2.2**	**—**	**0.5**	**—**	**2.7**
Net current period other comprehensive income (loss)	**(0.6)**	**(0.1)**	**(0.2)**	**7.0**	**6.1**
Balance at December 31, 2017	**$ (32.7)**	**$ —**	**$ 2.5**	**$ 7.0**	**$ (23.2)**

The following table summarizes significant amounts reclassified out of accumulated other comprehensive loss by the respective line items in net income during the years ended December 31, 2017 and 2016.

Details about Accumulated Other Comprehensive Income (Loss) Components	Amount Reclassified from Accumulated Other Comprehensive Income (Loss)		Affected Line Item in the Consolidated Statements of Comprehensive Income
	Year Ended December 31,		
(In millions)	**2017**	2016	
Amortization of Pension Plan and Restoration of Retirement Income Plan items:			
Actuarial losses (A)	**$ (3.9)**	$ (4.5)	Other Operation and Maintenance Expense
Prior service cost	**0.1**	—	Other Operation and Maintenance Expense
Settlement (A)	**(3.6)**	(8.2)	Other Operation and Maintenance Expense
	(7.4)	(12.7)	Income Before Taxes
	(2.8)	(4.9)	Income Tax (Benefit) Expense
	$ (4.6)	$ (7.8)	Net Income
Amortization of postretirement benefit plan items:			
Prior service cost	**$ 0.9**	$ 2.5	Other Operation and Maintenance Expense
Settlement (A)	**(0.7)**	—	Other Operation and Maintenance Expense
	0.2	2.5	Income Before Taxes
	0.1	1.0	Income Tax (Benefit) Expense
	$ 0.1	$ 1.5	Net Income
Total reclassifications for the period	**$ (4.5)**	$ (6.3)	Net Income

(A) These accumulated other comprehensive loss components are included in the computation of net periodic benefit cost (see Note 11 for additional information).

The amounts in accumulated other comprehensive loss (gain) at December 31, 2017 that are expected to be recognized into earnings in 2018 are as follows:

(In millions)	
Pension Plan and Restoration of Retirement Income Plan:	
Net loss	**$ (3.7)**
Prior service cost	**(0.1)**
Postretirement Benefit Plans:	
Prior service cost	**2.3**
Total, net of tax	**$ (1.5)**

Environmental Costs

Accruals for environmental costs are recognized when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Costs are charged to expense or deferred as a regulatory asset based on expected recovery from customers in future rates, if they relate to the remediation of conditions caused by past operations or if they are not expected to mitigate or prevent contamination from future operations. Where environmental expenditures relate to facilities currently in use, such as pollution control equipment, the costs may be capitalized and depreciated over the future service periods. Estimated remediation costs are recorded at undiscounted amounts, independent of any insurance or rate recovery, based on prior experience, assessments and current technology. Accrued obligations are regularly adjusted as environmental assessments and estimates are revised and remediation efforts proceed. For sites where OG&E has been designated as one of several potentially responsible parties, the amount accrued represents OG&E's estimated share of the cost. The Company had $17.1 million and $13.9 million in accrued environmental liabilities at December 31, 2017 and 2016, respectively, which are included in the Company's asset retirement obligations.

2. Accounting Pronouncements

Revenue from Contracts with Customers. In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)." The new revenue standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 2017. The Company has assessed the effect of this new guidance on its tariff-based sales, bundled arrangements and alternative revenue programs and is not aware of any issues that would have a material impact on the timing of revenue recognition. The new standard will not have a material impact on the Company's results of operations and financial position but will change the income statement presentation of revenues and require new disclosures. The Company adopted the new standard beginning in the first quarter of 2018 utilizing the modified retrospective transition method.

Leases. In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)." The main difference between current lease accounting and Topic 842 is the recognition of right-of-use assets and lease liabilities by lessees for those leases classified as operating leases under current accounting guidance. Lessees, such as the Company, will need to recognize a right-of-use asset and a lease liability for virtually all of their leases, other than leases that meet the definition of a short-term lease. The liability will be equal to the present value of lease payments. The asset will be based on the liability, subject to adjustment, such as for initial direct costs. For income statement purposes, Topic 842 retains a dual model, requiring leases to be classified as either operating or finance. Operating leases will result in straight-line expense, while finance leases will result in a front-loaded expense pattern, similar to current capital leases. Classification of operating and finance leases will be based on criteria that are largely similar to those applied in current lease guidance but without the explicit thresholds. The new guidance is effective for fiscal years beginning after December 2018. The new guidance must be adopted using a modified retrospective transition method and provides for certain practical expedients. Transition will require application of the new guidance at the beginning of the earliest comparative period presented. The Company has started evaluating its current lease contracts. The Company has not quantified the impact on its Consolidated Financial Statements, but it anticipates an increase in the recognition of right-of-use assets and lease liabilities.

In January 2018, the FASB issued ASU 2018-01, "Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842," which is an amendment to ASU 2016-02. Land easements (also commonly referred to as rights of way) represent the right to use, access or cross another entity's land for a specified purpose. This new guidance permits an entity to elect a transitional practical expedient, to be applied consistently, to not evaluate under Topic 842 land easements that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under ASC 840, "Leases." Once Topic 842 is adopted, an entity is required to apply Topic 842 prospectively to all new (or modified) land easements to determine whether the arrangement should be accounted for as a lease. ASU 2018-01 is effective for fiscal years beginning after December 2018. The Company intends to elect this practical expedient during its adoption of Topic 842.

Employee Share-based Payment Accounting. In March 2016, the FASB issued ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting," which amends ASC Topic 718, "Compensation - Stock Compensation." ASU 2016-09 includes provisions intended to simplify various aspects related to how share-based payments are accounted for and presented in the financial statements. The Company adopted this standard in the first quarter of 2017.

The new guidance, among other requirements, requires the following.

- All of the tax effects related to share-based payments at settlement (or expiration) should be recorded through the income statement. Previously, tax benefits in excess of compensation cost, or windfalls, were recorded in equity, and tax deficiencies, or shortfalls, were recorded in equity to the extent of previous windfalls and then to the income statement. Under the new guidance, the windfall tax benefit is recorded when it arises, subject to normal valuation allowance considerations. This change is required to be applied on a modified retrospective basis, with a cumulative effect adjustment

to opening retained earnings. Excess tax benefits are to be reported as operating activities on the statement of cash flows, which is a change from the previous requirement to present windfall tax benefits as an inflow from financing activities and an outflow from operating activities. As a result of adopting ASU 2016-09, the Company recorded a cumulative effect of $22.3 million as a deferred tax asset with an offset in retained earnings in the Consolidated Balance Sheets. Going forward, tax benefits in excess of compensation cost previously recorded in equity will be recorded within the income statement, and the related cash impact will be recorded as an operating activity within the statement of cash flows.

- Employee taxes paid when an employer withholds shares for tax-withholding purposes should be classified as a financing activity in the statement of cash flows, and this change should be applied retrospectively. As a result of the adoption, the Company reclassified shares withheld for employee taxes of $0.1 million and $1.7 million in 2016 and 2015, respectively, from operating activities to financing activities in the Consolidated Statements of Cash Flows. Going forward, shares withheld for employee taxes will be classified as a financing activity within the statement of cash flows.

- A policy election between recognizing forfeited awards as they occur or estimating the number of awards expected to be forfeited should be made and disclosed. The Company will continue to estimate forfeitures in accounting for stock-based compensation.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. In May 2017, the FASB issued ASU 2017-07, "Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost." The new guidance is designed to improve the reporting of pension and other postretirement benefit costs by bifurcating the components of net benefit expense between those that are attributed to compensation for service and those that are not. The service cost component of benefit expense will continue to be presented within operating income, but entities will now be required to present the other components of benefit expense as non-operating within the income statement. Additionally, the new guidance only permits the capitalization of the service cost component of net benefit expense. The accounting change is required to be applied on a retrospective basis for the presentation of components of net benefit cost and on a prospective basis for the capitalization of only the service cost component of net benefit costs. The new guidance is effective for annual periods beginning after December 2017, including interim periods within those annual periods. Early adoption is permitted, subject to certain conditions. The Company believes that the impact of the change in capitalization of only the service cost component of net periodic benefit costs will be immaterial from current practice. The Company adopted the new guidance beginning in the first quarter of 2018.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. In February 2018, the FASB issued ASU 2018-02, "Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income" that permits a reclassification from accumulated other comprehensive income to retained earnings of the stranded tax effects resulting from application of the new federal corporate income tax rate, resulting from the 2017 Tax Act. Prior to ASU 2018-02, GAAP required the remeasurement of deferred tax assets and liabilities as a result of a change in tax laws or rates to be presented in net income from continuing operations. Adjusting temporary differences originally recorded to accumulated other comprehensive income through continuing operations resulted in a disproportionate effect lodged in accumulated other comprehensive income. Under ASU 2018-02, entities are permitted, but not required, to reclassify from accumulated other comprehensive income to retained earnings those stranded tax effects resulting from the 2017 Tax Act. ASU 2018-02 is effective for all entities for fiscal years beginning after December 2018 and interim periods within those fiscal years. Early adoption is permitted. The amendments would be applied either at the beginning of the period of adoption or retrospectively to each period in which the effect of the change in the federal corporate income tax rate is recognized. The Company adopted the new standard for the year ended December 31, 2017. As a result of the adoption, the Company reclassified $4.5 million of deferred tax assets from accumulated other comprehensive income to retained earnings in the Consolidated Balance Sheets.

3. Investment in Unconsolidated Affiliate and Related Party Transactions

On March 14, 2013, the Company entered into a Master Formation Agreement with the ArcLight group and CenterPoint pursuant to which the Company, the ArcLight group and CenterPoint, agreed to form Enable to own and operate the midstream businesses of the Company and CenterPoint that was initially structured as a private limited partnership. This transaction closed on May 1, 2013.

Pursuant to the Master Formation Agreement, the Company and the ArcLight group indirectly contributed 100 percent of the equity interests in Enogex LLC to Enable. The Company determined that its contribution of Enogex LLC to Enable met the requirements of being in substance real estate and was recorded at historical cost.

The general partner of Enable is equally controlled by the Company and CenterPoint, who each have 50 percent management ownership. Based on the 50/50 management ownership, with neither company having control, the Company deconsolidated its interest in Enogex Holdings and began accounting for its interest in Enable using the equity method of accounting.

In April 2014, Enable completed an initial public offering of 25.0 million common units resulting in Enable becoming a publicly traded Master Limited Partnership. At December 31, 2017, the Company owned 111.0 million common units, or 25.7 percent, of Enable's outstanding common units. Prior to August 30, 2017, of the Company's 111.0 million common units, 68.2 million units were subordinated. The subordination period began on the closing date of Enable's initial public offering and extended until the first business day following the distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equal to or exceeding $1.15 per unit (the annualized minimum quarterly distribution) for each of the three consecutive, non-overlapping four-quarter periods immediately preceding June 30, 2017. On August 30, 2017, the first day following the payment of the cash distribution for common and subordinated units for the second quarter of 2017, the subordination period expired for the Company's 68.2 million subordinated units.

On February 9, 2018, Enable announced a quarterly dividend distribution of $0.31800 per unit on its outstanding common units, which is unchanged from the previous quarter. If cash distributions to Enable's unitholders exceed $0.330625 per unit in any quarter, the general partner will receive increasing percentages, up to 50 percent, of the cash Enable distributes in excess of that amount. The Company is entitled to 60 percent of those "incentive distributions." In certain circumstances, the general partner has the right to reset the minimum quarterly distribution and the target distribution levels at which the incentive distributions receive increasing percentages to higher levels based on Enable's cash distributions at the time of the exercise of this reset election.

Distributions received from Enable were $141.2 million, $141.2 million and $139.3 million during the years ended December 31, 2017, 2016 and 2015, respectively.

In 2016, CenterPoint Energy, Inc. announced that it was evaluating strategic alternatives for its investment in Enable. On July 18, 2016, CenterPoint Energy, Inc. and its wholly owned subsidiary, CenterPoint, provided notice to the Company of CenterPoint Energy Inc.'s solicitation of offers from unrelated third parties to acquire all or any portion of the common units and subordinated units of Enable owned by CenterPoint and all of the membership interests of the general partner of Enable owned by CenterPoint. This notice also constituted a notice pursuant to the right of first offer held by the Company under the Partnership Agreement and the Third Amended and Restated Limited Liability Company Agreement of the general partner. Under the terms of the right of first offer, the Company has 30 days from receipt of a notice from CenterPoint Energy Inc. to make an offer to buy all of CenterPoint's membership interests in the general partner and all or any portion of CenterPoint's common units and subordinated units. On August 17, 2016, the Company submitted to CenterPoint Energy Inc. a proposal to acquire, in conjunction with a third party, all of CenterPoint's membership interests in the general partner of Enable and all of the common units and subordinated units of Enable owned by CenterPoint. In accordance with the Enable partnership Agreement, CenterPoint Energy Inc. had 30 days after the proposal was submitted to accept the Company's right of first offer proposal. The Company did not receive a reply from CenterPoint Energy Inc. within the required timeframe.

On January 16, 2017, CenterPoint Energy, Inc. and its wholly owned subsidiary, CenterPoint, provided a second notice to the Company of CenterPoint Energy Inc.'s solicitation of offers from unrelated third parties to acquire all or any portion of the common units and subordinated units of Enable owned by CenterPoint and all of the membership interests of the general partner of Enable owned by CenterPoint Energy Inc. On February 15, 2017, under the terms of right of first offer, the Company submitted to CenterPoint Energy Inc. another proposal to acquire, in conjunction with a third party, all of CenterPoint's membership interests in the general partner of Enable and all of the common units and subordinated units of Enable owned by CenterPoint. The Company did not receive a reply from CenterPoint Energy Inc. within the required timeframe.

On July 15, 2017, CenterPoint Energy, Inc. and its wholly owned subsidiary, CenterPoint, provided a third notice to the Company of CenterPoint Energy Inc.'s solicitation of offers from unrelated third parties to acquire all or any portion of the common units and subordinated units of Enable owned by CenterPoint and all of the membership interests of the general partner of Enable owned by CenterPoint. On August 14, 2017, under the terms of right of first offer, the Company submitted to CenterPoint Energy Inc. another proposal to acquire, in conjunction with a third party, all of CenterPoint's membership interests in the general partner of Enable and all of the common units and subordinated units of Enable owned by CenterPoint.

On December 1, 2017, CenterPoint Energy, Inc. and its wholly owned subsidiary, CenterPoint, announced that late-stage discussions regarding a transaction involving CenterPoint's interest in Enable terminated because parties could not reach agreement on a mutually acceptable transaction.

The Company cannot predict what future actions CenterPoint will take, if any, associated with their ownership interest in Enable.

Related Party Transactions - the Company and Enable

Operating costs charged and related party transactions between the Company and its affiliate, Enable, are discussed below.

In connection with the formation of Enable, the Company and Enable entered into a Services Agreement, Employee Transition Agreement and other agreements whereby the Company agreed to provide certain support services to Enable such as accounting, legal, risk management and treasury functions for an initial term ending on April 30, 2016. As of December 31, 2015, Enable terminated all support services except certain information technology, payroll and benefits administration. The remaining services automatically extended for another year on May 1, 2017. Under these agreements, the Company charged operating costs to Enable of $2.3 million, $4.7 million and $12.4 million for December 31, 2017, 2016 and 2015, respectively. The Company charges operating costs to OG&E and Enable based on several factors. Operating costs directly related to OG&E and Enable are assigned as such. Operating costs incurred for the benefit of OG&E and Enable are allocated either as overhead based primarily on labor costs or using the "Distrigas" method.

The Company agreed to provide seconded employees to Enable to support its operations for an initial term ending on December 31, 2014. In October 2014, CenterPoint, the Company and Enable agreed to continue the secondment to Enable for 192 employees that participate in the Company's defined benefit and retirement plans. The Company billed Enable for reimbursement of $29.5 million, $28.7 million and $32.7 million in 2017, 2016 and 2015, respectively, under the Transitional Seconding Agreement for employment costs. If the seconding agreement was terminated, and those employees were no longer employed by the Company, and lump sum payments were made to those employees, the Company would recognize a settlement or curtailment of the pension/retiree health care charges, which would increase expense at the Company by approximately $14.6 million. Settlement and curtailment charges associated with the Enable seconded employees are not reimbursable to the Company by Enable. The seconding agreement can be terminated by mutual agreement of the Company and Enable or solely by the Company upon 120 day notice.

The Company had accounts receivable from Enable of $2.0 million and $2.7 million as of December 31, 2017 and 2016, respectively, for amounts billed for transitional services, including the cost of seconded employees.

Related Party Transactions - OG&E and Enable

OG&E entered into a contract with Enable to provide transportation services effective May 1, 2014. This transportation agreement grants Enable the responsibility of delivering natural gas to OG&E's generating facilities and performing an imbalance service. With this imbalance service, in accordance with the cash-out provision of the contract, OG&E purchases gas from Enable when Enable's deliveries exceed OG&E's pipeline receipts. Enable purchases gas from OG&E when OG&E's pipeline receipts exceed Enable's deliveries. In 2016, OG&E entered into an additional gas transportation services contract with Enable which will be effective upon the conversion of units 4 and 5 at Muskogee from coal to gas. The following table summarizes related party transactions between OG&E and Enable during the years ended December 31, 2017, 2016 and 2015.

	Year Ended December 31,		
(In millions)	**2017**	2016	2015
Operating revenues:			
Electricity to power electric compression assets	**$ 14.0**	$ 11.5	$ 13.8
Cost of sales:			
Natural gas transportation services	**$ 35.0**	$ 35.0	$ 35.0
Natural gas purchases (sales)	**(2.1)**	11.2	7.6

Summarized Financial Information of Enable

Summarized unaudited financial information for 100 percent of Enable is presented below as of December 31, 2017 and 2016 and for the years ended December 31, 2017, 2016 and 2015.

Balance Sheet	December 31,	
(In millions)	**2017**	2016
Current assets	**$ 416**	$ 396
Non-current assets	**11,177**	10,816
Current liabilities	**1,279**	362
Non-current liabilities	**2,660**	3,056

Income Statement	Year Ended December 31,		
(In millions)	**2017**	2016	2015
Operating revenues	**$ 2,803**	$ 2,272	$ 2,418
Cost of natural gas and NGLs	**1,381**	1,017	1,097
Operating income (loss)	**528**	385	(712)
Net income (loss)	**400**	290	(752)

The formation of Enable was considered a business combination, and CenterPoint was the acquirer of Enogex Holdings for accounting purposes. Under this method, the fair value of the consideration paid by CenterPoint for Enogex Holdings is allocated to the assets acquired and liabilities assumed on May 1, 2013 based on their fair value. Enogex Holdings' assets, liabilities and equity have accordingly been adjusted to estimated fair value as of May 1, 2013, resulting in an increase to Enable's equity of $2.2 billion. Due to the contribution of Enogex LLC to Enable meeting the requirements of being in substance real estate and thus recording the initial investment at historical cost, the effects of the amortization and depreciation expense associated with the fair value adjustments on Enable's results of operations have been eliminated in the Company's recording of its equity in earnings of Enable.

The Company recorded equity in earnings of unconsolidated affiliates of $131.2 million, $101.8 million and $15.5 million for the years ended December 31, 2017, 2016 and 2015, respectively. Equity in earnings of unconsolidated affiliates includes the Company's share of Enable earnings adjusted for the amortization of the basis difference of the Company's original investment in Enogex LLC and its underlying equity in the net assets of Enable and is also adjusted for the elimination of the Enogex Holdings fair value adjustments. The basis difference is being amortized over approximately 30 years, the average life of the assets to which the basis difference is attributed. Equity in earnings of unconsolidated affiliates is also adjusted for the elimination of the Enogex Holdings fair value adjustments, as described below.

The following table reconciles OGE Energy's equity in earnings of its unconsolidated affiliates for the years ended December 31, 2017 and 2016.

	Year Ended December 31,		
(In millions)	**2017**	2016	2015
Enable net income (loss)	**$ 400.3**	$ 289.5	$ (752.0)
Distributions senior to limited partners	**—**	(9.1)	—
Differences due to timing of OGE Energy and Enable accounting close	**—**	(12.2)	12.1
Enable net income (loss) used to calculate OGE Energy's equity in earnings	**$ 400.3**	$ 268.2	$ (739.9)
OGE Energy's percent ownership at period end	**25.7%**	25.7%	26.3%
OGE Energy's portion of Enable net income (loss)	**$ 102.7**	$ 70.7	$ (194.4)
Impairments recognized by Enable associated with OGE Energy's basis differences	**—**	2.6	178.4
OGE Energy's share of Enable net income (loss)	**102.7**	73.3	(16.0)
Amortization of basis difference	**11.3**	11.6	13.5
Elimination of Enable fair value step up	**17.2**	16.9	18.0
Equity in earnings of unconsolidated affiliates	**$ 131.2**	$ 101.8	$ 15.5

The difference between OGE Energy's investment in Enable and its underlying equity in the net assets of Enable was $714.2 million as of December 31, 2017. The basis difference is being amortized over approximately 30 years, beginning in May 2013. The following table reconciles the basis difference in Enable from December 31, 2016 to December 31, 2017.

(In millions)	
Basis difference as of December 31, 2016	$ 743.7
Change in Enable basis difference	(1.0)
Amortization of basis difference	(11.3)
Elimination of Enable fair value step up	(17.2)
Basis difference as of December 31, 2017	$ 714.2

2015 Goodwill Impairment. Enable tests its goodwill for impairment annually on October 1, or more frequently if events or changes in circumstances indicated that the carrying value of goodwill may not be recoverable. Beginning in the fourth quarter of 2014 and continuing into 2015, the crude oil and natural gas industry was impacted by significant commodity price declines, which resulted in decreased producer activity in certain regions in which Enable operates. Based on the decline in producer activity and the forecasted impact on future periods, in addition to an increase in the weighted average cost of capital, Enable determined that the impact on its forecasted operating profits and cash flows for its gathering and processing and transportation and storage segments for the next five years would be significantly reduced. As a result, when Enable performed its annual goodwill impairment analysis as of October 1, 2015, it determined that the goodwill for the gathering and processing and transportation and storage reporting units was completely impaired in the amount of $1.086 billion as of September 30, 2015 and wrote off all of its goodwill in the third quarter of 2015.

Accordingly, the Company recorded a $108.4 million pre-tax charge in the third quarter of 2015 for its share of the goodwill impairment, as adjusted for the basis differences.

4. Fair Value Measurements

The classification of the Company's fair value measurements requires judgment regarding the degree to which market data is observable or corroborated by observable market data. GAAP establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to quoted prices in active markets for identical unrestricted assets or liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The three levels defined in the fair value hierarchy are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible at the measurement date.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the reporting entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk).

The Company had no financial instruments measured at fair value on a recurring basis at December 31, 2017 and 2016. The fair value of the Company's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy with the exception of the Tinker Debt whose fair value is based on calculating the net present value of the monthly payments discounted by the Company's current borrowing rate and is classified as Level 3 in the fair value hierarchy. The following table summarizes the fair value and carrying amount of the Company's financial instruments at December 31, 2017 and 2016.

	2017		2016	
December 31 *(In millions)*	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-term Debt (including Long-term Debt due within one year):				
Senior Notes	**$ 2,854.3**	**$ 3,242.8**	$ 2,385.5	$ 2,657.2
OG&E Industrial Authority Bonds	**135.4**	**135.4**	135.4	135.4
Tinker Debt	**9.7**	**9.8**	9.9	11.3
OGE Energy Senior Notes	**—**	**—**	99.7	99.9

5. Stock-Based Compensation

In 2013, the Company adopted, and its shareholders approved, the Stock Incentive Plan. Under the Stock Incentive Plan, restricted stock, restricted stock units, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees of the Company and its subsidiaries. The Company has authorized the issuance of up to 7,400,000 shares under the Stock Incentive Plan.

The following table summarizes the Company's pre-tax compensation expense and related income tax benefit for the years ended December 31, 2017, 2016 and 2015 related to the Company's performance units and restricted stock.

Year Ended December 31 *(In millions)*	**2017**	2016	2015
Performance units:			
Total shareholder return	**$ 7.6**	$ 4.5	$ 7.6
Earnings per share	**1.4**	—	0.7
Total performance units	**9.0**	4.5	8.3
Restricted stock	**0.1**	0.1	0.1
Total compensation expense	**9.1**	4.6	8.4
Less: Amount paid by unconsolidated affiliates	**—**	—	0.5
Net compensation expense	**$ 9.1**	$ 4.6	$ 7.9
Income tax benefit	**$ 3.5**	$ 1.8	$ 3.1

The Company has issued new shares to satisfy restricted stock grants and payouts of earned performance units. In 2017, 2016 and 2015, there were 2,298 shares, 2,100 shares and 82,046 shares, respectively, of new common stock issued pursuant to the Company's Stock Incentive Plan related to restricted stock grants (net of forfeitures) and payouts of earned performance units. In 2017, there were 146 shares of restricted stock returned to the Company to satisfy tax liabilities.

Performance Units

Under the Stock Incentive Plan, the Company has issued performance units which represent the value of one share of the Company's common stock. The performance units provide for accelerated vesting if there is a change in control (as defined in the Stock Incentive Plan). Each performance unit is subject to forfeiture if the recipient terminates employment with the Company or a subsidiary prior to the end of the primarily three-year award cycle for any reason other than death, disability or retirement. In the event of death, disability or retirement, a participant will receive a prorated payment based on such participant's number of full months of service during the award cycle, further adjusted based on the achievement of the performance goals during the award cycle.

The performance units granted based on total shareholder return are contingently awarded and will be payable in shares of the Company's common stock subject to the condition that the number of performance units, if any, earned by the employees upon the expiration of a primarily three-year award cycle (i.e., three-year cliff vesting period) is dependent on the Company's total shareholder return ranking relative to a peer group of companies. The performance units granted based on earnings per share are contingently awarded and will be payable in shares of the Company's common stock based on the Company's earnings per share growth over a primarily three-year award cycle (i.e., three-year cliff vesting period) compared to a target set at the time of the grant by the Compensation Committee of the Company's Board of Directors. All of these performance units are classified as equity in the Consolidated Balance Sheets. If there is no or only a partial payout for the performance units at the end of the award cycle, the unearned performance units are cancelled. Payout requires approval of the Compensation Committee of the Company's Board of Directors. Payouts, if any, are all made in common stock and are considered made when the payout is approved by the Compensation Committee.

Performance Units – Total Shareholder Return

The fair value of the performance units based on total shareholder return was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected dividend yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the performance units is a fixed amount determined at the grant date fair value and is recognized over the primarily three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Dividends were not accrued or paid for awards prior to February 2014 and were therefore not included in the fair value calculation. Beginning with the February 2014 performance unit awards, dividends are accrued on a quarterly basis pending achievement of payout criteria and were therefore included in the fair value calculations. Expected price volatility is based on the historical volatility of the Company's common stock for the past three years and was simulated using the Geometric Brownian Motion process. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. The expected life of the units is based on the non-vested period since inception of the award cycle. There are no post-vesting restrictions related to the Company's performance units based on total shareholder return. The number of performance units granted based on total shareholder return and the assumptions used to calculate the grant date fair value of the performance units based on total shareholder return are shown in the following table.

	2017	2016	2015
Number of units granted	**260,570**	284,211	264,454
Fair value of units granted	**$ 41.77**	$ 20.97	$ 31.02
Expected dividend yield	**3.8%**	3.5%	2.6%
Expected price volatility	**19.9%**	19.8%	16.9%
Risk-free interest rate	**1.44%**	0.88%	0.91%
Expected life of units (in years)	**2.80**	2.84	2.85

Performance Units – Earnings Per Share

The fair value of the performance units based on earnings per share is based on grant date fair value which is equivalent to the price of one share of the Company's common stock on the date of grant. The fair value of performance units based on earnings per share varies as the number of performance units that will vest is based on the grant date fair value of the units and the probable outcome of the performance condition. The Company reassesses at each reporting date whether achievement of the performance condition is probable and accrues compensation expense if and when achievement of the performance condition is probable. As a result, the compensation expense recognized for these performance units can vary from period to period. There are no post-vesting restrictions related to the Company's performance units based on earnings per share. The number of performance units granted based on earnings per share and the grant date fair value are shown in the following table.

	2017	2016	2015
Number of units granted	**86,857**	94,735	88,156
Fair value of units granted	**$ 34.83**	$ 26.64	$ 33.99

Restricted Stock

Under the Stock Incentive Plan, the Company issued restricted stock to certain existing non-officer employees as well as other executives upon hire to attract and retain individuals to be competitive in the marketplace. The restricted stock vests in one-third annual increments. Prior to vesting, each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement. These shares may not be sold, assigned, transferred or pledged and are subject to a risk of forfeiture.

The fair value of the restricted stock was based on the closing market price of the Company's common stock on the grant date. Compensation expense for the restricted stock is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a primarily three-year vesting period. Also, the Company treats its restricted stock as multiple separate awards by recording compensation expense separately for each tranche whereby a substantial portion of the expense is recognized in the earlier years in the requisite service period. Dividends are accrued and paid during the vesting period on restricted stock granted prior to July 2014; therefore, dividends are included in the fair value calculation for such restricted stock granted prior to July 2014.

For restricted stock granted after July 2014, dividends will only be paid on restricted stock awards that vest. Accordingly, for restricted stock granted after July 2014, only the present value of dividends expected to vest are included in the fair value calculations. The expected life of the restricted stock is based on the non-vested period since inception of the primarily three-year award cycle. There are no post-vesting restrictions related to the Company's restricted stock. The number of shares of restricted stock granted and the grant date fair value are shown in the following table.

	2017	2016	2015
Shares of restricted stock granted	**3,145**	1,881	958
Fair value of restricted stock granted	**$ 34.96**	$ 29.27	$ 26.11

A summary of the activity for the Company's performance units and restricted stock at December 31, 2017 and changes in 2017 are shown in the following table.

	Performance Units					
	Total Shareholder Return		Earnings Per Share		Restricted Stock	
(Dollars in millions)	Number of Units	Aggregate Intrinsic Value	Number of Units	Aggregate Intrinsic Value	Number of Shares	Aggregate Intrinsic Value
Units/shares outstanding at 12/31/16	664,045		221,350		4,912	
Granted	**260,570 (A)**		**86,857 (A)**		**3,145**	
Converted	**(185,214) (B)**	**$ —**	**(61,742) (B)**	**$ —**	**N/A**	
Vested	**N/A**		**N/A**		**(3,815)**	**$ 0.1**
Forfeited	**(14,850)**		**(4,947)**		**—**	
Units/shares outstanding at 12/31/17	**724,551**	**$ 2.4**	**241,518**	**$ 7.2**	**4,242**	**$ 0.1**
Units/shares fully vested at 12/31/17	**201,431**	**$ —**	**67,148**	**$ 1.2**		

(A) For performance units, this represents the target number of performance units granted. Actual number of performance units earned, if any, is dependent upon performance and may range from zero percent to 200 percent of the target.
(B) These amounts represent performance units that vested at December 31, 2016 which were settled in February 2017.

A summary of the activity for the Company's non-vested performance units and restricted stock at December 31, 2017 and changes in 2017 are shown in the following table.

	Performance Units					
	Total Shareholder Return		Earnings Per Share		Restricted Stock	
	Number of Units	Weighted-Average Grant Date Fair Value	Number of Units	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Units/shares non-vested at 12/31/16	478,831	$ 25.16	159,608	$ 29.71	4,912	$ 31.29
Granted	**260,570 (A)**	**$ 41.77**	**86,857 (A)**	**$ 34.83**	**3,145**	**$ 34.96**
Vested	**(201,431)**	**$ 31.18**	**(67,148)**	**$ 33.99**	**(3,815)**	**$ 31.71**
Forfeited	**(14,850)**	**$ 31.01**	**(4,947)**	**$ 31.12**	**—**	**$ —**
Units/shares non-vested at 12/31/17	**523,120**	**$ 30.96**	**174,370**	**$ 30.58**	**4,242**	**$ 33.58**
Units/shares expected to vest	**492,446 (B)**		**164,148 (B)**		**4,242**	

(A) For performance units, this represents the target number of performance units granted. Actual number of performance units earned, if any, is dependent upon performance and may range from zero percent to 200 percent of the target.
(B) The intrinsic value of the performance units based on total shareholder return and earnings per share is $2.3 million and $5.7 million, respectively.

Fair Value of Vested Performance Units and Restricted Stock

A summary of the Company's fair value for its vested performance units and restricted stock is shown in the following table.

Year Ended December 31 *(In millions)*	**2017**	2016	2015
Performance units:			
Total shareholder return	**$ 6.3**	$ 6.4	$ 8.5
Earnings per share	**1.2**	—	—
Restricted stock	**0.1**	0.1	0.2

Unrecognized Compensation Cost

A summary of the Company's unrecognized compensation cost for its non-vested performance units and restricted stock and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table.

December 31, 2017	Unrecognized Compensation Cost *(In millions)*	Weighted Average to be Recognized *(In years)*
Performance units:		
Total shareholder return	**$ 8.5**	**1.75**
Earnings per share	**2.6**	**1.67**
Total performance units	**11.1**	
Restricted stock	**0.1**	**1.34**
Total	**$ 11.2**	

6. Supplemental Cash Flow Information

The following table discloses information about investing and financing activities that affected recognized assets and liabilities but did not result in cash receipts or payments. Cash paid for interest, net of interest capitalized, and cash paid for income taxes, net of income tax refunds are also disclosed in the table.

Year Ended December 31 *(In millions)*	**2017**	2016	2015
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Power plant long-term service agreement	**$ 2.6**	$ 39.5	$ 2.3
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash paid during the period for:			
Interest (net of interest capitalized) (A)	**$ 139.6**	$ 141.9	$ 145.4
Income taxes (net of income tax refunds)	**(16.0)**	(5.9)	(3.4)

(A) Net of interest capitalized of $18.0 million, $7.5 million and $4.2 million in 2017, 2016 and 2015, respectively.

7. Income Taxes

2017 Tax Act

On December 22, 2017, President Trump signed the 2017 Tax Act into law, significantly changing U.S. corporate income tax laws. The 2017 Tax Act reduces the corporate federal tax rate from 35 percent to 21 percent for tax years beginning after December 31, 2017.

Among other things, the 2017 Tax Act repeals the alternative minimum tax regime for tax years beginning after December 31, 2017. For tax years beginning in 2018, 2019 and 2020, the alternative minimum tax credit carryforward can be utilized to offset regular tax with any remaining alternative minimum tax carryforwards eligible for a refund of 50 percent. Any remaining alternative minimum tax credit carryforwards will become fully refundable beginning in the 2021 tax year. The 2017 Tax Act also limits a taxpayer's ability to utilize net operating loss carryforwards to 80 percent of taxable income. Additionally, net operating losses arising after 2017 can be carried forward indefinitely, but carryback is generally prohibited. Net operating losses generated in tax years beginning before January 1, 2018 will not be subject to the taxable income limitation and will continue to have a two year carryback and 20 year carryforward period. The 2017 Tax Act allows companies to expense 100 percent of the cost of qualified property placed in service after September 27, 2017 and before January 1, 2023 (an additional year is provided for certain property with longer production periods). The 100 percent expense provision is phased down by 20 percent per calendar year beginning in 2023 (i.e., 80 percent, 60 percent, 40 percent and 20 percent for calendar years 2023 through 2026, respectively), with normal depreciation rules applicable after that. The phase out begins in 2024 for certain property with longer production periods. Companies can elect not to immediately expense qualified assets. The 2017 Tax Act limits deductions for net interest expense to 30 percent of adjusted taxable income. The 2017 Tax Act repeals deductions for qualified domestic production activities, entertainment, amusement or recreation expenses, membership dues for clubs and expenses incurred for the use of facilities in connection with these items. The 2017 Tax Act retains the $1 million limitation on deductible compensation to covered employees. However, it eliminates the current exception for performance-based compensation and expands the definition of covered employees

to include the chief financial officer. The new executive compensation limitations are effective in 2018, with certain transition rules.

During 2017, the Company fully utilized all remaining federal net operating losses and alternative minimum tax credits. Changes made by the 2017 Tax Act related to alternative minimum tax and net operating loss utilization are not expected to have a material impact on the Company in the future. For regulated entities, such as OG&E, provisions in the 2017 Tax Act provide for unrestricted deduction of interest expense in lieu of full expensing of qualified property. Full expensing of qualified property will be available with regard to the Company's non-regulated investments, and the Company currently does not believe the interest expense limitations on non-regulated debt will have a significant impact. The Company will see some impact from other provisions related to non-deductible expenses, but those items are not expected to be material with respect to 2018.

ASC 740, "Income Taxes," requires deferred tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. Therefore, at December 31, 2017, the Company remeasured deferred taxes based upon the new 21 percent tax rate. For entities subject to ASC 980, "Accounting for Regulated Entities," such as OG&E, those entities are required to recognize a regulatory liability for the decrease in taxes payable for the change in tax rates that are expected to be returned to customers through future rates and to recognize a regulatory asset for the increase in taxes receivable for the change in tax rates that are expected to be recovered from customers through future rates.

As a result of remeasuring existing deferred taxes at the lower 21 percent tax rate, the Company reduced net deferred income tax liabilities by $1.273 billion, reduced income tax expense by $234.7 million and increased regulatory liabilities, net by $1.038 billion.

Staff Accounting Bulletin No. 118

On December 22, 2017, the SEC staff issued Staff Accounting Bulletin No. 118 to address the application of U.S. GAAP in situations when a registrant does not have the necessary information available, prepared or analyzed (including computations) in reasonable detail to complete the accounting for certain income tax effects of the 2017 Tax Act. The Company has recognized the provisional tax impacts related to the revaluation of deferred tax assets and liabilities and included these amounts in its Consolidated Financial Statements for the year ended December 31, 2017. The ultimate impact may differ from these provisional amounts, possibly materially, due to, among other things, additional analysis, changes in interpretations and assumptions the Company has made, additional regulatory guidance that may be issued and actions the Company may take as a result of the 2017 Tax Act. Any subsequent adjustment to these amounts will be recorded to adjust the initial recognition of tax reform in the quarter of 2018 when the analysis is complete.

The items comprising income tax (benefit) expense are as follows:

Year Ended December 31 *(In millions)*	**2017**	2016	2015
Provision (benefit) for current income taxes:			
Federal	**$ 4.9**	$ —	$ —
State	**(4.2)**	(5.7)	(5.2)
Total provision (benefit) for current income taxes	**0.7**	(5.7)	(5.2)
(Benefit) provision for deferred income taxes, net:			
Federal	**(75.9)**	126.0	98.8
State	**26.0**	28.0	4.5
Total (benefit) provision for deferred income taxes, net	**(49.9)**	154.0	103.3
Deferred federal investment tax credits, net	**(0.1)**	(0.2)	(0.7)
Total income tax (benefit) expense	**$ (49.3)**	$ 148.1	$ 97.4

The Company files consolidated income tax returns in the U.S. federal jurisdiction and various state jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal tax examinations by tax authorities for years prior to 2014 or state and local tax examinations by tax authorities for years prior to 2013. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Federal investment tax credits previously claimed on electric utility property have been deferred and are being amortized to income over the life of the related property. OG&E earns both federal and Oklahoma state tax credits associated with production from its wind farms and earns Oklahoma state tax credits associated with its investments in electric generating facilities which reduce the Company's effective tax rate.

The following schedule reconciles the statutory tax rates to the effective income tax rate:

Year Ended December 31	**2017**	2016	2015
Statutory federal tax rate	**35.0 %**	35.0 %	35.0 %
Federal deferred tax revaluation	**(41.2)**	—	—
Federal renewable energy credit (A)	**(4.8)**	(6.8)	(8.9)
401(k) dividends	**(0.5)**	(0.6)	(0.7)
Federal investment tax credits, net	**(0.1)**	(0.8)	(0.2)
Other	**(0.1)**	0.1	0.3
State income taxes, net of federal income tax benefit	**2.0**	1.9	0.1
Amortization of net unfunded deferred taxes	**0.7**	0.7	0.9
Remeasurement of state deferred tax liabilities	**0.4**	0.9	(0.8)
Uncertain tax positions	**—**	0.1	0.7
Effective income tax rate	**(8.6)%**	30.5 %	26.4 %

(A) Represents credits associated with the production from OG&E's wind farms.

The deferred tax provisions are recognized as costs in the ratemaking process by the commissions having jurisdiction over the rates charged by OG&E. The components of Deferred Income Taxes at December 31, 2017 and 2016 were as follows:

December 31 *(In millions)*	**2017**	2016
Deferred income tax liabilities, net:		
Accelerated depreciation and other property related differences	**$ 1,449.6**	$ 2,103.2
Investment in Enable Midstream Partners	**441.7**	657.3
Regulatory asset	**18.9**	34.4
Company Pension Plan	**11.5**	16.5
Bond redemption-unamortized costs	**2.6**	4.3
Derivative instruments	**1.6**	2.2
Income taxes (recoverable from) refundable to customers, net	**(244.3)**	24.1
Federal tax credits	**(218.5)**	(220.6)
State tax credits	**(141.7)**	(112.2)
Postretirement medical and life insurance benefits	**(25.2)**	(48.9)
Net operating losses	**(21.1)**	(31.7)
Asset retirement obligations	**(19.2)**	(24.5)
Regulatory liabilities	**(16.8)**	(34.6)
Accrued liabilities	**(7.4)**	(16.1)
Accrued vacation	**(2.1)**	(3.5)
Other	**(0.9)**	(14.0)
Deferred federal investment tax credits	**(0.5)**	(0.8)
Uncollectible accounts	**(0.4)**	(0.6)
Total deferred income tax liabilities, net	**$ 1,227.8**	$ 2,334.5

As of December 31, 2017, the Company has classified $16.4 million of unrecognized tax benefits as a reduction of deferred tax assets recorded. Management is currently unaware of any issues under review that could result in significant additional payments, accruals or other material deviation from this amount.

Following is a reconciliation of the Company's total gross unrecognized tax benefits as of the years ended December 31, 2017, 2016 and 2015.

(In millions)	**2017**	2016	2015
Balance at January 1	**$ 20.7**	$ 20.2	$ 16.1
Tax positions related to current year:			
Additions	**—**	0.5	4.1
Balance at December 31	**$ 20.7**	$ 20.7	$ 20.2

As of December 31, 2017, 2016 and 2015, there were $16.4 million, $13.5 million and $13.2 million of unrecognized tax benefits that, if recognized, would affect the annual effective tax rate.

Where applicable, the Company classifies income tax-related interest and penalties as interest expense and other expense, respectively. During the year ended December 31, 2017, there were no income tax-related interest or penalties recorded with regard to uncertain tax positions.

The Company sustained federal and state tax operating losses through 2012 caused primarily by bonus depreciation and other book versus tax temporary differences. As a result, the Company had accrued federal and state income tax benefits carrying into 2017. During 2017, the remaining federal net operating loss was utilized. State operating losses are being carried forward for utilization in future years. In addition to the tax operating losses, the Company was unable to utilize the various tax credits that were generated during these years. These tax losses and credits are being carried as deferred tax assets and will be utilized in future periods. Under current law, the Company anticipates future taxable income will be sufficient to utilize remaining losses and credits before they begin to expire. The following table summarizes these carry forwards:

(In millions)	Carry Forward Amount	Deferred Tax Asset	Earliest Expiration Date
State operating loss	$ 472.1	$ 21.1	2030
Federal tax credits	218.5	218.5	2029
State tax credits:			
Oklahoma investment tax credits	144.1	113.8	N/A
Oklahoma capital investment board credits	8.5	8.5	N/A
Oklahoma zero emission tax credits	24.1	19.4	2020

8. Common Equity

Automatic Dividend Reinvestment and Stock Purchase Plan

The Company issued no shares of common stock under its Automatic Dividend Reinvestment and Stock Purchase Plan in 2017. The Company may, from time to time, issue shares under its Automatic Dividend Reinvestment and Stock Purchase Plan or purchase shares traded on the open market. At December 31, 2017, there were 4,774,442 shares of unissued common stock reserved for issuance under the Company's Automatic Dividend Reinvestment and Stock Purchase Plan.

Earnings Per Share

Basic earnings per share is calculated by dividing net income by the weighted average number of the Company's common shares outstanding during the period. In the calculation of diluted earnings per share, weighted average shares outstanding are increased for additional shares that would be outstanding if potentially dilutive securities were converted to common stock. Potentially dilutive securities for the Company consist of performance units and restricted stock. Basic and diluted earnings per share for the Company were calculated as follows:

(In millions except per share data)	**2017**	2016	2015
Net income	**$ 619.0**	$ 338.2	$ 271.3
Average common shares outstanding:			
Basic average common shares outstanding	**199.7**	199.7	199.6
Effect of dilutive securities:			
Contingently issuable shares (performance and restricted stock units)	**0.3**	0.2	—
Diluted average common shares outstanding	**200.0**	199.9	199.6
Basic earnings per average common share	**$ 3.10**	$ 1.69	$ 1.36
Diluted earnings per average common share	**$ 3.10**	$ 1.69	$ 1.36
Anti-dilutive shares excluded from earnings per share calculation	**—**	—	—

Dividend Restrictions

The Company's Certificate of Incorporation places restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. As there is no preferred stock outstanding, that restriction did not place any effective limit on the Company's ability to pay dividends to its shareholders. Pursuant to the leverage restriction in the Company's revolving credit agreement, the Company must maintain a percentage of debt to total capitalization at a level that does not exceed 65 percent. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization, which results in the restriction of approximately $605.3 million of the Company's retained earnings from being paid out in dividends. Accordingly, approximately $2.2 billion of the Company's retained earnings as of December 31, 2017 are unrestricted for the payment of dividends.

The Company utilizes receipts from its equity investment in Enable and dividends from OG&E to pay dividends to its shareholders. Enable's partnership agreement requires that it distribute all "available cash," as defined as cash on hand at the end of a quarter after the payment of expenses and the establishment of cash reserves and cash on hand resulting from working capital borrowings made after the end of the quarter. Pursuant to the Federal Power Act, OG&E is restricted from paying dividends from its capital accounts. Dividends are paid from retained earnings. Pursuant to the leverage restriction in OG&E's revolving credit agreement, OG&E must also maintain a percentage of debt to total capitalization at a level that does not exceed 65 percent. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization, which results in the restriction of approximately $600.1 million of OG&E's retained earnings from being paid out in dividends. Accordingly, approximately $1.8 billion of OG&E's retained earnings as of December 31, 2017 are unrestricted for the payment of dividends.

9. Long-Term Debt

A summary of the Company's long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2017, the Company was in compliance with all of its debt agreements.

OG&E Industrial Authority Bonds

OG&E has tax-exempt pollution control bonds with optional redemption provisions that allow the holders to request repayment of the bonds on any business day. The bonds, which can be tendered at the option of the holder during the next 12 months, are as follows:

SERIES	DATE DUE	AMOUNT
		(In millions)
0.65% - 1.86%	Garfield Industrial Authority, January 1, 2025	$ 47.0
0.65% - 1.80%	Muskogee Industrial Authority, January 1, 2025	32.4
0.66% - 1.80%	Muskogee Industrial Authority, June 1, 2027	56.0
Total (redeemable during next 12 months)		$ 135.4

All of these bonds are subject to an optional tender at the request of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to the date of purchase. The bond holders, on any business day, can request repayment of the bond by delivering an irrevocable notice to the tender agent stating the principal amount of the bond, payment instructions for the purchase price and the business day the bond is to be purchased. The repayment option may only be exercised by the holder of a bond for the principal amount. When a tender notice has been received by the trustee, a third party remarketing agent for the bonds will attempt to remarket any bonds tendered for purchase. This process occurs once per week. Since the original issuance of these series of bonds in 1995 and 1997, the remarketing agent has successfully remarketed all tendered bonds. If the remarketing agent is unable to remarket any such bonds, OG&E is obligated to repurchase such unremarketed bonds. As OG&E has both the intent and ability to refinance the bonds on a long-term basis and such ability is supported by an ability to consummate the refinancing, the bonds are classified as Long-Term Debt in the Company's Consolidated Financial Statements. OG&E believes that it has sufficient liquidity to meet these obligations.

Long-Term Debt Maturities

Maturities of the Company's long-term debt during the next five years consist of $250.1 million, $250.1 million, $0.1 million, $0.1 million and $0.1 million in 2018, 2019, 2020, 2021 and 2022, respectively.

The Company has previously incurred costs related to debt refinancing. Unamortized loss on reacquired debt is classified as a Non-Current Regulatory Asset. Unamortized debt expense and unamortized premium and discount on long-term debt are classified as Long-Term Debt in the Consolidated Balance Sheets and are being amortized over the life of the respective debt.

Issuance of Long-Term Debt

In March 2017, OG&E issued $300.0 million of 4.15 percent senior notes due April 1, 2047. The proceeds from the issuance were used for general corporate purposes, including to repay short-term debt, to repay borrowings under the revolving credit facility, to fund the payment of OG&E's $125.0 million of 6.5 percent senior notes that matured on July 15, 2017 and to fund ongoing capital expenditures and working capital.

In August 2017, OG&E issued $300.0 million of 3.85 percent senior notes due August 15, 2047. The proceeds from the issuance were used for general corporate purposes, including to repay short-term debt, to repay borrowings under the revolving credit facility and to fund ongoing capital expenditures and working capital.

10. Short-Term Debt and Credit Facilities

On March 8, 2017, the Company and OG&E each entered into new $450.0 million unsecured five-year revolving credit facilities to replace existing facilities. Each of these new facilities is scheduled to terminate on March 8, 2022. However, the Company and OG&E have the right to request an extension of the revolving credit facility termination date under their respective facility for an additional one-year period, which can be exercised up to two times. All such extension requests are subject to majority lender group approval (and only the commitments of those lenders that consent to such extension (or that agree to replace any non-consenting lender) will be extended for such additional period).

Borrowings under the new facilities bear interest at rates equal to either the eurodollar base rate (reserve adjusted, if applicable), plus a margin of 0.69 percent to 1.275 percent, or an alternate base rate, plus a margin of 0.00 percent to 0.275 percent. The new facilities have a facility fee that ranges from 0.06 percent to 0.225 percent. Interest rate margins and facility fees are based on the Company's and OG&E's then-current senior unsecured credit ratings, as applicable.

Each of the facilities provides for issuance of letters of credit, provided that (i) the aggregate outstanding credit exposure shall not exceed the amount of the revolving credit facility and (ii) the aggregate outstanding stated amount of letters of credit issued under such facility shall not exceed a specified maximum sublimit ($100 million for each of the Company and OG&E). Advances under the facilities may be used to refinance existing indebtedness and for working capital and general corporate purposes of the respective borrower and its subsidiaries, including commercial paper liquidity support, letters of credit, acquisitions and distributions.

Each of the facilities is unsecured and, under certain circumstances, may be increased (by up to $150 million in each case for the Company and OG&E) to a maximum revolving commitment limit of $600 million. Advances of revolving loans and letters of credit under the facilities are subject to certain conditions precedent, including the accuracy of certain representations and warranties and the absence of any default or unmatured default.

The Company and OG&E's facilities each have a financial covenant requiring that the respective borrower maintain a maximum debt to capitalization ratio of 65 percent, as defined in each such facility. The Company and OG&E's facilities each also contain covenants which restrict the respective borrower and certain of its subsidiaries in respect of, among other things, mergers and consolidations, sales of all or substantially all assets, incurrence of liens and transactions with affiliates. The Company and OG&E's facilities are each subject to acceleration upon the occurrence of any default, including, among others, payment defaults on such facilities, breach of representations, warranties and covenants, acceleration of indebtedness (other than intercompany and non-recourse indebtedness) of $100.0 million or more in the aggregate, change of control (as defined in each such facility), nonpayment of uninsured judgments in excess of $100.0 million and the occurrence of certain Employee Retirement Income Security Act and bankruptcy events, subject where applicable to specified cure periods.

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreement. As of December 31, 2017, the Company had $168.4 million of short-term debt compared to $236.2 million at December 31, 2016. The following table provides information regarding the Company's revolving credit agreements at December 31, 2017.

Entity	Aggregate Commitment	Amount Outstanding (A)	Weighted-Average Interest Rate	Expiration
	(In millions)			
OGE Energy (B)	$ 450.0	$ 168.4	1.62% (D)	March 8, 2022
OG&E (C)	450.0	0.3	0.95% (D)	March 8, 2022
Total	$ 900.0	$ 168.7	1.62%	

(A) Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at December 31, 2017.
(B) This bank facility is available to back up the Company's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility.
(C) This bank facility is available to back up OG&E's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility.
(D) Represents the weighted-average interest rate for the outstanding borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit.

The Company's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with the Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse rating impact occurs. The impact of any future downgrade could include an increase in the costs of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post collateral or letters of credit.

OG&E must obtain regulatory approval from the FERC in order to borrow on a short-term basis. OG&E has the necessary regulatory approvals to incur up to $800.0 million in short-term borrowings at any one time for a two-year period beginning January 1, 2017 and ending December 31, 2018.

11. Retirement Plans and Postretirement Benefit Plans

Pension Plan and Restoration of Retirement Income Plan

It is the Company's policy to fund the Pension Plan on a current basis based on the net periodic pension expense as determined by the Company's actuarial consultants. Such contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future. The Company made a $20.0 million contribution to its Pension Plan in both 2017 and 2016. The Company has not determined whether it will need to make any contributions to the Pension Plan in 2018. Any contribution to the Pension Plan during 2018 would be a discretionary contribution, anticipated to be in the form of cash, and is not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended. The Company could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future.

In accordance with ASC Topic 715, "Compensation - Retirement Benefits," a one-time settlement charge is required to be recorded by an organization when lump sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation during a plan year exceed the service cost and interest cost components of the organization’s net periodic pension cost. During 2017 and 2015, the Company experienced an increase in both the number of employees electing to retire and the amount of lump sum payments paid to such employees upon retirement. As a result, the Company recorded

pension settlement charges of $15.3 million in the fourth quarter of 2017 and $21.7 million during 2015. The pension settlement charges did not increase the Company's total pension expense over time, as the charges were an acceleration of costs that otherwise would be recognized as pension expense in future periods. During the quarter ended June 30, 2016, the Company experienced a settlement of its Supplemental Executive Retirement Plan and its non-qualified Restoration of Retirement Income Plan. As a result, the Company recorded pension settlement charges of $8.6 million during 2016.

The Company provides a Restoration of Retirement Income Plan to those participants in the Company's Pension Plan whose benefits are subject to certain limitations of the Code. Participants in the Restoration of Retirement Income Plan receive the same benefits that they would have received under the Company's Pension Plan in the absence of limitations imposed by the federal tax laws. The Restoration of Retirement Income Plan is intended to be an unfunded plan.

Obligations and Funded Status

The following table presents the status of the Company's Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans for 2017 and 2016. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion, which is recorded as a regulatory asset as discussed in Note 1) in the Company's Consolidated Balance Sheets. The amounts in Accumulated Other Comprehensive Loss and those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods. The benefit obligation for the Company's Pension Plan and the Restoration of Retirement Income Plan represents the projected benefit obligation, while the benefit obligation for the postretirement benefit plans represents the accumulated postretirement benefit obligation. The accumulated postretirement benefit obligation for the Company's Pension Plan and Restoration of Retirement Income Plan differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2017 was $626.9 million and $7.5 million, respectively. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2016 was $608.0 million and $6.1 million, respectively. The details of the funded status of the Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans and the amounts included in the Consolidated Balance Sheets are as follows:

	Pension Plan		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
December 31 *(In millions)*	**2017**	2016	**2017**	2016	**2017**	2016
Change in benefit obligation						
Beginning obligations	**$ 672.2**	$ 680.0	**$ 7.0**	$ 25.1	**$ 215.9**	$ 225.3
Service cost	**15.5**	15.8	**0.3**	0.3	**0.6**	0.8
Interest cost	**26.2**	25.5	**0.3**	0.4	**7.2**	9.5
Plan settlements	**(50.2)**	—	**—**	(20.6)	**(28.1)**	—
Plan amendments	**—**	—	**—**	—	**(39.6)**	—
Participants' contributions	**—**	—	**—**	—	**3.5**	3.6
Actuarial losses (gains)	**38.6**	4.7	**0.7**	1.8	**5.6**	(7.6)
Benefits paid	**(14.8)**	(53.8)	**(0.2)**	—	**(15.7)**	(15.7)
Ending obligations	**$ 687.5**	$ 672.2	**$ 8.1**	$ 7.0	**$ 149.4**	$ 215.9
Change in plans' assets						
Beginning fair value	**$ 595.9**	$ 581.7	**$ —**	$ —	**$ 53.1**	$ 55.3
Actual return on plans' assets	**84.4**	48.0	**—**	—	**2.8**	2.0
Employer contributions	**20.0**	20.0	**0.2**	20.6	**34.6**	7.9
Plan settlements	**(50.2)**	—	**—**	(20.6)	**(28.1)**	—
Participants' contributions	**—**	—	**—**	—	**3.5**	3.6
Benefits paid	**(14.8)**	(53.8)	**(0.2)**	—	**(15.7)**	(15.7)
Ending fair value	**$ 635.3**	$ 595.9	**$ —**	$ —	**$ 50.2**	$ 53.1
Funded status at end of year	**$ (52.2)**	$ (76.3)	**$ (8.1)**	$ (7.0)	**$ (99.2)**	$ (162.8)

Net Periodic Benefit Cost

	Pension Plan			Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year Ended December 31 *(In millions)*	**2017**	2016	2015	**2017**	2016	2015	**2017**	2016	2015
Service cost	**$ 15.5**	$ 15.8	$ 16.1	**$ 0.3**	$ 0.3	$ 1.3	**$ 0.6**	$ 0.8	$ 1.5
Interest cost	**26.2**	25.5	26.1	**0.3**	0.4	0.7	**7.2**	9.5	10.3
Expected return on plan assets	**(42.6)**	(41.5)	(46.0)	**—**	—	—	**(2.2)**	(2.3)	(2.4)
Amortization of net loss	**17.4**	16.5	18.0	**0.4**	0.7	0.6	**2.0**	2.6	13.9
Amortization of unrecognized prior service cost (A)	**(0.1)**	(0.1)	0.4	**0.1**	0.1	0.1	**(3.5)**	(8.8)	(16.5)
Settlement	**15.3**	—	21.7	**—**	8.6	—	**0.6**	—	—
Total net periodic benefit cost	**31.7**	16.2	36.3	**1.1**	10.1	2.7	**4.7**	1.8	6.8
Less: Amount paid by unconsolidated affiliates	**4.3**	5.1	4.2	**—**	0.3	0.1	**0.3**	0.2	1.3
Net periodic benefit cost (B)	**$ 27.4**	$ 11.1	$ 32.1	**$ 1.1**	$ 9.8	$ 2.6	**$ 4.4**	$ 1.6	$ 5.5

(A) Unamortized prior service cost is amortized on a straight-line basis over the average remaining service period to the first eligibility age of participants who are expected to receive a benefit and are active at the date of the plan amendment.

(B) In addition to the $32.9 million, $22.5 million and $40.2 million of net periodic benefit cost recognized in 2017, 2016 and 2015, respectively, OG&E recognized the following:

- a change in pension expense in 2017, 2016 and 2015 of $(2.3) million, $9.9 million and $(3.1) million, respectively, to maintain the allowable amount to be recovered for pension expense in the Oklahoma jurisdiction, which are included in the Pension tracker regulatory asset or liability (see Note 1);
- an increase in postretirement medical expense in 2017, 2016 and 2015 of $6.2 million, $7.9 million and $5.8 million, respectively, to maintain the allowable amount to be recovered for postretirement medical expense in the Oklahoma jurisdiction which are included in the Pension tracker regulatory asset or liability (see Note 1); and
- a deferral of pension expense in 2017, 2016 and 2015 of $1.1 million, $0.1 million and $1.9 million related to the Arkansas jurisdictional portion of the pension settlement charge of $15.3 million, $8.6 million and $21.7 million, respectively.

(In millions)	**2017**	2016	2015
Capitalized portion of net periodic pension benefit cost	**$ 4.4**	$ 4.0	$ 5.0
Capitalized portion of net periodic postretirement benefit cost	**1.2**	0.8	1.9

Rate Assumptions

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year Ended December 31	**2017**	2016	2015	**2017**	2016	2015
Discount rate	**3.60%**	4.00%	4.00%	**3.70%**	4.20%	4.25%
Rate of return on plans' assets	**7.50%**	7.50%	7.50%	**4.00%**	4.00%	4.00%
Compensation increases	**4.20%**	4.20%	4.20%	**N/A**	N/A	N/A
Assumed health care cost trend:						
Initial trend	**N/A**	N/A	N/A	**7.50%**	6.75%	6.10%
Ultimate trend rate	**N/A**	N/A	N/A	**4.50%**	4.50%	4.50%
Ultimate trend year	**N/A**	N/A	N/A	**2030**	2026	2026

N/A - not applicable

The discount rate used to compute the present value of plan liabilities is based generally on rates of high-grade corporate bonds with maturities similar to the average period over which benefits will be paid. The discount rate used to determine net benefit cost for the current year is the same discount rate used to determine the benefit obligation as of the previous year's balance sheet date.

The overall expected rate of return on plan assets assumption was 7.50 percent in both 2017 and 2016, which was used in determining net periodic benefit cost due to recent returns on the Company's long-term investment portfolio. The rate of return on plan assets assumption is the average long-term rate of earnings expected on the funds currently invested and to be invested for the purpose of providing benefits specified by the Pension Plan or postretirement benefit plans. This assumption is reexamined at least annually and updated as necessary. The rate of return on plan assets assumption reflects a combination of historical return analysis, forward-looking return expectations and the plans' current and expected asset allocation.

The assumed health care cost trend rates have a significant effect on the amounts reported for postretirement medical benefit plans. Future health care cost trend rates are assumed to be 6.50 percent in 2018 with the rates trending downward to 4.50 percent by 2026. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

ONE-PERCENTAGE POINT INCREASE			
Year Ended December 31 *(In millions)*	**2017**	2016	2015
Effect on aggregate of the service and interest cost components	**$ —**	$ —	$ —
Effect on accumulated postretirement benefit obligations	**0.1**	0.2	0.2

ONE-PERCENTAGE POINT DECREASE			
Year Ended December 31 *(In millions)*	**2017**	2016	2015
Effect on aggregate of the service and interest cost components	**$ —**	$ —	$ 0.1
Effect on accumulated postretirement benefit obligations	**0.3**	0.7	0.7

Pension Plan Investments, Policies and Strategies

The Pension Plan assets are held in a trust which follows an investment policy and strategy designed to reduce the funded status volatility of the Plan by utilizing liability driven investing. The purpose of liability-driven investing is to structure the asset portfolio to more closely resemble the pension liability and thereby more effectively hedge against changes in the liability. The investment policy follows a glide path approach that shifts a higher portfolio weighting to fixed income as the Plan's funded status increases. The table below sets forth the targeted fixed income and equity allocations at different funded status levels.

Projected Benefit Obligation Funded Status Thresholds	**<90%**	**95%**	**100%**	**105%**	**110%**	**115%**	**120%**
Fixed income	50%	58%	65%	73%	80%	85%	90%
Equity	50%	42%	35%	27%	20%	15%	10%
Total	100%	100%	100%	100%	100%	100%	100%

Within the portfolio's overall allocation to equities, the funds are allocated according to the guidelines in the table below.

Asset Class	**Target Allocation**	**Minimum**	**Maximum**
Domestic Large Cap Equity	40%	35%	60%
Domestic Mid-Cap Equity	15%	5%	25%
Domestic Small-Cap Equity	25%	5%	30%
International Equity	20%	10%	30%

The Company has retained an investment consultant responsible for the general investment oversight, analysis, monitoring investment guideline compliance and providing quarterly reports to certain of the Company's members and the Company's Investment Committee. The various investment managers used by the trust operate within the general operating objectives as established in the investment policy and within the specific guidelines established for each investment manager's respective portfolio.

The portfolio is rebalanced at least on an annual basis to bring the asset allocations of various managers in line with the target asset allocation listed above. More frequent rebalancing may occur if there are dramatic price movements in the financial markets which may cause the trust's exposure to any asset class to exceed or fall below the established allowable guidelines.

To evaluate the progress of the portfolio, investment performance is reviewed quarterly. It is, however, expected that performance goals will be met over a full market cycle, normally defined as a three to five year period. Analysis of performance is within the context of the prevailing investment environment and the advisors' investment style. The goal of the trust is to provide a rate of return consistently from three percent to five percent over the rate of inflation (as measured by the national Consumer Price Index) on a fee adjusted basis over a typical market cycle of no less than three years and no more than five years. Each investment manager is expected to outperform its respective benchmark. Below is a list of each asset class utilized with appropriate comparative benchmark(s) each manager is evaluated against:

Asset Class	Comparative Benchmark(s)
Active Duration Fixed Income	Bloomberg Barclays Aggregate
Long Duration Fixed Income	Duration blended Barclays Long Government/Credit & Barclays Universal
Equity Index	Standard & Poor's 500 Index
Mid-Cap Equity	Russell Midcap Index
	Russell Midcap Value Index
Small-Cap Equity	Russell 2000 Index
	Russell 2000 Value Index
International Equity	Morgan Stanley Capital Investment ACWI ex-U.S.

The fixed income managers are expected to use discretion over the asset mix of the trust assets in its efforts to maximize risk-adjusted performance. Exposure to any single issuer, other than the U.S. government, its agencies or its instrumentalities (which have no limits), is limited to five percent of the fixed income portfolio as measured by market value. At least 75 percent of the invested assets must possess an investment-grade rating at or above Baa3 or BBB- by Moody's Investors Services, Standard & Poor's Ratings Services or Fitch Ratings. The portfolio may invest up to 10 percent of the portfolio's market value in convertible bonds as long as the securities purchased meet the quality guidelines. A portfolio may invest up to 15 percent of the portfolio's market value in private placement, including 144A securities with or without registration rights and allow for futures to be traded in the portfolio. The purchase of any of the Company's equity, debt or other securities is prohibited.

The domestic value equity managers focus on stocks that the manager believes are undervalued in price and earn an average or less than average return on assets and often pays out higher than average dividend payments. The domestic growth equity manager will invest primarily in growth companies which consistently experience above average growth in earnings and sales, earn a high return on assets and reinvest cash flow into existing business. The domestic mid-cap equity portfolio manager focuses on companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell Midcap Index, small dividend yield, return on equity at or near the Russell Midcap Index and an earnings per share growth rate at or near the Russell Midcap Index. The domestic small-cap equity manager will purchase shares of companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell 2000, small dividend yield, return on equity at or near the Russell 2000 and an earnings per share growth rate at or near the Russell 2000. The international global equity manager invests primarily in non-dollar denominated equity securities. Investing internationally diversifies the overall trust across the global equity markets. The manager is required to operate under certain restrictions including regional constraints, diversification requirements and percentage of U.S. securities. The Morgan Stanley Capital International All Country World ex-U.S. Index is the benchmark for comparative performance purposes. The Morgan Stanley Capital International All Country World ex-U.S. Index is a market value weighted index designed to measure the combined equity market performance of developed and emerging markets countries, excluding the U.S. All of the equities which are purchased for the international portfolio are thoroughly researched. All securities are freely traded on a recognized stock exchange, and there are no over-the-counter derivatives. The following investment categories are excluded: options (other than traded currency options), commodities, futures (other than currency futures or currency hedging), short sales/margin purchases, private placements, unlisted securities and real estate (but not real estate shares).

For all domestic equity investment managers, no more than five percent can be invested in any one stock at the time of purchase and no more than 10 percent after accounting for price appreciation. Options or financial futures may not be purchased unless prior approval of the Company's Investment Committee is received. The purchase of securities on margin is prohibited as is securities lending. Private placement or venture capital may not be purchased. All interest and dividend payments must be swept on a daily basis into a short-term money market fund for re-deployment. The purchase of any of the Company's equity, debt or other securities is prohibited. The purchase of equity or debt issues of the portfolio manager's organization is also prohibited. The aggregate positions in any company may not exceed one percent of the fair market value of its outstanding stock.

Pension Plan Investments

The following tables summarize the Pension Plan's investments that are measured at fair value on a recurring basis at December 31, 2017 and 2016. There were no Level 3 investments held by the Pension Plan at December 31, 2017 and 2016.

(In millions)	December 31, 2017	Level 1	Level 2	Net Asset Value (A)
Common stocks	$ 225.9	$ 225.9	$ —	$ —
U.S. Treasury notes and bonds (B)	169.7	169.7	—	—
Mortgage- and asset-backed securities	43.4	—	43.4	—
Corporate fixed income and other securities	153.8	—	153.8	—
Commingled fund (C)	29.9	—	—	29.9
Foreign government bonds	4.0	—	4.0	—
U.S. municipal bonds	1.2	—	1.2	—
Money market fund	4.3	—	—	4.3
Mutual fund	7.8	7.8	—	—
Futures:				
U.S. Treasury futures (receivable)	13.4	—	13.4	—
U.S. Treasury futures (payable)	(11.4)	—	(11.4)	—
Cash collateral	0.3	0.3	—	—
Forward contracts:				
Receivable (foreign currency)	0.1	—	0.1	—
Total Pension Plan investments	$ 642.4	$ 403.7	$ 204.5	$ 34.2
Receivable from broker for securities sold	—			
Interest and dividends receivable	3.2			
Payable to broker for securities purchased	(10.3)			
Total Pension Plan assets	$ 635.3			

(In millions)	December 31, 2016	Level 1	Level 2	Net Asset Value (A)
Common stocks	$ 237.1	$ 237.1	$ —	$ —
U.S. Treasury notes and bonds (B)	122.3	122.3	—	—
Mortgage-backed securities	59.2	—	59.2	—
Corporate fixed income and other securities	137.6	—	137.6	—
Commingled fund (C)	23.8	—	—	23.8
Foreign government bonds	5.2	—	5.2	—
U.S. municipal bonds	1.9	—	1.9	—
Money market fund	2.2	—	—	2.2
Mutual fund	9.0	9.0	—	—
Futures:				
U.S. Treasury futures (receivable)	10.7	—	10.7	—
U.S. Treasury futures (payable)	(2.3)	—	(2.3)	—
Cash collateral	0.3	0.3	—	—
Forward contracts:				
Receivable (foreign currency)	0.2	—	0.2	—
Total Pension Plan investments	$ 607.2	$ 368.7	$ 212.5	$ 26.0
Receivable from broker for securities sold	—			
Interest and dividends receivable	3.0			
Payable to broker for securities purchased	(14.3)			
Total Pension Plan assets	$ 595.9			

(A) GAAP allows the measurement of certain investments that do not have a readily determinable fair value at the net asset value. These investments do not consider the observability of inputs; therefore, they are not included within the fair value hierarchy.

(B) This category represents U.S. Treasury notes and bonds with a Moody's Investors Services rating of Aaa and Government Agency Bonds with a Moody's Investors Services rating of A1 or higher.

(C) This category represents units of participation in a commingled fund that primarily invested in stocks of international companies and emerging markets.

The three levels defined in the fair value hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible by the Pension Plan at the measurement date. Instruments classified as Level 1 include investments in common stocks, U.S. Treasury notes and bonds, mutual funds and cash collateral.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. Instruments classified as Level 2 include corporate fixed income and other securities, mortgage- and asset-backed securities, U.S. municipal bonds, foreign government bonds, U.S. Treasury futures contracts and forward contracts.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the Plan's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk).

Postretirement Benefit Plans

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for eligible retired members. Regular, full-time, active employees hired prior to February 1, 2000 whose age and years of credited service total or exceed 80 or have attained at least age 55 with 10 or more years of service at the time of retirement are entitled to postretirement medical benefits, while employees hired on or after February 1, 2000 are not entitled to postretirement medical benefits. Eligible retirees must contribute such amount as the Company specifies from time to time toward the cost of coverage for postretirement benefits. The benefits are subject to deductibles, co-payment provisions and other limitations. OG&E charges

postretirement benefit costs to expense and includes an annual amount as a component of the cost-of-service in future ratemaking proceedings.

The Company's contribution to the medical costs for pre-65 aged eligible retirees are fixed at the 2011 level, and the Company covers future annual medical inflationary cost increases up to five percent. Increases in excess of five percent annually are covered by the pre-65 aged retiree in the form of premium increases. The Company provides Medicare-eligible retirees and their Medicare-eligible spouses an annual fixed contribution to a Company-sponsored health reimbursement arrangement. Medicare-eligible retirees are able to purchase individual insurance policies supplemental to Medicare through a third-party administrator and use their health reimbursement arrangement funds for reimbursement of medical premiums and other eligible medical expenses.

In August 2017, the Company adopted an amendment to the retiree medical plan. Effective January 1, 2018, the Company will reduce the amount of supplemental Medicare coverage for Medicare-eligible retirees, providing a fixed stipend based on current market analysis in August 2017. The Company will continue to allow those Medicare-eligible retirees to acquire coverage from a company-provided third-party administrator. The effect of these plan amendments is reflected in the Company's December 31, 2017 Consolidated Balance Sheet as a reduction to the postretirement benefit obligation of $42.9 million.

In August 2017, the Company settled the retiree life plan in its entirety and paid $26.4 million to participants in August 2017. No gain or loss was recognized upon settlement, and the effect of the settlement is reflected in the Company's December 31, 2017 Consolidated Balance Sheet as a reduction in the Accrued Benefit Obligations of $27.9 million and related other comprehensive income and regulatory asset of $2.1 million.

Postretirement Plans Investments

The following tables summarize the postretirement benefit plans' investments that are measured at fair value on a recurring basis at December 31, 2017 and 2016. There were no Level 2 investments held by the postretirement benefit plans at December 31, 2017 and 2016.

(In millions)	**December 31, 2017**	**Level 1**	**Level 3**
Group retiree medical insurance contract	**$ 40.2**	**$ —**	**$ 40.2**
Mutual funds investment:			
U.S. equity investments	**9.5**	**9.5**	**—**
Cash	**0.5**	**0.5**	**—**
Total plan investments	**$ 50.2**	**$ 10.0**	**$ 40.2**

(In millions)	December 31, 2016	Level 1	Level 3
Group retiree medical insurance contract	$ 44.7	$ —	$ 44.7
Mutual funds investment:			
U.S. equity investments	8.1	8.1	—
Money market funds investment	0.3	0.3	—
Total plan investments	$ 53.1	$ 8.4	$ 44.7

The group retiree medical insurance contract invests in a pool of common stocks, bonds and money market accounts, of which a significant portion is comprised of mortgage-backed securities. The unobservable input included in the valuation of the contract includes the approach for determining the allocation of the postretirement benefit plans' pro-rata share of the total assets in the contract.

The following table summarizes the postretirement benefit plans' investments that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

Year Ended December 31 *(In millions)*	2017
Group retiree medical insurance contract:	
Beginning balance	**$ 44.7**
Interest income	**0.8**
Dividend income	**0.5**
Net unrealized gains related to instruments held at the reporting date	**0.3**
Claims paid	**(5.9)**
Realized losses	**(0.1)**
Investment fees	**(0.1)**
Ending balance	**$ 40.2**

Medicare Prescription Drug, Improvement and Modernization Act of 2003

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 expanded coverage for prescription drugs. The following table summarizes the gross benefit payments the Company expects to pay related to its postretirement benefit plans, including prescription drug benefits.

(In millions)	Gross Projected Postretirement Benefit Payments
2018	$ 11.4
2019	11.5
2020	11.6
2021	11.6
2022	11.7
After 2022	48.6

The following table summarizes the benefit payments the Company expects to pay related to OGE Energy's Pension Plan and Restoration of Retirement Income Plan. These expected benefits are based on the same assumptions used to measure the Company's benefit obligation at the end of the year and include benefits attributable to estimated future employee service.

(In millions)	Projected Benefit Payments
2018	$ 65.6
2019	62.0
2020	63.4
2021	62.3
2022	61.1
After 2022	285.0

Post-Employment Benefit Plan

Disabled employees receiving benefits from the Company's Group Long-Term Disability Plan are entitled to continue participating in the Company's Medical Plan along with their dependents. The post-employment benefit obligation represents the actuarial present value of estimated future medical benefits that are attributed to employee service rendered prior to the date as of which such information is presented. The obligation also includes future medical benefits expected to be paid to current employees participating in the Company's Group Long-Term Disability Plan and their dependents, as defined in the Company's Medical Plan.

The post-employment benefit obligation is determined by an actuary on a basis similar to the accumulated postretirement benefit obligation. The estimated future medical benefits are projected to grow with expected future medical cost trend rates and

are discounted for interest at the discount rate and for the probability that the participant will discontinue receiving benefits from the Company's Group Long-Term Disability Plan due to death, recovery from disability or eligibility for retiree medical benefits. The Company's post-employment benefit obligation was $2.5 million and $2.4 million at December 31, 2017 and 2016, respectively.

401(k) Plan

The Company provides a 401(k) Plan, and each regular full-time employee of the Company or a participating affiliate is eligible to participate in the 401(k) Plan immediately. All other employees of the Company or a participating affiliate are eligible to become participants in the 401(k) Plan after completing one year of service as defined in the 401(k) Plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the 401(k) Plan, for that pay period. Participants who have reached age 50 before the close of a year are allowed to make additional contributions referred to as "Catch-Up Contributions," subject to certain limitations of the Code. Participants may designate, at their discretion, all or any portion of their contributions as: (i) a before-tax contribution under Section 401(k) of the Code subject to the limitations thereof, (ii) a contribution made on a non-Roth after-tax basis or (iii) a Roth contribution. The 401(k) Plan also includes an eligible automatic contribution arrangement and provides for a qualified default investment alternative consistent with the U.S. Department of Labor regulations. Participants may elect, in accordance with the 401(k) Plan procedures, to have his or her future salary deferral rate to be automatically increased annually on a date and in an amount as specified by the participant in such election. For employees hired or rehired on or after December 1, 2009, the Company contributes to the 401(k) Plan, on behalf of each participant, 200 percent of the participant's contributions up to five percent of compensation.

No Company contributions are made with respect to a participant's Catch-Up Contributions, rollover contributions or with respect to a participant's contributions based on overtime payments, pay-in-lieu of overtime for exempt personnel, special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. Once made, the Company's contribution may be directed to any available investment option in the 401(k) Plan. The Company match contributions vest over a three-year period. After two years of service, participants become 20 percent vested in their Company contribution account and become fully vested on completing three years of service. In addition, participants fully vest when they are eligible for normal or early retirement under the Pension Plan requirements, in the event of their termination due to death or permanent disability or upon attainment of age 65 while employed by the Company or its affiliates. The Company contributed $13.2 million, $11.9 million and $11.6 million in 2017, 2016 and 2015, respectively, to the 401(k) Plan.

Deferred Compensation Plan

The Company provides a nonqualified deferred compensation plan which is intended to be an unfunded plan. The plan's primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of the Company and to supplement such employees' 401(k) Plan contributions as well as offering this plan to be competitive in the marketplace.

Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70 percent of base salary and 100 percent of annual bonus awards or (ii) eligible employees may elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the 401(k) Plan with such deferrals to start when maximum deferrals to the qualified 401(k) Plan have been made because of limitations in that plan. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors' meeting fees and annual retainers. The Company matches employee (but not non-employee director) deferrals to make up for any match lost in the 401(k) Plan because of deferrals to the deferred compensation plan and to allow for a match that would have been made under the 401(k) Plan on that portion of either the first six percent of total compensation or the first five percent of total compensation, depending on prior participant elections, deferred that exceeds the limits allowed in the 401(k) Plan. Matching credits vest based on years of service, with full vesting after three years or, if earlier, on retirement, disability, death, a change in control of the Company or termination of the plan. Deferrals, plus any Company match, are credited to a recordkeeping account in the participant's name. Earnings on the deferrals are indexed to the assumed investment funds selected by the participant. In 2017, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company's common stock. The Company accounts for the contributions related to the Company's executive officers in this plan as Accrued Benefit Obligations, and the Company accounts for the contributions related to the Company's directors in this plan as Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheets. The investment associated with these contributions is accounted for as Other Property and Investments in the Consolidated Balance Sheets. The appreciation of these investments is accounted for as Other Income, and the increase in the liability under the plan is accounted for as Other Expense in the Consolidated Statements of Income.

12. Report of Business Segments

The Company reports its operations in two business segments: (i) the electric utility segment, which is engaged in the generation, transmission, distribution and sale of electric energy and (ii) natural gas midstream operations segment. Other Operations primarily includes the operations of the holding company.

Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations.

The following tables summarize the results of the Company's business segments for the years ended December 31, 2017, 2016 and 2015.

2017	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	**$ 2,261.1**	**$ —**	**$ —**	**$ —**	**$ 2,261.1**
Cost of sales	**897.6**	**—**	**—**	**—**	**897.6**
Other operation and maintenance	**486.1**	**0.3**	**(6.1)**	**—**	**480.3**
Depreciation and amortization	**280.9**	**—**	**2.6**	**—**	**283.5**
Taxes other than income	**84.8**	**1.0**	**3.6**	**—**	**89.4**
Operating income (loss)	**511.7**	**(1.3)**	**(0.1)**	**—**	**510.3**
Equity in earnings of unconsolidated affiliates	**—**	**131.2**	**—**	**—**	**131.2**
Other income (expense)	**74.0**	**0.1**	**(1.2)**	**(0.9)**	**72.0**
Interest expense	**138.4**	**—**	**6.3**	**(0.9)**	**143.8**
Income tax expense (benefit) (A)	**141.8**	**(195.2)**	**4.1**	**—**	**(49.3)**
Net income (loss)	**$ 305.5**	**$ 325.2**	**$ (11.7)**	**$ —**	**$ 619.0**
Investment in unconsolidated affiliates	**$ —**	**$ 1,151.9**	**$ 8.5**	**$ —**	**$ 1,160.4**
Total assets	**$ 9,255.6**	**$ 1,155.3**	**$ 109.1**	**$ (107.3)**	**$ 10,412.7**
Capital expenditures	**$ 824.1**	**$ —**	**$ —**	**$ —**	**$ 824.1**

(A) The Company recorded an income tax benefit of $245.2 million and income tax expense of $10.5 million during the fourth quarter of 2017 due to the Company remeasuring deferred taxes related to the natural gas midstream operations and other operations segments, respectively, as a result of the 2017 Tax Act. See Note 7 for further discussion of the effects of the 2017 Tax Act.

2016	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	$ 2,259.2	$ —	$ —	$ —	$ 2,259.2
Cost of sales	880.1	—	—	—	880.1
Other operation and maintenance	469.8	7.7	(11.9)	—	465.6
Depreciation and amortization	316.4	—	6.2	—	322.6
Taxes other than income	84.0	—	3.6	—	87.6
Operating income (loss)	508.9	(7.7)	2.1	—	503.3
Equity in earnings of unconsolidated affiliates	—	101.8	—	—	101.8
Other income (expense)	27.7	0.1	(4.3)	(0.2)	23.3
Interest expense	138.1	—	4.2	(0.2)	142.1
Income tax expense (benefit)	114.4	40.5	(6.8)	—	148.1
Net income	$ 284.1	$ 53.7	$ 0.4	$ —	$ 338.2
Investment in unconsolidated affiliates	$ —	$ 1,158.6	$ —	$ —	$ 1,158.6
Total assets	$ 8,669.4	$ 1,521.6	$ 89.0	$ (340.4)	$ 9,939.6
Capital expenditures	$ 660.1	$ —	$ —	$ —	$ 660.1

2015	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	$ 2,196.9	$ —	$ —	$ —	$ 2,196.9
Cost of sales	865.0	—	—	—	865.0
Other operation and maintenance	444.5	7.5	(0.4)	—	451.6
Depreciation and amortization	299.9	—	8.0	—	307.9
Taxes other than income	87.1	—	4.1	—	91.2
Operating income (loss)	500.4	(7.5)	(11.7)	—	481.2
Equity in earnings of unconsolidated affiliates (A)	—	15.5	—	—	15.5
Other income (expense)	20.0	0.4	0.9	(0.3)	21.0
Interest expense	146.7	—	2.6	(0.3)	149.0
Income tax expense (benefit)	104.8	(1.0)	(6.4)	—	97.4
Net income (loss)	$ 268.9	$ 9.4	$ (7.0)	$ —	$ 271.3
Investment in unconsolidated affiliates	$ —	$ 1,194.4	$ —	$ —	$ 1,194.4
Total assets	$ 8,525.5	$ 1,439.5	$ 174.6	$ (559.0)	$ 9,580.6
Capital expenditures	$ 551.6	$ —	$ (3.8)	$ —	$ 547.8

(A) The Company recorded a $108.4 million pre-tax charge during the third quarter of 2015 for its share of Enable's goodwill impairment, as adjusted for the basis difference. See Note 3 for further discussion of the goodwill impairment.

13. Commitments and Contingencies

Operating Lease Obligations

The Company has operating lease obligations expiring at various dates, primarily for OG&E railcar leases, OG&E wind farm land leases and the Company's noncancellable operating lease. Future minimum payments for noncancellable operating leases are as follows:

Year Ended December 31 *(In millions)*	2018	2019	2020	2021	2022	After 2022	Total
Operating lease obligations:							
Railcars	$ 1.7	$ 20.9	$ —	$ —	$ —	$ —	$ 22.6
Wind farm land leases	2.5	2.5	2.9	2.9	2.9	40.6	54.3
Noncancellable operating lease	0.6	—	—	—	—	—	0.6
Total operating lease obligations	$ 4.8	$ 23.4	$ 2.9	$ 2.9	$ 2.9	$ 40.6	$ 77.5

Payments for operating lease obligations were $6.2 million, $9.3 million and $7.7 million for the years ended December 31, 2017, 2016 and 2015, respectively.

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with a purchase option, covering 1,243 rotary gondola railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to fuel expense and are recovered through OG&E's tariffs and fuel adjustment clauses.

On December 17, 2015, OG&E renewed the lease agreement effective February 1, 2016. At the end of the new lease term, which is February 1, 2019, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $18.2 million. OG&E is also required to maintain all of the railcars it has under the operating lease.

OG&E Wind Farm Land Lease Agreements

OG&E has operating leases related to land for its Centennial, OU Spirit and Crossroads wind farms expiring at various dates. The Centennial lease has rent escalations which increase annually based on the Consumer Price Index. The OU Spirit and Crossroads leases have rent escalations which increase after five and 10 years. Although the leases are cancellable, OG&E is required to make annual lease payments as long as the wind turbines are located on the land. OG&E does not expect to terminate the leases until the wind turbines reach the end of their useful life.

Noncancellable Operating Lease

On August 29, 2012, the Company executed a five-year lease agreement for office space from September 1, 2013 to August 31, 2018. This lease has rent escalations which increase after five years and allows for leasehold improvements.

Other Purchase Obligations and Commitments

The Company's other future purchase obligations and commitments estimated for the next five years are as follows:

(In millions)	2018	2019	2020	2021	2022	Total
Other purchase obligations and commitments:						
Cogeneration capacity and fixed operation and maintenance payments	$ 72.8	$ 65.3	$ 53.2	$ 49.5	$ 45.4	$ 286.2
Expected cogeneration energy payments	35.7	35.6	35.9	37.1	38.3	182.6
Minimum fuel purchase commitments	139.8	36.2	24.6	24.6	24.6	249.8
Expected wind purchase commitments	58.7	56.5	56.9	57.3	57.8	287.2
Long-term service agreement commitments	7.9	41.9	2.4	2.4	2.4	57.0
Mustang Modernization expenditures	24.9	—	—	—	—	24.9
Environmental compliance plan expenditures	63.0	8.9	0.2	—	—	72.1
Total other purchase obligations and commitments	$ 402.8	$ 244.4	$ 173.2	$ 170.9	$ 168.5	$ 1,159.8

Public Utility Regulatory Policy Act of 1978

At December 31, 2017, OG&E has a QF contract with Oklahoma Cogeneration LLC which expires on August 31, 2019, and a QF contract with AES-Shady Point, Inc. which expires on January 15, 2023. These contracts were entered into pursuant to the Public Utility Regulatory Policy Act of 1978. Stated generally, the Public Utility Regulatory Policy Act of 1978 and the regulations thereunder promulgated by the FERC require OG&E to purchase power generated in a manufacturing process from a QF. The rate for such power to be paid by OG&E was approved by the OCC. The rate generally consists of two components: one is a rate for actual electricity purchased from the QF by OG&E, and the other is a capacity charge, which OG&E must pay the QF for having the capacity available. However, if no electrical power is made available to OG&E for a period of time (generally three months), OG&E's obligation to pay the capacity charge is suspended. The total cost of cogeneration payments is recoverable in rates from customers. For the 320 MWs AES-Shady Point, Inc. QF contract and the 120 MWs Oklahoma Cogeneration LLC QF contract, OG&E purchases 100 percent of the electricity generated by the QFs.

As part of the QF contract with AES-Shady Point Inc., OG&E had the option beginning in July 2017 to provide notice to AES-Shady Point Inc. to terminate the contract in January 2018. On July 17, 2017, OG&E and AES-Shady Point, Inc. amended the agreement to allow OG&E the ability, through July 17, 2018, to provide AES-Shady Point Inc. a termination notice that would terminate the agreement on January 15, 2019.

For the years ended December 31, 2017, 2016 and 2015, OG&E made total payments to cogenerators of $115.2 million, $124.8 million and $124.0 million, respectively, of which $63.0 million, $66.3 million and $69.5 million, respectively, represented capacity payments. All payments for purchased power, including cogeneration, are included in the Consolidated Statements of Income as Cost of Sales.

OG&E Minimum Fuel Purchase Commitments

OG&E has coal contracts for purchases through June 2018. As a participant in the SPP Integrated Marketplace, OG&E now purchases a relatively small percentage of its natural gas supply through long-term agreements. Alternatively, OG&E relies on a combination of natural gas call agreements, whereby OG&E has the right but not the obligation to purchase a defined quantity of natural gas, combined with day and intra-day purchases to meet the demands of the SPP Integrated Marketplace.

OG&E Wind Purchase Commitments

OG&E owns the 120 MW Centennial, 101 MW OU Spirit and 228 MW Crossroads wind farms. OG&E's current wind power portfolio also includes purchase power contracts with the following:

Company	Location	Term of Contract	Expiration of Contract	MWs
CPV Keenan	Woodward County, OK	20 years	2030	152.0
Edison Mission Energy	Dewey County, OK	20 years	2031	130.0
NextEra Energy	Blackwell, OK	20 years	2032	60.0
FPL Energy	Woodward, OK	15 years	2018	50.0

The following table summarizes OG&E's wind power purchases for the years ended December 31, 2017, 2016 and 2015.

Year Ended December 31 *(In millions)*	**2017**	2016	2015
CPV Keenan	**$ 29.0**	$ 29.2	$ 26.7
Edison Mission Energy	**22.1**	21.1	19.7
NextEra Energy	**7.4**	7.3	7.0
FPL Energy	**2.6**	3.4	3.2
Total wind power purchased	**$ 61.1**	$ 61.0	$ 56.6

OG&E Long-Term Service Agreement Commitments

OG&E has a long-term parts and service maintenance contract for the upkeep of the McClain Plant. In May 2013, a new contract was signed that is expected to run for the earlier of 128,000 factored-fired hours or 4,800 factored-fired starts. On December 30, 2015, the McClain Long-Term Service Agreement was amended to define the terms and conditions for the exchange of spare rotors between OG&E and General Electric International, Inc. Based on historical usage and current expectations for future usage, this contract is expected to run until 2031. The contract requires payments based on both a fixed and variable cost component, depending on how much the McClain Plant is used.

OG&E has a long-term parts and service maintenance contract for the upkeep of the Redbud Plant. In March 2013, the contract was amended to extend the contract coverage for an additional 24,000 factored-fired hours resulting in a maximum of the earlier of 144,000 factored-fired hours or 4,500 factored-fired starts. Based on historical usage and current expectations for future usage, this contract is expected to run until 2029. The contract requires payments based on both a fixed and variable cost component, depending on how much the Redbud Plant is used.

Enable Gas Transportation Agreement

OG&E contracts with Enable for firm non-notice load following gas transportation services under a five year contract. The contract will expire in April 2019. In 2016, OG&E entered into an additional gas transportation services contract with Enable which will be effective upon the conversion of units 4 and 5 at Muskogee from coal to gas.

Environmental Laws and Regulations

The activities of OG&E are subject to numerous stringent and complex federal, state and local laws and regulations governing environmental protection. These laws and regulations can change, restrict or otherwise impact OG&E's business activities in many ways, including the handling or disposal of waste material, planning for future construction activities to avoid or mitigate harm to threatened or endangered species and requiring the installation and operation of emissions control equipment. Failure to comply with these laws and regulations could result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Management believes that all of its operations are in substantial compliance with current federal, state and local environmental standards.

Environmental regulation can increase the cost of planning, design, initial installation and operation of OG&E's facilities. OG&E is managing several potentially material uncertainties about the scope and timing for the acquisition, installation and operation of additional pollution control equipment and compliance costs for a variety of the EPA rules that are being challenged in court. OG&E is unable to predict the financial impact of these matters with certainty at this time. Management continues to

evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

Air Quality Control System

On September 10, 2014, OG&E executed a contract for the design, engineering and fabrication of two circulating Dry Scrubber systems to be installed at Sooner Units 1 and 2. OG&E entered into an agreement on February 9, 2015 to install the Dry Scrubber systems. The Dry Scrubbers are expected to be completed in mid to late 2018. More detail regarding the ECP can be found under the "Pending Regulatory Matters" in Note 14.

Clean Power Plan

On October 23, 2015, the EPA published the final Clean Power Plan that established standards of performance for CO_2 emissions from existing fossil-fuel-fired power plants along with state-specific CO_2 reduction standards expressed as both rate-based (lbs./MWh) and mass-based (tons/yr.) goals. However, the rule was challenged in court when it was issued, and the U.S. Supreme Court issued orders staying implementation of the Clean Power Plan on February 9, 2016 pending resolution of the court challenges. The EPA published a proposal on October 16, 2017 to repeal the Clean Power Plan. In addition, the EPA published an Advance Notice of Proposed Rulemaking seeking comments on regulatory options for replacing the Clean Power Plan. The ultimate timing and impact of these standards on OG&E's operations cannot be determined with certainty at this time, although a requirement for significant reduction of CO_2 emissions from existing fossil-fuel-fired power plants ultimately could result in significant additional compliance costs that would affect the Company's future consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates.

Other

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by GAAP, an estimate is made of the loss, and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. At the present time, based on current available information, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

14. Rate Matters and Regulation

Regulation and Rates

OG&E's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E's transmission activities, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the U.S. Department of Energy has jurisdiction over some of OG&E's facilities and operations. In 2017, 85 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and seven percent to the FERC.

The OCC issued an order in 1996 authorizing OG&E to reorganize into a subsidiary of the Company. The order required that, among other things, (i) the Company permit the OCC access to the books and records of the Company and its affiliates relating to transactions with OG&E, (ii) the Company employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers and (iii) the Company refrain from pledging OG&E assets or income for affiliate transactions. In addition, the Energy Policy Act of 2005 enacted the Public Utility Holding Company Act of 2005, which in turn granted to the FERC access to the books and records of the Company and its affiliates as the FERC deems relevant to costs incurred by OG&E or necessary or appropriate for the protection of utility customers with respect to the FERC jurisdictional rates.

Completed Regulatory Matters

Arkansas Rate Case Filing

On August 25, 2016, OG&E filed a general rate case with the APSC. The rate filing requested a $16.5 million rate increase based on a 10.25 percent return on equity. The requested rate increase was based on a June 30, 2016 test year and included recovery of over $3.0 billion of electric infrastructure additions since the last Arkansas general rate case in 2011. The requested

increase also reflected increases in operation and maintenance expenses, including vegetation management and increased recovery of depreciation and dismantlement costs.

In May 2017, the APSC approved a settlement between OG&E and the staff of the APSC and other intervenors. The settlement provided for a $7.1 million annual rate increase and a 9.5 percent return on equity on a 50.0 percent equity capital structure.

The settlement also provided that OG&E will be regulated under a formula rate rider, which should result in a more efficient process as the return on equity, depreciation rates and capital structure should not change from what was approved by the APSC in this settlement. The formula rate rider provides for an adjustment to rates if the earned rate of return falls outside of a plus or minus 50 basis point dead-band around the allowed return on equity. Adjustments are limited to plus or minus four percent of revenue for each rate class for the 12 months preceding the projected year. The initial term for the formula rate rider is not to exceed five years, unless additional approval is obtained from the APSC. OG&E expects to make its first filing under the Arkansas Formula Rate Rider in October 2018.

Fuel Adjustment Clause Review for Calendar Year 2015

On September 8, 2016, the OCC staff filed an application to review OG&E's fuel adjustment clause for calendar year 2015, including the prudence of OG&E's electric generation, purchased power and fuel procurement costs. On October 12, 2017, the OCC issued an order finding that, for the calendar year 2015, OG&E's electric generation, purchased power and fuel procurement processes and costs were prudent.

Oklahoma Rate Case Filing - 2015

On December 18, 2015, OG&E filed a general rate case with the OCC requesting a rate increase of $92.5 million and a 10.25 percent return on equity based on a common equity percentage of 53.0 percent. The rate case was based on a June 30, 2015 test year and included recovery of $1.6 billion of electric infrastructure additions since its last general rate case in Oklahoma.

On July 1, 2016, OG&E implemented an annual interim rate increase of $69.5 million, subject to refund for amounts in excess of the rates approved by the OCC.

In December 2016, the ALJ issued a report and recommendations in the case. The ALJ's recommendations included, among other things, the use of OG&E's actual capital structure of 53.0 percent equity and 47.0 percent long-term debt and a return on equity of 9.87 percent resulting in an annual increase in OG&E's revenues of $40.7 million.

During February and March 2017, the OCC held hearings and, on March 20, 2017, issued an order. The order resulted in an annual net increase of approximately $8.8 million in OG&E's rates to its Oklahoma retail customers. Although the order adopted certain recommendations set forth in the ALJ report, it differed in certain key respects.

The primary adjustments to the ALJ report consist of: (i) Oklahoma retail authorized rate of return on equity of 9.50 percent, (ii) depreciation expense is reduced by approximately $28.6 million from the ALJ report or $36.4 million from then current rates on an annual basis, (iii) recovery of 50.0 percent of short-term incentive compensation and no recovery of long-term incentive compensation, (iv) recovery of OG&E's requested vegetation management expenses and (v) recovery of production tax credits expiring in 2017 and air quality control systems consumable costs through the fuel adjustment clause. The order maintained OG&E's existing capital structure of 53.0 percent equity and 47.0 percent long-term debt.

As a result of the March 2017 OCC rate order, OG&E recorded, in the first quarter of 2017, adjustments to depreciation expense, amortization of regulatory assets and liabilities and impacts to the fuel adjustment clause effective July 1, 2016. On May 1, 2017, OG&E implemented new rates and began refunding excess amounts that it had collected in interim rates.

As of November 30, 2017, OG&E had completed the refund of $47.5 million collected in excess interim rates.

Mustang Modernization Plan - Arkansas

On August 15, 2017, OG&E filed for a determination with the APSC that the Mustang facility is in the public interest. The filing did not seek recovery for any costs associated with the Mustang Modernization Plan, as request for recovery of costs will take place with the first formula rate filing expected to be made in October 2018. On January 2, 2018, the APSC issued an order finding the Mustang Modernization Plan to be in the public interest.

Pending Regulatory Matters

Set forth below is a list of various proceedings pending before state or federal regulatory agencies. Unless stated otherwise, OG&E cannot predict when the regulatory agency will act or what action the regulatory agency will take. OG&E's financial results are dependent in part on timely and adequate decisions by the regulatory agencies that set OG&E's rates.

Environmental Compliance Plan

On August 6, 2014, OG&E filed an application with the OCC for approval of its plan to comply with the EPA's MATS and Regional Haze Rule FIP while serving the best long-term interests of customers in light of future environmental uncertainties. The application sought approval of the ECP and for a recovery mechanism for the associated costs. The ECP includes installing Dry Scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas. The application also asked the OCC to predetermine the prudence of its Mustang Modernization Plan and approval for a recovery mechanism for the associated costs.

On December 2, 2015, OG&E received an order from the OCC denying its plan to comply with the environmental mandates of the Federal Clean Air Act, Regional Haze Rule and MATS. The OCC also denied OG&E's request for pre-approval of its Mustang Modernization Plan, revised depreciation rates for both the retirement of the Mustang units and the replacement combustion turbines and pre-approval of early retirement and replacement of generating units at its Mustang site, including cost recovery through a rider.

On February 12, 2016, OG&E filed an application requesting the OCC to issue an order approving its decision to install Dry Scrubbers at the Sooner facility. OG&E's application did not seek approval of the costs of the Dry Scrubber project. Instead, the reasonableness of the costs would be considered after the project is completed, and OG&E seeks recovery in a general rate case. On April 28, 2016, the OCC approved the Dry Scrubber project.

Two parties appealed the OCC's decision to the Oklahoma Supreme Court. The Company is unable to predict what action the Oklahoma Supreme Court may take or the timing of any such action.

OG&E anticipates the total cost of Dry Scrubbers will be $542.4 million, including allowance for funds used during construction and capitalized ad valorem taxes and expects the project to be completed in mid to late 2018. As of December 31, 2017, OG&E had invested $401.3 million in the Dry Scrubbers. OG&E anticipates the total cost for the Mustang Modernization Plan will be $390.0 million, including allowance for funds used during construction and capitalized ad valorem taxes and expects the project to be completed in early 2018. As of December 31, 2017, OG&E had invested $348.4 million in the Mustang Modernization Plan.

Integrated Resource Plans

In October 2015, OG&E finalized the 2015 IRP and submitted it to the OCC. The 2015 IRP updated certain assumptions contained in the IRP submitted in 2014 but did not make any material changes to the ECP and other parts of the plan. Currently, OG&E is scheduled to update its IRP in Oklahoma by October 1, 2018 and in Arkansas by October 31, 2018.

Demand Program Rider - Energy Efficiency Lost Net Revenues

During the May 2017 implementation of new rates, OG&E reserved $5.6 million, pending resolution of a dispute with the OCC's Public Utility Division staff, regarding recovery of certain lost revenues associated with energy efficiency incurred prior to the March 2017 OCC rate order. These lost revenues are included within the total Demand Program Rider regulatory asset balance of $31.6 million as disclosed in Note 1.

Fuel Adjustment Clause Review for Calendar Year 2016

On August 3, 2017, the OCC staff filed an application to review OG&E's fuel adjustment clause for calendar year 2016, including the prudence of OG&E's electric generation, purchased power and fuel procurement costs. On February 7, 2018, an intervenor filed a recommendation to disallow the Oklahoma jurisdictional portion of $3.3 million related to wind sales in the SPP. A hearing is scheduled for March 29, 2018.

Oklahoma Rate Case Filing - 2018

On January 16, 2018, OG&E filed a general rate case in Oklahoma, requesting a rate increase of $1.9 million per year, assuming a 9.9 percent return on equity. The filing seeks recovery of the seven Mustang combustion turbines that are part of the Mustang Modernization Plan, requests an increase in depreciation rates to levels similar with rates in existence prior to the March 2017 OCC rate order and credits customers for the impacts of the 2017 Tax Act, enacted on December 22, 2017.

On December 22, 2017, the Attorney General of Oklahoma requested that the OCC reduce the rates and charges for electric service and provide for any refund due to the customers of OG&E resulting from the 2017 Tax Act. In response, on January 4, 2018, the OCC ordered OG&E to record a reserve, beginning on January 4, 2018, to reflect the reduced federal corporate tax rate of 21 percent and the amortization of excess accumulated deferred income tax and any other tax implications of the 2017 Tax Act on an interim basis, subject to refund until utility rates are adjusted to reflect the federal tax savings and a final order is issued in OG&E's pending rate case filed on January 16, 2018. Further, the OCC ordered the amounts of any refunds of such reserves owed to customers should accrue interest at a rate equivalent to OG&E's cost of capital as previously recognized in the March 2017 OCC rate order.

APSC Order - 2017 Tax Act

On January 12, 2018, as a result of the 2017 Tax Act, the APSC ordered OG&E to prepare and file an analysis, within 30 days of this order, of the ratemaking effects of the 2017 Tax Act on OG&E's revenue requirement and begin, effective January 1, 2018, to book regulatory liabilities to record the current and deferred impacts of the 2017 Tax Act. The APSC will subsequently solicit comments or testimony regarding the extent of the impacts of the 2017 Tax Act and how any resulting benefits, including carrying charges, should be returned to customers.

FERC - Section 206 Filing

In January 2018, the Oklahoma Municipal Power Authority filed a complaint at the FERC stating that the base return on common equity used by OG&E in calculating formula transmission rates under the SPP Open Access Transmission Tariff is unjust and unreasonable and should be reduced from 10.60 percent to 7.85 percent, effective upon the date of the complaint. The Company is analyzing the potential impact of the complaint but estimates that if the FERC ultimately orders a reduction, each 25 basis point reduction in the requested return on equity would reduce the Company's SPP Open Access Transmission Tariff transmission revenues by approximately $1.5 million annually. In addition to the request to reduce the return on equity, the Oklahoma Municipal Power Authority's complaint also requests that modifications be made to OG&E's transmission formula rates to reflect the impacts of the 2017 Tax Act. Although the proceeding is in the early stages, OG&E expects to contest the reduction of its base return on equity. The Company is unable to predict what action the FERC will take in response to the Oklahoma Municipal Power Authority's complaint or the timing of such action. However, if the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could have a material adverse effect on the Company's consolidated financial position, results of operations and cash flows.

15. Quarterly Financial Data (Unaudited)

Due to the seasonal fluctuations and other factors of the Company's businesses, the operating results for interim periods are not necessarily indicative of the results that may be expected for the year. In the Company's opinion, the following quarterly financial data includes all adjustments, consisting of normal recurring adjustments, necessary to fairly present such amounts. Summarized consolidated quarterly unaudited financial data is as follows:

Quarter Ended (*In millions, except per share data)*		March 31	June 30	September 30	December 31	Total
Operating revenues	**2017**	**$ 456.0**	**$ 586.4**	**$ 716.8**	**$ 501.9**	**$ 2,261.1**
	2016	$ 433.1	$ 551.4	$ 743.9	$ 530.8	$ 2,259.2
Operating income	**2017**	**$ 43.8**	**$ 143.5**	**$ 243.3**	**$ 79.7**	**$ 510.3**
	2016	$ 37.9	$ 125.9	$ 257.3	$ 82.2	$ 503.3
Net income	**2017**	**$ 36.0**	**$ 104.8**	**$ 183.4**	**$ 294.8**	**$ 619.0**
	2016	$ 25.2	$ 71.5	$ 183.6	$ 57.9	$ 338.2
Basic earnings per average common share (A)	**2017**	**$ 0.18**	**$ 0.52**	**$ 0.92**	**$ 1.48**	**$ 3.10**
	2016	$ 0.13	$ 0.35	$ 0.92	$ 0.29	$ 1.69
Diluted earnings per average common share (A)	**2017**	**$ 0.18**	**$ 0.52**	**$ 0.92**	**$ 1.48**	**$ 3.10**
	2016	$ 0.13	$ 0.35	$ 0.92	$ 0.29	$ 1.69

(A) Due to the impact of dilution on the earnings per share calculation, quarterly earnings per share amounts may not add to the total.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of OGE Energy Corp.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of OGE Energy Corp. (the "Company") as of December 31, 2017 and 2016, and the related consolidated statements of income, comprehensive income, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and financial statement schedule listed in the Index at Item 15(a) (collectively referred to as the "financial statements"). In our opinion, based on our audits and the report of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2017 and 2016, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We did not audit the consolidated financial statements of Enable Midstream Partners, LP ("Enable"), a partnership in which the Company has a 25.7 percent interest at December 31, 2017. The Company's investment in Enable constituted 11.1 percent and 11.7 percent of the Company's total assets as of December 31, 2017 and 2016, respectively, and the Company's equity earnings in the net income of Enable constituted 23.0 percent, 20.9 percent and 4.2 percent of the Company's income before taxes for the years ended December 31, 2017, 2016 and 2015, respectively. Those statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Enable, is based solely on the report of the other auditors.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 21, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2002.

Oklahoma City, Oklahoma
February 21, 2018

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer and chief financial officer, allowing timely decisions regarding required disclosure. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company's management, including the chief executive officer and chief financial officer, of the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934), the chief executive officer and chief financial officer have concluded that the Company's disclosure controls and procedures are effective.

No change in the Company's internal control over financial reporting has occurred during the Company's most recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934).

Management's Report on Internal Control Over Financial Reporting

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control system was designed to provide reasonable assurance to the Company's management and Board of Directors regarding the preparation and fair presentation of published financial statements. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2017. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework (2013). Based on our assessment, we believe that, as of December 31, 2017, the Company's internal control over financial reporting is effective based on those criteria.

The Company's independent auditors have issued an attestation report on the Company's internal control over financial reporting. This report appears on the following page.

/s/ Sean Trauschke	/s/ Scott Forbes
Sean Trauschke, Chairman of the Board, President and Chief Executive Officer	Scott Forbes, Controller and Chief Accounting Officer

/s/ Stephen E. Merrill

Stephen E. Merrill
Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of OGE Energy Corp.

Opinion on Internal Control over Financial Reporting

We have audited OGE Energy Corp.'s internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, OGE Energy Corp. (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the 2017 consolidated financial statements of the Company and our report dated February 21, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma

February 21, 2018

Item 9B. Other Information.

On February 16, 2018, the Company's Board of Directors elected a new director, Peter D. Clarke, to a term beginning on February 19, 2018 and expiring at the Company's Annual Meeting of Shareholders scheduled for May 17, 2018, at which time he is expected to be nominated for approval by the Company's shareholders. Mr. Clarke will receive compensation for his Board service consistent with compensation received by the Company's other non-employee directors (which is described in Exhibit 10.12 to this Form 10-K).

Mr. Clarke, 67, recently retired from the law firm of Jones Day following more than 40 years of representing the public utility and energy industries. Mr. Clarke's energy practice focused on corporate finance, disclosure obligations under the federal securities laws, corporate governance and mergers and acquisitions.

Jones Day provided legal services on a variety of matters on the Company's behalf during 2017 while Mr. Clarke was Of Counsel at Jones Day. Mr. Clarke retired from Jones Day on December 31, 2017. For the period of time from January 1, 2017 to February 15, 2018, Jones Day received fees from the Company for these services in the total amount of $4,315,445. Mr. Clarke was among a number of lawyers who provided those services; however, Mr. Clarke did not receive any direct compensation from legal fees the Company paid to Jones Day.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Code of Ethics Policy

OGE Energy maintains a code of ethics for our chief executive officer and senior financial officers, including the chief financial officer and chief accounting officer, which is available for public viewing on OGE Energy's website address www.oge.com under the heading "Investors," "Investor Relations," "Corporate Governance." The code of ethics will be provided, free of charge, upon request. OGE Energy intends to satisfy the disclosure requirements under Section 5, Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the code of ethics by posting such information on its website at the location specified above. OGE Energy will also include in its proxy statement information regarding the Audit Committee financial experts.

Item 11. Executive Compensation.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

Item 14. Principal Accounting Fees and Services.

Items 10 through 14 (other than Item 10 information regarding the Code of Ethics) are omitted pursuant to General Instruction G of Form 10-K, because the Company will file copies of a definitive proxy statement with the Securities and Exchange Commission on or about April 2, 2018. Such proxy statement is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) 1. Financial Statements

(i) The following Consolidated Financial Statements are included in Part II, Item 8 of this Annual Report:

- Consolidated Statements of Income for the years ended December 31, 2017, 2016 and 2015
- Consolidated Statements of Comprehensive Income for the years ended December 31, 2017, 2016 and 2015
- Consolidated Statements of Cash Flows for the years ended December 31, 2017, 2016 and 2015
- Consolidated Balance Sheets at December 31, 2017 and 2016
- Consolidated Statements of Capitalization at December 31, 2017 and 2016
- Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2017, 2016 and 2015
- Notes to Consolidated Financial Statements
- Report of Independent Registered Public Accounting Firm (Audit of Financial Statements)
- Management's Report on Internal Control Over Financial Reporting
- Report of Independent Registered Public Accounting Firm (Audit of Internal Control over Financial Reporting)

(ii) The financial statements and Notes to Consolidated Financial Statements of Enable Midstream Partners, LP, required pursuant to Rule 3-09 of Regulation S-X are filed as Exhibit 99.02

2. Financial Statement Schedule (included in Part IV)

- Schedule II - Valuation and Qualifying Accounts

All other schedules have been omitted since the required information is not applicable or is not material, or because the information required is included in the respective Consolidated Financial Statements or Notes thereto.

3. Exhibits

Exhibit No.	Description
2.01	Asset Purchase Agreement, dated as of August 18, 2003 by and between OG&E and NRG McClain LLC. (Certain exhibits and schedules were omitted and registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed August 20, 2003 (File No. 1-12579) and incorporated by reference herein).
2.02	Amendment No. 1 to Asset Purchase Agreement, dated as of October 22, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein).
2.03	Amendment No. 2 to Asset Purchase Agreement, dated as of October 27, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.04 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein).
2.04	Amendment No. 3 to Asset Purchase Agreement, dated as of November 25, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.05 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein).
2.05	Amendment No. 4 to Asset Purchase Agreement, dated as of January 28, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.06 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein).
2.06	Amendment No. 5 to Asset Purchase Agreement, dated as of February 13, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.07 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein).
2.07	Amendment No. 6 to Asset Purchase Agreement, dated as of March 12, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein).
2.08	Amendment No. 7 to Asset Purchase Agreement, dated as of April 15, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.02 to OGE Energy's Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein).
2.09	Amendment No. 8 to Asset Purchase Agreement, dated as of May 15, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein).
2.10	Amendment No. 9 to Asset Purchase Agreement, dated as of June 2, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.02 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein).
2.11	Amendment No. 10 to Asset Purchase Agreement, dated as of June 17, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein).
2.12	Purchase and Sale Agreement, dated as of January 21, 2008, entered into by and among Redbud Energy I, LLC, Redbud Energy II, LLC and Redbud Energy III, LLC and OG&E. (Certain exhibits and schedules hereto have been omitted and the registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein).
2.13	Asset Purchase Agreement, dated as of January 21, 2008, entered into by and among OG&E, the Oklahoma Municipal Power Authority and the Grand River Dam Authority. (Certain exhibits and schedules hereto have been omitted and the registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.02 to OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein).
2.14	Master Formation Agreement dated as of March 14, 2013 by and among CenterPoint Energy, Inc., OGE Energy Corp., Bronco Midstream Holdings, LLC and Bronco Midstream Holdings II, LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed March 15, 2013 (File No. 1-12579) and incorporated by reference herein).
3.01	Copy of Restated OGE Energy Corp. Certificate of Incorporation. (Filed as Exhibit 3.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12579) and incorporated by reference herein).
3.02	Copy of Amended OGE Energy Corp. By-laws dated February 22, 2017. (Filed as Exhibit 3.01 to OGE Energy's Form 8-K filed February 23, 2017 (File No. 1-12579) and incorporated by reference herein).
4.01	Trust Indenture dated October 1, 1995, from OG&E to Boatmen's First National Bank of Oklahoma, Trustee. (Filed as Exhibit 4.29 to OG&E's Registration Statement No. 33-61821 and incorporated by reference herein).
4.02	Supplemental Indenture No. 2, dated as of July 1, 1997, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed July 17, 1997 (File No. 33-1532) and incorporated by reference herein).

4.03	Supplemental Indenture No. 3, dated as of April 1, 1998, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed April 16, 1998 (File No. 33-1532) and incorporated by reference herein).
4.04	Supplemental Indenture No. 5 dated as of October 24, 2001, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.06 to OG&E's Registration Statement No. 333-104615 and incorporated by reference herein).
4.05	Supplemental Indenture No. 6 dated as of August 1, 2004, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to OG&E's Form 8-K filed August 6, 2004 (File No 1-1097) and incorporated by reference herein).
4.06	Supplemental Indenture No. 7 dated as of January 1, 2006 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to OG&E's Form 8-K filed January 6, 2006 (File No. 1-1097) and incorporated by reference herein).
4.07	Supplemental Indenture No. 8 dated as of January 15, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed January 31, 2008 (File No. 1-1097) and incorporated by reference herein).
4.08	Supplemental Indenture No. 9 dated as of September 1, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed September 9, 2008 (File No. 1-1097) and incorporated by reference herein).
4.09	Supplemental Indenture No. 10 dated as of December 1, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed December 11, 2008 (File No. 1-1097) and incorporated by reference herein).
4.10	Supplemental Indenture No. 11 dated as of June 1, 2010 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed June 8, 2010 (File No. 1-1097) and incorporated by reference herein).
4.11	Supplemental Indenture No. 12 dated as of May 15, 2011 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed May 27, 2011 (File No. 1-1097) and incorporated by reference herein).
4.12	Supplemental Indenture No. 13 dated as of May 1, 2013 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed May 13, 2013 (File No. 1-1097) and incorporated by reference herein).
4.13	Supplemental Indenture No. 14 dated as of March 15, 2014 being supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed March 25, 2014 (File No. 1-1097) and incorporated by reference herein).
4.14	Supplemental Indenture No. 15 dated as of December 1, 2014 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed December 11, 2014 (File No. 1-1097) and incorporated by reference herein).
4.15	Supplemental Indenture No. 16 dated as of March 15, 2017 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed March 31, 2017 (File No. 1-1097) and incorporated by reference herein).
4.16	Supplemental Indenture No. 17 dated as of August 1, 2017 being supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed August 11, 2017 (File No. 1-1097) and incorporated by reference herein).
4.17	Indenture dated as of November 1, 2004 between OGE Energy Corp. and UMB Bank, N.A., as trustee. (Filed as Exhibit 4.01 to OGE Energy's Form 8-K filed November 12, 2004 (File No. 1-12579) and incorporated by reference herein).
4.18	Supplemental Indenture No. 2 dated as of November 24, 2014 between OGE Energy and UMB Bank, N.A, as trustee, creating the Senior Notes. (Filed as Exhibit 4.01 to OGE Energy's Form 8-K filed November 24, 2014 (File No. 1-12579) and incorporated by reference herein).
10.01	Amended and Restated Facility Operating Agreement for the McClain Generating Facility dated as of July 9, 2004 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein).
10.02	Amended and Restated Ownership and Operation Agreement for the McClain Generating Facility dated as of July 9, 2004 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein).
10.03	Operating and Maintenance Agreement for the Transmission Assets of the McClain Generating Facility dated as of August 25, 2003 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.05 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein).
10.04*	Form of Split Dollar Agreement. (Filed as Exhibit 10.32 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein).

10.05	Credit Agreement dated as of March 8, 2017 by and among OGE Energy Corp. and JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Banks, Ltd., MUFG Union Bank, N.A., Royal Bank of Canada and U.S. Bank National Association, as Co-Documentation Agents, and the lenders from time to time parties thereto. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed March 8, 2017 (File No. 1-12579) and incorporated by reference herein).
10.06	Credit Agreement dated as of March 8, 2017 by and among Oklahoma Gas and Electric Company and JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Banks, Ltd., MUFG Union Bank, N.A., Royal Bank of Canada and U.S. Bank National Association, as Co-Documentation Agents, and the lenders from time to time parties thereto. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed March 8, 2017 (File No. 1-12579) and incorporated by reference herein).
10.07*	OGE Energy Supplemental Executive Retirement Plan, as amended and restated. (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein).
10.08*	OGE Energy Restoration of Retirement Income Plan, as amended and restated. (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein).
10.09*	Form of Employment Agreement for all existing and future officers of OGE Energy relating to change of control. (Filed as Exhibit 10.28 to OGE Energy's Form 10-K for the year ended December 31, 2011 (File No. 1-12579) and incorporated by reference herein).
10.10	Agreement, dated February 17, 2010, between OG&E and Oklahoma Department of Environmental Quality. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed February 23, 2010 (File No. 1-12579) and incorporated by reference herein).
10.11*	Amendment No. 1 to OGE Energy's Restoration of Retirement Income Plan. (Filed as Exhibit 10.40 to OGE Energy's Form 10-K for the year ended December 31, 2009 (File No. 1-12579) and incorporated by reference herein).
10.12*	Director Compensation.
10.13*	Executive Officer Compensation.
10.14	Fifth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP, dated November 14, 2017. (Filed as Exhibit 3.1 to Enable Midstream Partners, LP's Form 8-K filed November 15, 2017 (File No. 1-36413) and incorporated by reference herein).
10.15	Third Amended and Restated Limited Liability Company Agreement of Enable GP, LLC, dated June 22, 2016. (Filed as Exhibit 10.02 to OGE Energy's Form 8-K filed June 28, 2016 (File No. 1-12579) and incorporated by reference herein).
10.16	Registration Rights Agreement dated as of May 1, 2013 by and among CenterPoint Energy Field Services LP, CenterPoint Energy Resources Corp., OGE Enogex Holdings LLC, and Enogex Holdings LLC (Filed as Exhibit 10.03 to OGE Energy's Form 8-K filed May 7, 2013 (File No. 1-12579) and incorporated by reference herein).
10.17	Omnibus Agreement dated as of May 1, 2013 among CenterPoint Energy, Inc., OGE Energy Corp., Enogex Holdings LLC and CenterPoint Energy Field Services LP (Filed as Exhibit 10.04 to OGE Energy's Form 8-K filed May 7, 2013 (File No. 1-12579) and incorporated by reference herein).
10.18*	OGE Energy's 2013 Stock Incentive Plan. (Filed as Annex B to OGE Energy's Proxy Statement for the 2013 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein).
10.19*	OGE Energy's 2013 Annual Incentive Compensation Plan. (Filed as Annex C to OGE Energy's Proxy Statement for the 2013 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein).
10.20*	OGE Energy Corp. Involuntary Severance Benefits Plans for Non-Officers (Applicable only to non-officers of Enogex LLC seconded to Enable Midstream Partners, LP or Enable GP, LLC or one of its subsidiaries) (Filed as Exhibit 10.02 to OGE Energy's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12579) and incorporated by reference herein).
10.21*	OGE Energy Corp. Involuntary Severance Benefits Plans for Officers (Applicable only to officers of Enogex LLC seconded to Enable Midstream Partners, LP or Enable GP, LLC or one of its subsidiaries) (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12579) and incorporated by reference herein).
10.22*	Retention Agreement effective as of October 24, 2013, by and between OGE Enogex Holdings, LLC and E. Keith Mitchell (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12579) and incorporated by reference herein).
10.23*	Form of Performance Unit Agreement under OGE Energy's 2013 Stock Incentive Plan. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12579) and incorporated by reference herein).
10.24*	Form of Restricted Stock Agreement under OGE Energy's 2013 Stock Incentive Plan. (Filed as Exhibit 10.36 to OGE Energy's Form 10-K for the year ended December 31, 2016 (File No. 1-12579) and incorporated by reference herein).

10.25*	OGE Energy Corp. Deferred Compensation Plan (As amended and restated effective October 1, 2016). (Filed as Exhibit 10.37 to OGE Energy's Form 10-K for the year ended December 31, 2016 (File No. 1-12579) and incorporated by reference herein).
10.26	Copy of the Settlement Agreement filed with the APSC on April 20, 2017. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed May 24, 2017 (File No. 1-12579) and incorporated by reference herein).
12.01	Calculation of Ratio of Earnings to Fixed Charges.
21.01	Subsidiaries of the Registrant.
23.01	Consent of Ernst & Young LLP.
23.02	Consent of Deloitte & Touche LLP for the Financial Statements of Enable Midstream Partners, LP.
24.01	Power of Attorney.
31.01	Certifications Pursuant to Rule 13a-14(a)/15d-14(a) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Description of Capital Stock. (Filed as Exhibit 99.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12579) and incorporated by reference herein).
99.02	Financial Statements of Enable Midstream Partners, LP as of and for the three years ended December 31, 2017.
99.03	Financial Statements of Enable Midstream Partners, LP as of and for the three years ended December 31, 2013 (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed November 12, 2014 (File No. 1-12579) and incorporated by reference herein).
99.04	Copy of the Report of Administrative Law Judge dated June 8, 2015. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed June 12, 2015 (File No. 1-12579) and incorporated by reference herein).
99.05	Copy of OCC Order relating to OG&E's environmental compliance plan application (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed December 7, 2015 (File No. 1-12579) and incorporated by reference herein).
99.06	Copy of the APSC Settlement Agreement approval dated May 18, 2017. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed May 24, 2017 (File No. 1-12579) and incorporated by reference herein).
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Schema Document.
101.PRE	XBRL Taxonomy Presentation Linkbase Document.
101.LAB	XBRL Taxonomy Label Linkbase Document.
101.CAL	XBRL Taxonomy Calculation Linkbase Document.
101.DEF	XBRL Definition Linkbase Document.

* Represents executive compensation plans and arrangements.

OGE ENERGY CORP.

SCHEDULE II - Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Deductions (A)	Balance at End of Period
	(In millions)			
Balance at December 31, 2015				
Reserve for Uncollectible Accounts	$ 1.6	$ 2.4	$ 2.6	$ 1.4
Balance at December 31, 2016				
Reserve for Uncollectible Accounts	$ 1.4	$ 2.5	$ 2.4	$ 1.5
Balance at December 31, 2017				
Reserve for Uncollectible Accounts	**$ 1.5**	**$ 2.6**	**$ 2.6**	**$ 1.5**

(A) Uncollectible accounts receivable written off, net of recoveries.

Item 16. Form 10-K Summary.

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Oklahoma City, and State of Oklahoma on February 21, 2018.

OGE ENERGY CORP.
(Registrant)

By /s/ Sean Trauschke
Sean Trauschke
Chairman of the Board, President
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this Report has been signed below by the following persons on behalf of the Registrant in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Sean Trauschke		
Sean Trauschke	Principal Executive Officer and Director;	February 21, 2018
/s/ Stephen E. Merrill		
Stephen E. Merrill	Principal Financial Officer;	February 21, 2018
/s/ Scott Forbes		
Scott Forbes	Principal Accounting Officer.	February 21, 2018
Frank A. Bozich	Director;	
James H. Brandi	Director;	
Peter D. Clarke	Director;	
Luke R. Corbett	Director;	
David L. Hauser	Director;	
Kirk Humphreys	Director;	
Robert O. Lorenz	Director;	
Judy R. McReynolds	Director;	
J. Michael Sanner	Director;	
Sheila G. Talton	Director;	
/s/ Sean Trauschke		
By Sean Trauschke (attorney-in-fact)		February 21, 2018

Exhibit 10.12

OGE Energy Corp.
Director Compensation

Compensation of non-officer directors of the Company in 2017 included an annual retainer fee of $210,000, of which $100,000 was payable in cash in quarterly installments and $110,000 was deposited in the director's account under the Company's Deferred Compensation Plan and converted to 3,210 common stock units based on the closing price of the Company's Common Stock on December 5, 2017. In 2017, the non-officer directors did not receive additional compensation for attending Board or committee meetings but were instead paid a quarterly cash retainer that was increased from the previous year. The lead director received an additional $25,000 cash retainer in 2017. The chair of the Audit Committee received an additional $15,000 cash retainer in 2017. The chair of the Compensation and Nominating and Corporate Governance Committees received an additional $10,000 annual cash retainer in 2017. Each member of the Audit Committee also received an additional annual retainer of $5,000. These amounts represent the total fees paid to directors in their capacities as directors of the Company and OG&E in 2017.

Under the Company's Deferred Compensation Plan, non-officer directors may defer payment of all or part of their quarterly cash retainer fee, which deferred amounts in 2017 were credited to their account as of the quarterly scheduled payment date. Amounts credited to the accounts are assumed to be invested in one or more of the investment options permitted under the Company's Deferred Compensation Plan. In 2017, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company's Common Stock. When an individual ceases to be a director of the Company, all amounts credited under the Company's Deferred Compensation Plan are paid in cash in a lump sum or installments. In certain circumstances, participants may also be entitled to in-service withdrawals from the Company's Deferred Compensation Plan.

On November 28, 2017, the Compensation Committee met to consider director compensation. At that meeting, the Compensation Committee increased the annual equity retainer, noted above, credited on December 7, 2017, from $105,000 to $110,000.

Exhibit 10.13

OGE Energy Corp.
Executive Officer Compensation

Executive Compensation

In November 2017, the Compensation Committee of the OGE Energy Corp. board of directors took actions setting executives' salaries, target amount of annual bonus awards and target amounts of long-term compensation awards for 2018. Executive compensation was set by the Compensation Committee after consideration of, among other things, individual performance and market-based data on compensation for executives with similar duties. Payouts of 2018 annual bonus targets and long-term awards are dependent on achievement of specified corporate goals established by the Compensation Committee and no officer is assured of any payout.

Salary

The Compensation Committee established the base salaries for its senior executive group. The salaries for 2018 for the OGE Energy officers who are expected to be named in the Summary Compensation Table in OGE Energy's 2018 Proxy Statement are as follows:

Executive Officer	2018 Base Salary
Sean Trauschke, Chairman, President and Chief Executive Officer	$959,500
Stephen E. Merrill, Chief Financial Officer	$466,620
E. Keith Mitchell, Chief Operating Officer of OG&E	$503,609
William H. Sultemeier, General Counsel	$425,600
Paul Renfrow, Vice President, Public Affairs and Corporate Administration (A)	$—

(A) Mr. Renfrow retired on January 1, 2018.

Establishment of 2018 Annual Incentive Awards

As stated above, at its November 2017 meeting, the Compensation Committee approved the target amount of annual incentive awards, expressed as a percentage of salary, with the officer having the ability, depending upon achievement of the 2018 corporate goals to receive from 0 percent to 150 percent of such targeted amount. For 2018, the targeted amount ranged from 60 percent to 100 percent of the approved 2018 base salary for the executive officers in the above table, excluding Mr. Renfrow, who retired on January 1, 2018.

Establishment of Long-Term Awards

At its November 2017 meeting, the Compensation Committee also approved the level of target long-term incentive awards, expressed as a percentage of salary, with the officer having the ability to receive from 0 percent to 200 percent of such targeted amount at the end of a three-year performance period depending upon achievement of the corporate goals. For 2018, the targeted amount ranged from 125 percent to 310 percent of the approved 2018 base salary for the executive officers in the above table, excluding Mr. Renfrow, who retired on January 1, 2018.

Other Benefits

Retirement Benefits. A significant amount of the Company's employees hired before December 1, 2009, including executive officers, are eligible to participate in the Company's Pension Plan and certain employees are eligible to participate in the Company's Restoration of Retirement Income Plan that enables participants, including executive officers, to receive the same benefits that they would have received under the Company's Pension Plan in the absence of limitations imposed by the Federal tax laws. In addition, the supplemental executive retirement plan, which was adopted in 1993, provides a supplemental executive retirement plan in order to attract and retain executives designated by the Compensation Committee of the Company's Board of Directors who may not otherwise qualify for a sufficient level of benefits under the Company's Pension Plan and Restoration of Retirement Income Plan. As of December 31, 2015, there are no employees participating in the supplemental executive retirement plan.

Almost all employees of the Company, including executive officers, also are eligible to participate in our 401(k) Plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as

defined in the 401(k) Plan, for that pay period. Participants who have attained age 50 before the close of a year are allowed to make additional contributions referred to as "Catch-Up Contributions," subject to certain limitations of the Code. Participants may designate, at their discretion, all or any portion of their contributions as: (i) a before-tax contribution under Section 401(k) of the Code subject to the limitations thereof; (ii) a contribution made on a non Roth after-tax basis; or (iii) a Roth contribution. The 401(k) Plan also includes an eligible automatic contribution arrangement and provides for a qualified default investment alternative consistent with the U.S. Department of Labor regulations. Participants may elect, in accordance with the 401(k) Plan procedures, to have his or her future salary deferral rate to be automatically increased annually on a date and in an amount as specified by the participant in such election. For employees hired or rehired on or after December 1, 2009, the Company contributes to the 401(k) Plan, on behalf of each participant, 200 percent of the participant's contributions up to five percent of compensation.

No Company contributions are made with respect to a participant's Catch-Up Contributions, rollover contributions, or with respect to a participant's contributions based on overtime payments, pay-in-lieu of overtime for exempt personnel, special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. Once made, the Company's contribution may be directed to any available investment option in the 401(k) Plan. The Company match contributions vest over a three-year period. After two years of service, participants become 20 percent vested in their Company contribution account and become fully vested on completing three years of service. In addition, participants fully vest when they are eligible for normal or early retirement under the Pension Plan, in the event of their termination due to death or permanent disability or upon attainment of age 65 while employed by the Company or its affiliates.

The Company provides a nonqualified deferred compensation plan which is intended to be an unfunded plan. The plan's primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of the Company and to supplement such employees' 401(k) Plan contributions as well as offering this plan to be competitive in the marketplace. Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70 percent of base salary and 100 percent of annual bonus awards or (ii) eligible employees may elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the 401(k) Plan with such deferrals to start when maximum deferrals to the qualified 401(k) Plan have been made because of limitations in that plan. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors' meeting fees and annual retainers.

The Company matches employee (but not non-employee director) deferrals to make up for any match lost in the 401(k) Plan because of deferrals to the deferred compensation plan, and to allow for a match that would have been made under the 401(k) Plan on that portion of either the first six percent of total compensation or the first five percent of total compensation, depending on prior participant elections, deferred that exceeds the limits allowed in the 401(k) Plan. Matching credits vest based on years of service, with full vesting after three years or, if earlier, on retirement, disability, death, a change in control of the Company or termination of the plan.

Deferrals, plus any Company match, are credited to a recordkeeping account in the participant's name. Earnings on the deferrals are indexed to the assumed investment funds selected by the participant. In 2017, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company's Common Stock.

Normally, payments under the deferred compensation plan begin within one year after retirement. For these purposes, normal retirement age is 65 and the minimum age to qualify for early retirement is age 55 with at least five years of service. Benefits will be paid, at the election of the participant, either in a lump sum or a stream of annual payments for up to 15 years, or a combination thereof. Participants whose employment terminates before they qualify for retirement will receive their vested account balance in one lump sum following termination as provided in the plan. Participants also will be entitled to pre- and post-retirement survivor benefits. If the participant dies while in employment before retirement, his or her beneficiary will receive a payment of the account balance plus a supplemental survivor benefit equal to two times the total amount of base salary and bonuses deferred under the plan. If the participant dies following retirement, his or her beneficiary will continue to receive the remaining vested account balance. Additionally, eligible surviving spouses will be entitled to a lifetime survivor annuity payable annually. The amount of the annuity is based on 50 percent of the participant's account balance at retirement, the spouse's age and actuarial assumptions established by the Company's Plan Administration Committee.

At any time prior to retirement, a participant may withdraw all or part of amounts attributable to his or her vested account balance under the deferred compensation plan at December 31, 2004, subject to a penalty of 10 percent of the amount withdrawn. In addition, at the time of the initial deferral election, a participant may elect to receive one or more in-service distributions on specified dates without penalty. Hardship withdrawals, without penalty, of amounts attributable to a participant's vested account balance may also be permitted at the discretion of the Company's Plan Administration Committee.

Perquisites. The Company also offers executive officers a limited amount of perquisites. These include payment of social membership dues at dining and country clubs for certain executive officers, an annual physical exam for all executive officers, a relocation program and in some instances the use of a company car. In reviewing the perquisites and the benefits under the 401(k) Plan, Deferred Compensation Plan, Pension Plan and Restoration of Retirement Income Plan, the Compensation Committee seeks to provide participants with benefits at least commensurate with those offered by other utilities of comparable size.

Change-of-Control Provisions and Employment Agreements. None of the Company's executive officers has an employment agreement with the Company. Each of the executive officers has a change of control agreement that becomes effective upon a change of control. If an executive officer's employment is terminated by the Company "without cause" following a change of control, the executive officer is entitled to the following payments: (i) all accrued and unpaid compensation and a prorated annual bonus and (ii) a severance payment equal to 2.99 times the sum of such officer's (a) annual base salary and (b) highest recent annual bonus. The change of control agreements are considered to be double trigger agreements because payment will only be made following a change of control and termination of employment. The 2.99 times multiple for change-of-control payments was selected because at the time it was considered standard. Although many companies also include provisions for tax gross-up payments to cover any excise taxes on excess parachute payments, the Company's Board of Directors decided not to include this additional benefit in the Company's agreements. Instead, under the Company's agreements if the excise tax would be imposed, the change-of-control payments will be reduced to a point where no excise tax would be payable, if such reduction would result in a greater after-tax payment.

In addition, pursuant to the terms of the Company's incentive compensation plans, upon a change of control, all stock options and restricted stock will vest immediately and, for a 60-day period following the change of control, executive officers may surrender their options and receive in return a cash payment equal to the excess of the change of control price (as defined) over the exercise price; all performance units will vest and be paid out immediately in cash as if the applicable performance goals had been satisfied at target levels; and any annual incentive award outstanding for the year in which the participant's termination occurs for any reason, other than cause, within 24 months after the change of control will be paid in cash at target level on a prorated basis.

Exhibit 12.01

OGE Energy Corp.
Ratio of Earnings to Fixed Charges

Year Ended December 31 *(In millions)*	**2017**	2016	2015	2014	2013
Earnings:					
Pre-tax income (A)	**$ 438.5**	$ 384.5	$ 353.2	$ 396.0	$ 422.2
Add: Fixed charges	**164.0**	152.0	156.3	153.9	157.2
Distributions received from equity method investment	**141.2**	141.2	139.3	143.7	51.7
Subtotal	**743.7**	677.7	648.8	693.6	631.1
Subtract:					
Allowance for borrowed funds used during construction	**18.0**	7.5	4.2	2.4	3.4
Other capitalized interest	**—**	—	—	—	2.0
Total earnings	**725.7**	670.2	644.6	691.2	625.7
Fixed Charges:					
Interest on long-term debt	**153.6**	143.2	147.8	144.6	147.6
Interest on short-term debt and other interest charges	**8.2**	6.4	5.4	6.2	5.3
Calculated interest on leased property	**2.2**	2.4	3.1	3.1	4.3
Total fixed charges	**$ 164.0**	$ 152.0	$ 156.3	$ 153.9	$ 157.2
Ratio of Earnings to Fixed Charges	**4.42**	4.41	4.12	4.49	3.98

(A) Excludes amounts attributable to income or loss from equity method investment.

Exhibit 21.01

OGE Energy Corp.
Subsidiaries of the Registrant

Name of Subsidiary	Jurisdiction of Incorporation	Percentage of Ownership
Oklahoma Gas and Electric Company	Oklahoma	100.0
OGE Enogex Holdings LLC	Delaware	100.0

The above listed subsidiaries have been consolidated in the Registrant's financial statements. Certain of the Company's subsidiaries have been omitted from the list above in accordance with Rule 1-02(w) of Regulation S-X.

Exhibit 23.01

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statement (Form S-8 No. 333-92423) pertaining to the deferred compensation plan, the Registration Statement (Form S-8 No. 333-104497) pertaining to the employees' stock ownership and retirement savings plan, Registration Statement (Form S-8 No. 333-190406) pertaining to the employees' stock ownership and retirement savings plan, Registration Statement (Form S-8 No. 333-190405) pertaining to the 2013 stock incentive plan, the Registration Statement (Form S-3ASR No. 333-221303) pertaining to the dividend reinvestment and stock purchase plan and the Registration Statement (Form S-3ASR No. 333-213005) pertaining to common stock and debt securities of our reports dated February 21, 2018, with respect to the consolidated financial statements and schedule of OGE Energy Corp., and the effectiveness of internal control over financial reporting of OGE Energy Corp., included in this Annual Report (Form 10-K) for the year ended December 31, 2017.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
February 21, 2018

Exhibit 23.02

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-92423, 333-104497, 333-190406, and 333-190405 on Form S-8; Registration Statement Nos. 333-213005 and 333-221303 on Form S-3ASR of our report dated February 20, 2018 relating to the consolidated financial statements of Enable Midstream Partners, LP and subsidiaries appearing in this Annual Report on Form 10-K of OGE Energy Corp. for the year ended December 31, 2017.

/s/ Deloitte & Touche LLP

Houston, Texas
February 21, 2018

Exhibit 24.01

Power of Attorney

WHEREAS, OGE ENERGY CORP., an Oklahoma corporation (herein referred to as the "Company"), is about to file with the Securities and Exchange Commission, under the provisions of the Securities Exchange Act of 1934, as amended, its annual report on Form 10-K for the year ended December 31, 2017; and

WHEREAS, each of the undersigned holds the office or offices in the Company herein-below set opposite his or her name, respectively;

NOW, THEREFORE, each of the undersigned hereby constitutes and appoints SEAN TRAUSCHKE, STEPHEN E. MERRILL and SCOTT FORBES and each of them individually, his or her attorney with full power to act for him or her and in his or her name, place and stead, to sign his name in the capacity or capacities set forth below to said Form 10-K and to any and all amendments thereto, and hereby ratifies and confirms all that said attorney may or shall lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have hereunto set their hands this 21st day of February, 2018.

Sean Trauschke, Chairman, Principal Executive Officer and Director	/s/ Sean Trauschke
Frank A. Bozich, Director	/s/ Frank A. Bozich
James H. Brandi, Director	/s/ James H. Brandi
Peter D. Clarke, Director	/s/ Peter D. Clarke
Luke R. Corbett, Director	/s/ Luke R. Corbett
David L. Hauser, Director	/s/ David L. Hauser
Kirk Humphreys, Director	/s/ Kirk Humphreys
Robert O. Lorenz, Director	/s/ Robert O. Lorenz
Judy R. McReynolds, Director	/s/ Judy R. McReynolds
J. Michael Sanner, Director	/s/ J. Michael Sanner
Sheila G. Talton, Director	/s/ Sheila G. Talton
Stephen E. Merrill, Principal Financial Officer	/s/ Stephen E. Merrill
Scott Forbes, Principal Accounting Officer	/s/ Scott Forbes

STATE OF OKLAHOMA)
) SS
COUNTY OF OKLAHOMA)

On the date indicated above, before me, Kelly Hamilton-Coyer, Notary Public in and for said County and State, the above named directors and officers of OGE ENERGY CORP., an Oklahoma corporation, known to me to be the persons whose names are subscribed to the foregoing instrument, severally acknowledged to me that they executed the same as their own free act and deed.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal on the 21st day of February, 2018.

/s/ Kelly Hamilton-Coyer
By: Kelly Hamilton-Coyer
Notary Public

My commission expires:
July 6, 2021

Exhibit 31.01

CERTIFICATIONS

I, Sean Trauschke, certify that:

1. I have reviewed this annual report on Form 10-K of OGE Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2018

/s/ Sean Trauschke

Sean Trauschke

Chairman of the Board, President and Chief Executive Officer

Exhibit 31.01

CERTIFICATIONS

I, Stephen E. Merrill, certify that:

1. I have reviewed this annual report on Form 10-K of OGE Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2018

/s/ Stephen E. Merrill

Stephen E. Merrill

Chief Financial Officer

Exhibit 32.01

Certification Pursuant to 18 U.S.C. Section 1350
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of the Company on Form 10-K for the period ended December 31, 2017, as filed with the Securities and Exchange Commission (the "Report"), each of the undersigned does hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 21, 2018

/s/ Sean Trauschke

Sean Trauschke
Chairman of the Board, President and Chief Executive Officer

/s/ Stephen E. Merrill

Stephen E. Merrill
Chief Financial Officer

Exhibit 99.02

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enable GP, LLC and
Unitholders of Enable Midstream Partners, LP
Oklahoma City, Oklahoma

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Enable Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2017 and 2016, the related consolidated statements of income, cash flows, and partners' equity for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 20, 2018, expressed an unqualified opinion on the Partnership's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 20, 2018
We have served as the Partnership's auditor since 2013.

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2017	2016	2015
	(In millions, except per unit data)		
Revenues (including revenues from affiliates (Note 14)):			
Product sales	$ 1,653	$ 1,172	$ 1,334
Service revenue	1,150	1,100	1,084
Total Revenues	2,803	2,272	2,418
Cost and Expenses (including expenses from affiliates (Note 14)):			
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	1,381	1,017	1,097
Operation and maintenance	369	367	419
General and administrative	95	98	103
Depreciation and amortization	366	338	318
Impairments (Note 8, Note 12)	—	9	1,134
Taxes other than income taxes	64	58	59
Total Cost and Expenses	2,275	1,887	3,130
Operating Income (Loss)	528	385	(712)
Other Income (Expense):			
Interest expense (including expenses from affiliates (Note 14))	(120)	(99)	(90)
Equity in earnings of equity method affiliate	28	28	29
Other, net	—	—	2
Total Other Income (Expense)	(92)	(71)	(59)
Income (Loss) Before Income Taxes	436	314	(771)
Income tax expense (benefit)	(1)	1	—
Net Income (Loss)	$ 437	$ 313	$ (771)
Less: Net income (loss) attributable to noncontrolling interest	1	1	(19)
Net Income (Loss) Attributable to Limited Partners	$ 436	$ 312	$ (752)
Less: Series A Preferred Unit distributions (Note 5)	36	22	—
Net Income (Loss) Attributable to Common and Subordinated Units (Note 4)	$ 400	$ 290	$ (752)
Basic earnings (loss) per unit (Note 4)			
Common units	$ 0.92	$ 0.69	$ (1.78)
Subordinated units	$ 0.93	$ 0.68	$ (1.78)
Diluted earnings (loss) per unit (Note 4)			
Common units	$ 0.92	$ 0.69	$ (1.78)
Subordinated units	$ 0.93	$ 0.68	$ (1.78)

See Notes to the Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2017	2016
	(In millions, except units)	
Current Assets:		
Cash and cash equivalents	$ 5	$ 6
Restricted cash	14	17
Accounts receivable, net	277	249
Accounts receivable—affiliated companies	18	13
Inventory	40	41
Gas imbalances	37	41
Other current assets	25	29
Total current assets	416	396
Property, Plant and Equipment:		
Property, plant and equipment	12,079	11,567
Less accumulated depreciation and amortization	1,724	1,424
Property, plant and equipment, net	10,355	10,143
Other Assets:		
Intangible assets, net	451	306
Goodwill	12	—
Investment in equity method affiliate	324	329
Other	35	38
Total other assets	822	673
Total Assets	$ 11,593	$ 11,212
Current Liabilities:		
Accounts payable	$ 263	$ 181
Accounts payable—affiliated companies	3	3
Short-term debt	405	—
Current portion of long-term debt	450	—
Taxes accrued	32	30
Gas imbalances	12	35
Accrued compensation	32	37
Customer deposits	34	31
Other	48	45
Total current liabilities	1,279	362
Other Liabilities:		
Accumulated deferred income taxes, net	6	10
Regulatory liabilities	21	19
Other	38	34
Total other liabilities	65	63
Long-Term Debt	2,595	2,993
Commitments and Contingencies (Note 15)		
Partners' Equity:		
Series A Preferred Units (14,520,000 issued and outstanding at December 31, 2017 and December 31, 2016, respectively)	362	362
Common units (432,584,080 issued and outstanding at December 31, 2017 and 224,535,454 issued and outstanding at December 31, 2016, respectively)	7,280	3,737
Subordinated units (0 issued and outstanding at December 31, 2017 and 207,855,430 issued and outstanding at December 31, 2016, respectively)	—	3,683
Noncontrolling interest	12	12
Total Partners' Equity	7,654	7,794
Total Liabilities and Partners' Equity	$ 11,593	$ 11,212

See Notes to the Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
Cash Flows from Operating Activities:			
Net income (loss)	$ 437	$ 313	$ (771)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	366	338	318
Deferred income taxes	(3)	2	(1)
Impairments	—	9	1,134
Loss on sale/retirement of assets	7	17	5
Equity in earnings of equity method affiliate	(28)	(28)	(29)
Return on investment of equity method affiliate	28	28	34
Equity-based compensation	15	13	9
Amortization of debt costs and discount (premium)	(2)	(3)	(2)
Changes in other assets and liabilities:			
Accounts receivable, net	(23)	(4)	9
Accounts receivable—affiliated companies	(5)	8	6
Inventory	1	12	10
Gas imbalance assets	4	(18)	22
Other current assets	4	6	2
Other assets	1	(1)	(4)
Accounts payable	54	(34)	—
Accounts payable—affiliated companies	—	(6)	(29)
Gas imbalance liabilities	(23)	10	12
Other current liabilities	(4)	45	6
Other liabilities	5	14	(5)
Net cash provided by operating activities	834	721	726
Cash Flows from Investing Activities:			
Capital expenditures	(416)	(383)	(869)
Acquisitions, net of cash acquired	(298)	—	(80)
Proceeds from sale of assets	1	1	3
Proceeds from insurance	2	—	—
Return of investment in equity method affiliate	5	15	8
Investment in equity method affiliate	—	—	(8)
Net cash used in investing activities	(706)	(367)	(946)
Cash Flows from Financing Activities:			
Proceeds from long-term debt, net of issuance costs	691	—	450
Proceeds from revolving credit facility	1,200	1,734	585
Repayment of revolving credit facility	(1,836)	(1,408)	(275)
Increase (decrease) in short-term debt	405	(236)	(17)
Repayment of notes payable—affiliated companies	—	(363)	—
Proceeds from issuance of common units	—	137	—
Proceeds from issuance of Series A Preferred Units, net of issuance costs	—	362	—
Distributions	(590)	(561)	(531)
Cash taxes paid for employee equity-based compensation	(2)	—	—
Net cash provided by (used in) financing activities	(132)	(335)	212
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(4)	19	(8)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	23	4	12
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 19	$ 23	$ 4

See Notes to the Consolidated Financial Statements

Exhibit 99.02

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY

	Series A Preferred Units		Common Units		Subordinated Units		Noncontrolling Interest	Total Partners' Equity
	Units	Value	Units	Value	Units	Value	Value	Value
				(In millions)				
Balance as of December 31, 2014	—	$ —	214	$ 4,353	208	$ 4,439	$ 31	$ 8,823
Net loss	—	—	—	(379)	—	(373)	(19)	(771)
Issuance of common units upon interest acquisition of SESH	—	—	—	1	—	—	—	1
Distributions	—	—	—	(270)	—	(261)	—	(531)
Equity-based compensation, net of units for employee taxes	—	—	—	9	—	—	—	9
Balance as of December 31, 2015	—	$ —	214	$ 3,714	208	$ 3,805	$ 12	$ 7,531
Net income	—	22	—	147	—	143	1	313
Issuance of Series A Preferred Units	15	362	—	—	—	—	—	362
Issuance of common units	—	—	10	137	—	—	—	137
Distributions	—	(22)	—	(274)	—	(265)	(1)	(562)
Equity-based compensation, net of units for employee taxes	—	—	—	13	—	—	—	13
Balance as of December 31, 2016	15	$ 362	224	$ 3,737	208	$ 3,683	$ 12	$ 7,794
Net income	—	36	—	266	—	134	1	437
Conversion of subordinated units	—	—	208	3,619	(208)	(3,619)	—	—
Distributions	—	(36)	—	(355)	—	(198)	(1)	(590)
Equity-based compensation, net of units for employee taxes	—	—	1	13	—	—	—	13
Balance as of December 31, 2017	15	$ 362	433	$ 7,280	—	$ —	$ 12	$ 7,654

See Notes to the Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Organization

Enable Midstream Partners, LP (Partnership) is a Delaware limited partnership formed on May 1, 2013 by CenterPoint Energy, OGE Energy and ArcLight, pursuant to the terms of the MFA. The Partnership's assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage. The gathering and processing segment primarily provides natural gas and crude oil gathering and natural gas processing services to our producer customers. The transportation and storage segment provides interstate and intrastate natural gas pipeline transportation and storage services primarily to our producer, power plant, LDC and industrial end-user customers. The Partnership's natural gas gathering and processing assets are primarily located in Oklahoma, Texas, Arkansas and Louisiana and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex Basins. Crude oil gathering assets are located in North Dakota and serve crude oil production in the Bakken Shale formation of the Williston Basin. The Partnership's natural gas transportation and storage assets consist primarily of an interstate pipeline system extending from western Oklahoma and the Texas Panhandle to Louisiana, an interstate pipeline system extending from Louisiana to Illinois, an intrastate pipeline system in Oklahoma, and our investment in SESH, a pipeline extending from Louisiana to Alabama.

CenterPoint Energy and OGE Energy each have 50% of the management interests in Enable GP. Enable GP is the general partner of the Partnership and has no other operating activities. Enable GP is governed by a board made up of two representatives designated by each of CenterPoint Energy and OGE Energy, along with the Partnership's Chief Executive Officer and three independent board members CenterPoint Energy and OGE Energy mutually agreed to appoint. CenterPoint Energy and OGE Energy also own a 40% and 60% interest, respectively, in the incentive distribution rights held by Enable GP.

At December 31, 2017, CenterPoint Energy held approximately 54.1% or 233,856,623 of the Partnership's common units, and OGE Energy held approximately 25.7% or 110,982,805 of the Partnership's common units. Additionally, CenterPoint Energy holds 14,520,000 Series A Preferred Units. See Note 5 for further information related to the Series A Preferred Units. The limited partner interests of the Partnership have limited voting rights on matters affecting the business. As such, limited partners do not have rights to elect the Partnership's General Partner (Enable GP) on an annual or continuing basis and may not remove Enable GP without at least a 75% vote by all unitholders, including all units held by the Partnership's limited partners, and Enable GP and its affiliates, voting together as a single class.

For the period from December 31, 2014 through June 29, 2015, the financial statements reflect a 49.90% interest in SESH. On June 12, 2015, CenterPoint Energy exercised its put right with respect to a 0.1% interest in SESH. Pursuant to the put right, on June 30, 2015, CenterPoint Energy contributed its remaining 0.1% interest in SESH to the Partnership in exchange for 25,341 common units. For the years ended December 31, 2017 and 2016, the Partnership owned a 50% interest in SESH. See Note 9 for further discussion of SESH.

In addition, for the years ended December 31, 2017, 2016 and 2015, the Partnership held a 50% ownership interest in Atoka and consolidated Atoka in its Consolidated Financial Statements as EOIT acted as the managing member of Atoka and had control over the operations of Atoka.

Basis of Presentation

The accompanying consolidated financial statements and related notes of the Partnership have been prepared pursuant to the rules and regulations of the SEC and GAAP.

For a description of the Partnership's reportable segments, see Note 18.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue Recognition

The Partnership generates the majority of its revenues from midstream energy services, including natural gas gathering, processing, transportation and storage and crude oil gathering. The Partnership performs these services under various contractual arrangements, which include fee-based contract arrangements and arrangements pursuant to which it purchases and resells commodities in connection with providing the related service and earns a net margin for its fee. The Partnership reflects revenue as Product sales and Service revenue on the Consolidated Statements of Income as follows:

Product sales: Product sales represent the sale of natural gas, NGLs, crude oil and condensate where the product is purchased and used in connection with providing the Partnership's midstream services.

Service revenue: Service revenue represents all other revenue generated as a result of performing the Partnership's midstream services.

Revenues for gathering, processing, transportation and storage services for the Partnership are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Revenues associated with the production of NGLs are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated revenues are reflected in Accounts receivable, net or Accounts receivable—affiliated companies, as appropriate, on the Consolidated Balance Sheets and in Revenues on the Consolidated Statements of Income.

The Partnership recognizes revenue from natural gas gathering, processing, transportation and storage and crude oil gathering services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold. The Partnership records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. The Partnership had $35 million and $34 million of deferred revenues, including deferred revenue—affiliated companies, included in Other current liabilities and Other long-term liabilities on the Consolidated Balance Sheets at December 31, 2017 and 2016, respectively.

The Partnership relies on certain key natural gas producer customers for a significant portion of natural gas and NGLs supply. The Partnership relies on certain key utilities for a significant portion of transportation and storage demand. The Partnership depends on third-party facilities to transport and fractionate NGLs that it delivers to third parties at the inlet of their facilities. Additionally, for the years ended December 31, 2017, 2016 and 2015, one third party purchased approximately 13%, 22% and 18%, respectively, of the NGLs delivered off our system, which accounted for approximately $140 million, $129 million and $108 million, or 5%, 6% and 4%, respectively, of total revenues. Additionally, in the year ended December 31, 2017, another third party purchased 12% of the NGLs delivered off our system, which accounted for $127 million, or 4% of total revenues. Other than revenues from affiliates discussed in Note 14, there are no other revenue concentrations with individual customers in the years ended December 31, 2017, 2016 and 2015.

Natural Gas and Natural Gas Liquids Purchases

Cost of natural gas and natural gas liquids represents cost of our natural gas and natural gas liquids purchased exclusive of depreciation, Operation and maintenance and General and administrative expenses and consists primarily of product and fuel costs. Estimates for gas purchases are based on estimated volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable or Accounts Payable-affiliated companies, as appropriate, on the Consolidated Balance Sheets and in Cost of natural gas and natural gas liquids, excluding Depreciation and amortization on the Consolidated Statements of Income.

Operation and Maintenance and General and Administrative Expense

Operation and maintenance expense represents the cost of our service related revenues and consists primarily of labor expenses, lease costs, utility costs, insurance premiums and repairs and maintenance expenses directly related with the operations of assets. General and administrative expense represents cost incurred to manage the business. This expense includes cost of general corporate services, such as treasury, accounting, legal, information technology and human resources and all other expenses necessary or appropriate to the conduct of business. Any Operation and maintenance expense and General and administrative expense associated with product sales is immaterial.

Environmental Costs

The Partnership expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. The Partnership expenses amounts that relate to an existing condition caused by past operations that do not have future economic benefit. The Partnership records undiscounted liabilities related to these future costs when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated. There are no material amounts accrued at December 31, 2017 or 2016.

Depreciation and Amortization Expense

Depreciation is computed using the straight-line method based on economic lives or a regulatory-mandated recovery period. Amortization of intangible assets is computed using the straight-line method over the respective lives of the intangible assets.

The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets at the time the assets are placed in service. As circumstances warrant, useful lives are adjusted when changes in planned use, changes in estimated production lives of affiliated natural gas basins or other factors indicate that a different life would be more appropriate. Such changes could materially impact future depreciation expense. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively. The computation of amortization expense on intangible assets requires judgment regarding the amortization method used. Intangible assets are amortized on a straight-line basis over their useful lives using a method of amortization that reflects the pattern in which the economic benefits of the intangible asset are consumed.

Income Taxes

The Partnership's earnings are not subject to income tax (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiaries, Enable Midstream Services and Enable Muskogee Intrastate Transmission) and are taxable at the individual partner level. For more information, see Note 16.

We account for deferred income taxes related to the federal and state jurisdictions using the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the future taxes attributable to the difference between financial statement carrying amounts of assets and liabilities and their respective tax basis. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of tax net operating loss carryforwards. In the event future utilization is determined to be unlikely, a valuation allowance is provided to reduce the tax benefits from such assets. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the period in which the temporary differences and carryforwards are expected to be recovered or settled. The effect of a change in tax rates is recognized in the period which includes the enactment date. The Partnership recognizes interest and penalties as a component of income tax expense.

Cash and Cash Equivalents

The Partnership considers cash equivalents to be short-term, highly liquid investments with maturities of three months or less from the date of purchase. The Consolidated Balance Sheets have $5 million and $6 million of cash and cash equivalents as of December 31, 2017 and 2016, respectively.

Restricted Cash

Restricted cash consists of cash which is restricted by agreements with third parties. The Consolidated Balance Sheets have $14 million and $17 million of restricted cash as of December 31, 2017 and 2016, respectively.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not typically bear interest. The determination of the allowance for doubtful accounts requires management to make estimates and judgments regarding our customers' ability to pay. The allowance for doubtful accounts is determined based upon specific identification and estimates of future uncollectable amounts. On an ongoing basis, we evaluate our customers' financial strength based on aging of accounts receivable, payment history and review of other relevant information, including ratings agency credit ratings and alerts, publicly available reports and news releases, and bank and trade references. It is the policy of management to review the outstanding accounts receivable at least quarterly, giving consideration to historical bad debt write-offs, the aging of receivables and specific customer circumstances that may impact their ability to pay the amounts due. Based on this review, management determined that a $3 million allowance for doubtful accounts was required at each of December 31, 2017 and 2016.

Inventory

Materials and supplies inventory is valued at cost and is subsequently recorded at the lower of cost or net realizable value. The Partnership recorded write-downs to net realizable value related to materials and supplies inventory disposed or identified as excess or obsolete of $1 million for each of the years ended December 31, 2017 and 2016. There were less than $1 million of write-downs related to materials and supplies inventory for the year ended December 31, 2015. Materials and supplies are recorded to inventory when purchased and, as appropriate, subsequently charged to operation and maintenance expense on the Consolidated Statements of Income or capitalized to property, plant and equipment on the Consolidated Balance Sheets when installed.

Natural gas inventory is held, through the transportation and storage segment, to provide operational support for the intrastate pipeline deliveries and to manage leased intrastate storage capacity. Natural gas liquids inventory is held, through the gathering and processing segment, due to timing differences between the production of certain natural gas liquids and ultimate sale to third parties. Natural gas and natural gas liquids inventory is valued using moving average cost and is subsequently recorded at the lower of cost or net realizable value. During the years ended December 31, 2017, 2016 and 2015, the Partnership recorded write-downs to net realizable value related to natural gas and natural gas liquids inventory of $2 million, $3 million and $13 million, respectively. The cost of gas associated with sales of natural gas and natural gas liquids inventory is presented in Cost of natural gas and natural gas liquids, excluding depreciation and amortization on the Consolidated Statements of Income.

	December 31,	
	2017	2016
	(In millions)	
Materials and supplies	$ 29	$ 30
Natural gas and natural gas liquids inventories	11	11
Total	$ 40	$ 41

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by the Partnership's pipeline systems differ from the amounts scheduled to be delivered or received. Imbalances are due to or due from shippers and operators and can be settled in cash or natural gas depending on contractual terms. The Partnership values all imbalances at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value.

Long-Lived Assets (including Intangible Assets)

The Partnership records property, plant and equipment and intangible assets at historical cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and capitalized interest. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and charged to Accumulated depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance net of any salvage proceeds is recorded as a loss in the Consolidated Statements of Income as Operation and maintenance expense. The Partnership expenses repair and maintenance costs as incurred. Repair, removal and maintenance costs are included in the Consolidated Statements of Income as Operation and maintenance expense.

Assessing Impairment of Long-lived Assets (including Intangible Assets) and Goodwill

The Partnership periodically evaluates long-lived assets, including property, plant and equipment, and specifically identifiable intangibles other than goodwill, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. For more information, see Note 12.

The Partnership assesses its goodwill for impairment annually on October 1st, or more frequently if events or changes in circumstances indicate that the carrying value of goodwill may not be recoverable. Goodwill is assessed for impairment by comparing the fair value of the reporting unit with its book value, including goodwill. The Partnership utilizes the market or income approaches to estimate the fair value of the reporting unit, also giving consideration to the alternative cost approach. Under the market approach, historical and current year forecasted cash flows are multiplied by a market multiple to determine fair value. Under the income approach, anticipated cash flows over a period of years plus a terminal value are discounted to present value

using appropriate discount rates. If the estimated fair value of the reporting unit is less than the carrying amount of the reporting unit, then a second step must be completed in order to determine the amount of the goodwill impairment that should be recorded. In the second step, the implied fair value of the reporting unit's goodwill is determined by allocating the reporting unit's fair value to all of its assets and liabilities other than goodwill (including any unrecognized intangible assets) in a manner similar to a purchase price allocation. The resulting implied fair value of the goodwill that results from the application of this second step is then compared to the carrying amount of the goodwill and an impairment charge is recorded for the difference. The Partnership performs its goodwill impairment testing at the transportation and storage and gathering and processing reportable segment level. For more information, see Note 8.

Regulatory Assets and Liabilities

The Partnership applies the guidance for accounting for regulated operations to portions of the transportation and storage segment. The Partnership's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of each of December 31, 2017 and 2016, these removal costs of $21 million and $19 million, respectively, are classified as Regulatory liabilities in the Consolidated Balance Sheets.

Capitalization of Interest and Allowance for Funds Used During Construction

Allowance for funds used during construction (AFUDC) represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases both utility plant and earnings, it is realized in cash when the assets are included in rates for entities that apply guidance for accounting for regulated operations. Capitalized interest represents the approximate net composite interest cost of borrowed funds used for construction. Interest and AFUDC are capitalized as a component of projects under construction and will be amortized over the assets' estimated useful lives. During the years ended December 31, 2017, 2016 and 2015, the Partnership capitalized interest and AFUDC of $1 million, $4 million and $10 million, respectively.

Derivative Instruments

The Partnership is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. At times, the Partnership utilizes derivative instruments such as physical forward contracts, financial futures and swaps to mitigate the impact of changes in commodity prices on its operating results and cash flows. Such derivatives are recognized in the Partnership's Consolidated Balance Sheets at their fair value unless the Partnership elects hedge accounting or the normal purchase and sales exemption for qualified physical transactions. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized in Product sales in the Consolidated Statements of Income. A derivative may be designated as a normal purchase or normal sale if the intent is to physically receive or deliver the product for use or sale in the normal course of business.

The Partnership's policies prohibit the use of leveraged financial instruments. A leveraged financial instrument, for this purpose, is a transaction involving a derivative whose financial impact will be based on an amount other than the notional amount or volume of the instrument.

Fair Value Measurements

The Partnership determines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. As required, the Partnership utilizes valuation techniques that maximize the use of observable inputs (levels 1 and 2) and minimize the use of unobservable inputs (level 3) within the fair value hierarchy included in current accounting guidance. The Partnership generally applies the market approach to determine fair value. This method uses pricing and other information generated by market transactions for identical or comparable assets and liabilities. Assets and liabilities are classified within the fair value hierarchy based on the lowest level (least observable) input that is significant to the measurement in its entirety.

Equity-Based Compensation

The Partnership awards equity-based compensation to officers, directors and employees under the Long-Term Incentive Plan. All equity-based awards to officers, directors and employees under the Long-Term Incentive Plan, including grants of performance units, time-based phantom units (phantom units) and time-based restricted units (restricted units) are recognized in the Consolidated Statements of Income based on their fair values. The fair value of the phantom units and restricted units are based on the closing market price of the Partnership's common unit on the grant date. The fair value of the performance units is

estimated on the grant date using a lattice-based valuation model that factors in information, including the expected distribution yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the phantom unit and restricted unit awards is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a vesting period. The vesting of the performance unit awards is also contingent upon the probable outcome of the market condition. Depending on forfeitures and actual vesting, the compensation expense recognized related to the awards could increase or decrease.

Fifth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP

On November 14, 2017, the General Partner adopted the Fifth Amended and Restated Agreement of Limited Partnership (the Partnership Agreement), to implement certain changes to the Internal Revenue Code enacted by the Bipartisan Budget Act of 2015 relating to partnership audit and adjustment procedures. The Partnership Agreement also removed references to the subordinated units (all of which previously converted into common units) and related provisions.

(2) New Accounting Pronouncements

Accounting Standards to be Adopted in Future Periods

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," which supersedes the revenue recognition requirements in "Revenue Recognition (Topic 605)." Topic 606 is based on the core principle that revenue is recognized to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Topic 606 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers, including significant judgments and changes in judgments and assets recognized from costs incurred to obtain or fulfill a contract.

As part of our evaluation of the impact of this standard, we have completed our review of customer contracts across all our business segments. We do not believe the adoption of Topic 606 will have a material impact on Product sales, Operating Income or Net Income. However, we have identified certain contractual arrangements that will materially impact Service revenue and Cost of natural gas and natural gas liquids upon adoption of Topic 606, as follows:

- *Natural gas and natural gas liquids purchase arrangements* - For certain arrangements within our gathering and processing segment, the Partnership purchases and controls the entire hydrocarbon stream at the point of receipt. Under Topic 606, these arrangements are considered supplier contracts rather than contracts with customers. Therefore, upon adoption of Topic 606, the gathering and processing fees for these arrangements that were previously recognized as Service revenue under Topic 605 will now be recognized as reductions to Cost of natural gas and natural gas liquids.
- *Percent-of-proceeds and percent-of-liquids processing arrangements* - Under percent-of-proceeds and percent-of-liquids arrangements within our gathering and processing segment, we have recognized the value of natural gas and natural gas liquids received in our purchase cost within Cost of natural gas and natural gas liquids. Under Topic 606, the Partnership will recognize the value of the natural gas and NGLs received as Service revenue and as an increase to Cost of natural gas and natural gas liquids when the natural gas or NGLs are sold and Product sales are recognized.
- *Keep-whole arrangements* - Under keep-whole arrangements within our gathering and processing segment, the Partnership recognized the value of NGLs received in Product revenue and the value of the thermally equivalent quantity of natural gas provided in our purchase cost within Cost of natural gas and natural gas liquids. Under Topic 606, the Partnership will recognize the value of the NGLs received less the value of the thermal equivalent volume of natural gas provided as Service revenue and as an increase to Cost of natural gas and natural gas liquids when the NGLs are sold and Product sales are recognized.
- *Fixed fuel arrangements* - Under certain gathering arrangements within our gathering and processing segment as well as under certain transportation arrangements within our transportation and storage segment we receive a fixed amount of fuel regardless of actual fuel usage. Historically, revenue for fuel in excess of actual usage was recognized when such fuel was received, and additional revenue was recognized when such fuel was sold. Under Topic 606, fuel in excess of actual usage will be treated as a byproduct obtained through the fulfillment of a contract, and the Partnership will recognize revenue at the time the excess fuel is sold. This will result in a reduction of Product sales and a corresponding reduction in Cost of natural gas and natural gas liquids.

We continue to develop the underlying reports, internal controls and disclosures to record activity under Topic 606 upon adoption. The Partnership adopted Topic 606 on January 1, 2018 using the modified retrospective method. Upon adoption, we did not recognize a material cumulative adjustment to Partners' Equity and we do not expect material changes in the timing of revenue recognition or our accounting policies.

Leases

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)." This standard requires, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the commencement date: (1) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The Partnership expects to adopt this standard in the first quarter of 2019 and is currently evaluating the impact of this standard on our Consolidated Financial Statements and related disclosures. In connection with our assessment work, we formed an implementation work team and are continuing our review of our contracts relative to the provisions of the lease standard.

Financial Instruments—Credit Losses

In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments." This standard requires entities to measure all expected credit losses of financial assets held at a reporting date based on historical experience, current conditions, and reasonable and supportable forecasts in order to record credit losses in a more timely matter. ASU 2016-13 also amends the accounting for credit losses on available-for-sale debt securities and purchased financial assets with credit deterioration. The standard is effective for interim and annual reporting periods beginning after December 15, 2019, although early adoption is permitted for interim and annual periods beginning after December 15, 2018. The Partnership does not expect the adoption of this standard to have a material impact on our Consolidated Financial Statements and related disclosures.

Income Taxes

In October 2016, the FASB issued ASU No. 2016-16, "Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory." This standard requires entities to recognize the tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs. The standard is effective for interim and annual reporting periods beginning after December 15, 2017, although early adoption is permitted as of the beginning of an annual period (i.e., only in the first interim period). The guidance requires application using a modified retrospective approach. The Partnership does not expect the adoption of this standard to have a material impact on our Consolidated Financial Statements and related disclosures.

(3) Acquisitions

Align Acquisition

On October 4, 2017, the Partnership acquired all of the equity interests in Align Midstream, LLC, a midstream service provider with natural gas gathering and processing facilities in the Cotton Valley and Haynesville plays of the Ark-La-Tex Basin, for approximately $298 million in cash. The acquisition includes approximately 190 miles of natural gas gathering pipelines across Rusk, Panola and Shelby counties in Texas and DeSoto Parish in Louisiana and a cryogenic natural gas processing plant in Panola County, Texas, with a capacity of 100 MMcf/d. The acquisition was accounted for as a business combination and funded with borrowings under the Revolving Credit Facility. During the fourth quarter of 2017, the Partnership finalized the purchase price allocation as of October 4, 2017.

The following table presents the fair value of the identified assets acquired and liabilities assumed at the acquisition date:

Purchase price allocation (in millions):		
Assets acquired:		
Accounts receivable	$	5
Property, plant and equipment		111
Intangibles		176
Goodwill		12
Liabilities assumed:		
Current liabilities		6
Total identifiable net assets	$	298

The Partnership recognized intangible assets related to customer relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated customer contract life of approximately 10 years. Goodwill recognized from the acquisition primarily relates to greater operating leverage in the Ark-La-Tex Basin and is allocated to the gathering and processing segment. The Partnership incurred approximately $2 million of acquisition costs associated with this transaction, which are included in General and administrative expense in the Consolidated Statements of Income. The Partnership determined not to include pro forma consolidated financial statements for the periods presented as the impact would not be material.

Monarch Acquisition

On April 22, 2015, the Partnership entered into an agreement with Monarch Natural Gas, LLC, pursuant to which the Partnership agreed to acquire approximately 106 miles of gathering pipeline, approximately 5,000 horsepower of associated compression, right-of-ways and certain other midstream assets that provide natural gas gathering services in the Greater Granite Wash area of Texas. The transaction closed on May 1, 2015. The aggregate purchase price for this transaction was approximately $80 million, which was funded from cash generated from operations and borrowings under our Revolving Credit Facility.

The acquisition was accounted for as a business combination. During the third quarter of 2015, the Partnership finalized the purchase price allocation as of May 1, 2015.

Purchase price allocation (in millions):		
Property, plant and equipment	$	51
Intangibles		10
Goodwill		19
Total	$	80

The Partnership recognized intangible assets related to customer relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated customer contract life of approximately 15 years. Goodwill recognized from the acquisition primarily relates to the value created from additional growth opportunities and greater operating leverage in the Anadarko Basin. See Note 8 for further information related to the Partnership's goodwill impairment. The Partnership incurred less than $1 million of acquisition costs associated with this transaction, which are included in General and administrative expense in the Consolidated Statements of Income.

(4) Earnings Per Limited Partner Unit

Basic and diluted earnings per limited partner unit is calculated by dividing net income (loss) allocable to common and subordinated unitholders by the weighted average number of common and subordinated units outstanding during the period. Any common units issued during the period are included on a weighted average basis for the days in which they were outstanding. The dilutive effect of the unit-based awards discussed in Note 17 was less than $0.01 per unit during the years ended December 31, 2017, 2016 and 2015.

The following table illustrates the Partnership's calculation of earnings (loss) per unit for common and subordinated units:

	Year Ended December 31,		
	2017	2016	2015
	(In millions, except per unit data)		
Net income (loss)	$ 437	$ 313	$ (771)
Net income (loss) attributable to noncontrolling interest	1	1	(19)
Series A Preferred Unit distributions	36	22	—
General partner interest in net income	—	—	—
Net income (loss) available to common and subordinated unitholders	$ 400	$ 290	$ (752)
Net income (loss) allocable to common units	$ 273	$ 148	$ (381)
Net income (loss) allocable to subordinated units	127	142	(371)
Net income (loss) available to common and subordinated unitholders	$ 400	$ 290	$ (752)
Net income (loss) allocable to common units	$ 273	$ 148	$ (381)
Dilutive effect of Series A Preferred Unit distribution	—	—	—
Diluted net income (loss) allocable to common units	273	148	(381)
Diluted net income (loss) allocable to subordinated units	127	142	(371)
Total	$ 400	$ 290	$ (752)
Basic weighted average number of outstanding			
Common units [1]	296	216	214
Subordinated units	137	208	208
Total	433	424	422
Basic earnings (loss) per unit			
Common units	$ 0.92	$ 0.69	$ (1.78)
Subordinated units	$ 0.93	$ 0.68	$ (1.78)
Basic weighted average number of outstanding common units	296	216	214
Dilutive effect of Series A Preferred Units	—	—	—
Dilutive effect of performance units	1	—	—
Diluted weighted average number of outstanding common units	297	216	214
Diluted weighted average number of outstanding subordinated units	137	208	208
Total	434	424	422
Diluted earnings (loss) per unit			
Common units	$ 0.92	$ 0.69	$ (1.78)
Subordinated units	$ 0.93	$ 0.68	$ (1.78)

(1) Basic weighted average number of outstanding common units for the year ended December 31, 2017 includes approximately one million time-based phantom units.

See Note 5 for discussion of the expiration of the subordination period.

(5) Enable Midstream Partners, LP Partners' Equity

The Partnership Agreement requires that, within 60 days subsequent to the end of each quarter, the Partnership distribute all of its available cash (as defined in the Partnership Agreement) to unitholders of record on the applicable record date.

The Partnership paid or has authorized payment of the following cash distributions to common and subordinated unitholders, as applicable, during 2017, 2016 and 2015 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
December 31, 2017 (1)	February 20, 2018	February 27, 2018	$ 0.318	$ 138
September 30, 2017	November 14, 2017	November 21, 2017	$ 0.318	$ 138
June 30, 2017	August 22, 2017	August 29, 2017	$ 0.318	$ 138
March 31, 2017	May 23, 2017	May 30, 2017	$ 0.318	$ 137
December 31, 2016	February 21, 2017	February 28, 2017	$ 0.318	$ 137
September 30, 2016	November 14, 2016	November 22, 2016	$ 0.318	$ 134
June 30, 2016	August 16, 2016	August 23, 2016	$ 0.318	$ 134
March 31, 2016	May 6, 2016	May 13, 2016	$ 0.318	$ 134
December 31, 2015	February 2, 2016	February 12, 2016	$ 0.318	$ 134
September 30, 2015	November 3, 2015	November 13, 2015	$ 0.318	$ 134
June 30, 2015	August 3, 2015	August 13, 2015	$ 0.316	$ 134
March 31, 2015	May 5, 2015	May 15, 2015	$ 0.3125	$ 132

(1) The board of directors of Enable GP declared this $0.318 per common unit cash distribution on February 9, 2018, to be paid on February 27, 2018, to common unitholders of record at the close of business on February 20, 2018.

The Partnership paid or has authorized payment of the following cash distributions to holders of the Series A Preferred Units during 2017 and 2016 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
December 31, 2017 (1)	February 9, 2018	February 15, 2018	$ 0.625	$ 9
September 30, 2017	October 31, 2017	November 14, 2017	$ 0.625	$ 9
June 30, 2017	July 31, 2017	August 14, 2017	$ 0.625	$ 9
March 31, 2017	May 2, 2017	May 12, 2017	$ 0.625	$ 9
December 31, 2016	February 10, 2017	February 15, 2017	$ 0.625	$ 9
September 30, 2016	November 1, 2016	November 14, 2016	$ 0.625	$ 9
June 30, 2016	August 2, 2016	August 12, 2016	$ 0.625	$ 9
March 31, 2016 (2)	May 6, 2016	May 13, 2016	$ 0.2917	$ 4

(1) The board of directors of Enable GP declared this $0.625 per Series A Preferred Unit cash distribution on February 9, 2018, which was paid on February 15, 2018 to Series A Preferred unitholders of record at the close of business on February 9, 2018.

(2) The prorated quarterly distribution for the Series A Preferred Units is for a partial period beginning on February 18, 2016, and ending on March 31, 2016, which equates to $0.625 per unit on a full-quarter basis or $2.50 per unit on an annualized basis.

General Partner Interest and Incentive Distribution Rights

Enable GP owns a non-economic general partner interest in the Partnership and, except as provided below with respect to incentive distribution rights, will not be entitled to distributions that the Partnership makes prior to the liquidation of the Partnership in respect of such general partner interest. Enable GP currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash the Partnership distributes from operating surplus (as defined in the Partnership Agreement) in excess of $0.330625 per unit per quarter. The maximum distribution of 50.0% does not include any distributions that Enable GP or its affiliates may receive on common units that they own.

Expiration of Subordination Period

Prior to the expiration of the subordination period, CenterPoint Energy and OGE Energy held 139,704,916 and 68,150,514 subordinated units, respectively. The financial tests required for conversion of all subordinated units were met and the 207,855,430 outstanding subordinated units converted into common units on a one-for-one basis on August 30, 2017. The conversion of the subordinated units did not change the aggregate amount of outstanding units, and the conversion of the subordinated units did not impact the amount of cash available for distribution by the Partnership.

Series A Preferred Units

On February 18, 2016, the Partnership completed the private placement of 14,520,000 Series A Preferred Units representing limited partner interests in the Partnership for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. The Partnership incurred approximately $1 million of expenses related to the offering, which is shown as an offset to the proceeds. In connection with the closing of the private placement, the Partnership redeemed approximately $363 million of notes scheduled to mature in 2017 payable to a wholly-owned subsidiary of CenterPoint Energy.

Pursuant to the Partnership Agreement, the Series A Preferred Units:

- rank senior to the Partnership's common units with respect to the payment of distributions and distribution of assets upon liquidation, dissolution and winding up;
- have no stated maturity;
- are not subject to any sinking fund; and
- will remain outstanding indefinitely unless repurchased or redeemed by the Partnership or converted into its common units in connection with a change of control.

Holders of the Series A Preferred Units receive a quarterly cash distribution on a non-cumulative basis if and when declared by the General Partner, and subject to certain adjustments, equal to an annual rate of: 10% on the stated liquidation preference of $25.00 from the date of original issue to, but not including, the five year anniversary of the original issue date; and thereafter a percentage of the stated liquidation preference equal to the sum of the three-month LIBOR plus 8.5%.

At any time on or after five years after the original issue date, the Partnership may redeem the Series A Preferred Units, in whole or in part, from any source of funds legally available for such purpose, by paying $25.50 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, the Partnership (or a third-party with its prior written consent) may redeem the Series A Preferred Units following certain changes in the methodology employed by ratings agencies, changes of control or fundamental transactions as set forth in the Partnership Agreement. If, upon a change of control or certain fundamental transactions, the Partnership (or a third-party with its prior written consent) does not exercise this option, then the holders of the Series A Preferred Units have the option to convert the Series A Preferred Units into a number of common units per Series A Preferred Unit as set forth in the Partnership Agreement. The Series A Preferred Units are also required to be redeemed in certain circumstances if they are not eligible for trading on the New York Stock Exchange.

Holders of Series A Preferred Units have no voting rights except for limited voting rights with respect to potential amendments to the Partnership Agreement that have a material adverse effect on the existing terms of the Series A Preferred Units, the issuance by the Partnership of certain securities, approval of certain fundamental transactions and as required by law.

Upon the transfer of any Series A Preferred Unit to a non-affiliate of CenterPoint Energy, the Series A Preferred Units will automatically convert into a new series of preferred units (the Series B Preferred Units) on the later of the date of transfer and the second anniversary of the date of issue. The Series B Preferred Units will have the same terms as the Series A Preferred Units except that unpaid distributions on the Series B Preferred Units will accrue on a cumulative basis until paid.

On February 18, 2016, the Partnership entered into a registration rights agreement with CenterPoint Energy, pursuant to which, among other things, the Partnership gave CenterPoint Energy certain rights to require the Partnership to file and maintain a registration statement with respect to the resale of the Series A Preferred Units and any other series of preferred units or common units representing limited partner interests in the Partnership that are issuable upon conversion of the Series A Preferred Units.

ATM Program

On May 12, 2017, the Partnership entered into an ATM Equity Offering Sales Agreement in connection with an at-the-market program (the "ATM Program"). Pursuant to the ATM Program, the Partnership may issue and sell common units having an aggregate offering price of up to $200 million, by sales methods and at prices determined by market conditions and other factors at the time of our offerings. The Partnership has no obligation to sell any common units under the ATM Program and the Partnership may suspend sales under the ATM Program at any time. For the year ended December 31, 2017, the Partnership sold an aggregate of 18,500 common units under the ATM Program, which generated proceeds of approximately $303,000 (net of approximately $3,000 of commissions). The Partnership incurred approximately $345,000 of expenses associated with the filing of the registration statements for the ATM Program. The proceeds were used for general partnership purposes.

2016 Equity Issuance

On November 29, 2016, the Partnership closed a public offering of 10,000,000 common units at a price to the public of $14.00 per common unit. In connection with the offering, the Partnership, the underwriters and an affiliate of ArcLight entered into an underwriting agreement that provided an option for the underwriters to purchase up to an additional 1,500,000 common units, with 75,719 common units to be sold by the Partnership and 1,424,281 to be sold by the affiliate of ArcLight. The underwriters exercised the option to purchase all of the additional common units, and the Partnership received proceeds (net of underwriting discounts, structuring fees and offering expenses) of $137 million from the offering.

(6) Property, Plant and Equipment

Property, plant and equipment includes the following:

	Weighted Average Useful Lives (Years)	December 31,	
		2017	2016
		(In millions)	
Property, plant and equipment, gross:			
Gathering and Processing	36	$ 7,322	$ 6,987
Transportation and Storage	34	4,538	4,498
Construction work-in-progress		219	82
Total		$ 12,079	$ 11,567
Accumulated depreciation:			
Gathering and Processing		865	681
Transportation and Storage		859	743
Total accumulated depreciation		1,724	1,424
Property, plant and equipment, net		$ 10,355	$ 10,143

The Partnership recorded depreciation expense of $335 million, $311 million and $291 million during the years ended December 31, 2017, 2016 and 2015, respectively.

(7) Intangible Assets, Net

The Partnership has intangible assets associated with customer relationships related to the acquisitions of Enogex, Monarch Natural Gas, LLC and Align Midstream, LLC as follows:

	December 31,	
	2017	2016
	(In millions)	
Customer relationships:		
Total intangible assets [1]	$ 581	$ 405
Accumulated amortization	130	99
Net intangible assets	$ 451	$ 306

(1) See Note 3 for discussion of the acquisition of Align Midstream, LLC during the year ended December 31, 2017.

Intangible assets related to customer relationships have a weighted average useful life of 13 years. Intangible assets do not have any significant residual value or renewal options of existing terms. There are no intangible assets with indefinite useful lives.

The Partnership recorded amortization expense of $31 million, $27 million and $27 million during the years ended December 31, 2017, 2016 and 2015, respectively. The following table summarizes the Partnership's expected amortization of intangible assets for each of the next five years:

	2018	2019	2020	2021	2022
	(In millions)				
Expected amortization of intangible assets	$ 45	$ 45	$ 45	$ 45	$ 45

(8) Goodwill

For the periods ended prior to September 30, 2015, the goodwill associated with the gathering and processing reportable segment is primarily related to the acquisitions of Enogex, Waskom and Monarch. The Partnership recognized $438 million of goodwill as a result of the acquisition of Enogex, which occurred at the time of the formation of the Partnership in 2013. The $579 million of goodwill associated with the transportation and storage reportable segment was related to the original acquisitions of EGT and MRT in 1997 by predecessors of the Partnership. Due to the continuing commodity price declines, the resulting decreases in forward commodity prices and forecasted producer activities, and an increase in the weighted average cost of capital, the Partnership determined that the impact on our forecasted discounted cash flows for our gathering and processing and transportation and storage reportable segments would be significantly reduced. As a result, when the Partnership performed our annual goodwill impairment analysis as of October 1, 2015, we determined that goodwill was completely impaired in the amount of $1,087 million, which is included in Impairments on the Consolidated Statements of Income for the year ended December 31, 2015. As a result, the Partnership did not have any goodwill recorded as of December 31, 2016. In the fourth quarter of 2017, as a result of the acquisition of Align Midstream, LLC, the Partnership recorded $12 million of goodwill, included in the gathering and processing reportable segment.

The change in carrying amount of goodwill in each of our reportable segments is as follows:

	Gathering and Processing	Transportation and Storage	Total
		(in millions)	
Balance as of December 31, 2014	$ 489	$ 579	$ 1,068
Monarch Acquisition [1]	19	—	19
Goodwill impairment	(508)	(579)	(1,087)
Balance as of December 31, 2015	$ —	$ —	$ —
Balance as of December 31, 2016	$ —	$ —	$ —
Align Acquisition [1]	12	—	12
Balance as of December 31, 2017	$ 12	$ —	$ 12

(1) See Note 3 for further discussion.

(9) Investment in Equity Method Affiliate

The Partnership uses the equity method of accounting for investments in entities in which it has an ownership interest between 20% and 50% and exercises significant influence.

For the period from December 31, 2014 through June 29, 2015, the Partnership held a 49.90% interest in SESH. On June 12, 2015, CenterPoint Energy exercised its put right with respect to its remaining 0.1% interest in SESH. Pursuant to the put right, on June 30, 2015, CenterPoint Energy contributed a 0.1% interest in SESH to the Partnership in exchange for 25,341 common units, which had a fair value of $1 million based upon the closing market price of the Partnership's common units. Spectra Energy Partners, LP owns the remaining 50% interest in SESH. Pursuant to the terms of the SESH LLC Agreement, if, at any time, CenterPoint Energy has a right to receive less than 50% of our distributions through its limited partner interest in the Partnership and its economic interest in Enable GP, or does not have the ability to exercise certain control rights, Spectra Energy Partners, LP may, under certain circumstances, have the right to purchase our interest in SESH at fair market value, subject to certain exceptions. For the years ended December 31, 2017 and 2016, the Partnership owned a 50% interest in SESH.

The Partnership shares operations of SESH with Spectra Energy Partners, LP under service agreements. The Partnership is responsible for the field operations of SESH. SESH reimburses each party for actual costs incurred, which are billed based upon a combination of direct charges and allocations. During the years ended December 31, 2017, 2016 and 2015, the Partnership billed SESH $17 million, $13 million and $12 million, respectively, associated with these service agreements.

The Partnership includes equity in earnings of equity method affiliate under the Other Income (Expense) caption in the Consolidated Statements of Income for the years ended December 31, 2017, 2016 and 2015.

Investment in Equity Method Affiliate:

	(In millions)
Balance as of December 31, 2014	**$ 348**
Interest acquisition of SESH	1
Equity in earnings of equity method affiliate	29
Contributions to equity method affiliate	8
Distributions from equity method affiliate (1)	(42)
Balance as of December 31, 2015	**344**
Equity in earnings of equity method affiliate	28
Distributions from equity method affiliate (1)	(43)
Balance as of December 31, 2016	**$ 329**
Equity in earnings of equity method affiliate	28
Distributions from equity method affiliate (1)	(33)
Balance as of December 31, 2017	**$ 324**

(1) Distributions from equity method affiliate includes a $28 million, $28 million and $34 million return on investment and a $5 million, $15 million and $8 million return of investment for the years ended December 31, 2017, 2016 and 2015, respectively.

Equity in Earnings of Equity Method Affiliate:

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
SESH	$ 28	$ 28	$ 29

Distributions from Equity Method Affiliate:

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
SESH	$ 33	$ 43	$ 42

Summarized financial information of SESH:

	December 31,	
	2017	2016
	(In millions)	
Balance Sheet Data:		
Current assets	$ 32	$ 31
Property, plant and equipment, net	1,093	1,110
Total assets	$ 1,125	$ 1,141
Current liabilities	$ 14	$ 18
Long-term debt	397	397
Members' equity	714	726
Total liabilities and members' equity	$ 1,125	$ 1,141
Reconciliation:		
Investment in SESH	$ 324	$ 329
Less: Capitalized interest on investment in SESH	(1)	(1)
Add: Basis differential, net of amortization	34	35
The Partnership's share of members' equity	$ 357	$ 363

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
Income Statement Data:			
Revenues	$ 113	$ 115	$ 115
Operating income	$ 72	$ 73	$ 71
Net income	$ 54	$ 55	$ 57

(10) Debt

The following table presents the Partnership's outstanding debt as of December 31, 2017 and 2016.

	December 31, 2017			December 31, 2016		
	Outstanding Principal	Premium (Discount)[1]	Total Debt	Outstanding Principal	Premium (Discount)[1]	Total Debt
			(In millions)			
Commercial Paper	405	—	405	—	—	—
Revolving Credit Facility	—	—	—	636	—	636
2015 Term Loan Agreement	450	—	450	450	—	450
2019 Notes	500	—	500	500	—	500
2024 Notes	600	—	600	600	(1)	599
2027 Notes	700	(3)	697	—	—	—
2044 Notes	550	—	550	550	—	550
EOIT Senior Notes	250	13	263	250	18	268
Total debt	3,455	10	3,465	2,986	17	3,003
Less: Short-term debt [2]			405			—
Less: Current portion of long-term debt			450			—
Less: Unamortized debt expense [3]			15			10
Total long-term debt			$ 2,595			$ 2,993

(1) Unamortized premium (discount) on long-term debt is amortized over the life of the respective debt.
(2) Short-term debt includes $405 million of commercial paper as of December 31, 2017. There was no commercial paper outstanding as of December 31, 2016.
(3) As of December 31, 2017 and 2016, there was an additional $3 million and $5 million, respectively, of unamortized debt expense related to the Revolving Credit Facility included in Other long-term assets, not included above. Unamortized debt expense is amortized over the life of the respective debt.

Maturities of outstanding debt, excluding unamortized premiums (discounts), are as follows (in millions):

2018	$ 855
2019	500
2020	250
2021	—
2022	—
Thereafter	1,850

Revolving Credit Facility

On June 18, 2015, the Partnership entered into the $1.75 billion Revolving Credit Facility, which matures on June 18, 2020, subject to an extension option, which may be exercised two times to extend the term of the Revolving Credit facility, in each case, for an additional one-year term. As of December 31, 2017, there were no principal advances and $3 million in letters of credit outstanding under the Revolving Credit Facility.

The Revolving Credit Facility provides that outstanding borrowings bear interest at LIBOR and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on the Partnership's applicable credit ratings. As of December 31, 2017, the applicable margin for LIBOR-based borrowings under the Revolving Credit Facility was 1.50% based on the Partnership's credit ratings. In addition, the Revolving Credit Facility requires the Partnership to pay a fee on unused commitments. The commitment fee is based on the Partnership's applicable credit rating from the rating agencies. As of December 31, 2017, the commitment fee under the Revolving Credit Facility was 0.20% per annum based on the Partnership's credit ratings. The commitment fee is recorded as interest expense in the Partnership's Consolidated Statements of Income.

The Revolving Credit Facility contains a financial covenant requiring us to maintain a ratio of consolidated funded debt to consolidated EBITDA as defined under the Revolving Credit Facility as of the last day of each fiscal quarter of less than or equal to 5.00 to 1.00; provided that, for any three fiscal quarters including and following any fiscal quarter in which the aggregate value of one or more acquisitions by us or certain of our subsidiaries with a purchase price of at least $25 million in the aggregate, the consolidated funded debt to consolidated EBITDA ratio as of the last day of each such fiscal quarter during such period would be permitted to be up to 5.50 to 1.00.

The Revolving Credit Facility also contains covenants that restrict us and certain subsidiaries in respect of, among other things, mergers and consolidations, sales of all or substantially all assets, incurrence of subsidiary indebtedness, incurrence of liens, transactions with affiliates, designation of subsidiaries as Excluded Subsidiaries (as defined in the Revolving Credit Facility), restricted payments, changes in the nature of their respective businesses and entering into certain restrictive agreements. Borrowings under the Revolving Credit Facility are subject to acceleration upon the occurrence of certain defaults, including, among others, payment defaults on such facility, breach of representations, warranties and covenants, acceleration of indebtedness (other than intercompany and non-recourse indebtedness) of $100 million or more in the aggregate, change of control, nonpayment of uninsured money judgments in excess of $100 million and the occurrence of certain ERISA and bankruptcy events, subject where applicable to specified cure periods.

Commercial Paper

The Partnership has a commercial paper program pursuant to which the Partnership is authorized to issue up to $1.4 billion of commercial paper. The commercial paper program is supported by our Revolving Credit Facility, and outstanding commercial paper effectively reduces our borrowing capacity thereunder. There was $405 million and zero outstanding under our commercial paper program as of December 31, 2017 and 2016, respectively. The weighted average interest rate for the outstanding commercial paper was 2.42% as of December 31, 2017.

Term Loan Agreement

On July 31, 2015, the Partnership entered into a Term Loan Agreement, providing for an unsecured three-year $450 million term loan agreement (2015 Term Loan Agreement). The entire $450 million principal amount of the 2015 Term Loan Agreement was borrowed by the Partnership on July 31, 2015. The 2015 Term Loan Agreement contains an option, which may be exercised up to two times, to extend the term of the 2015 Term Loan Agreement, in each case, for an additional one-year term. The 2015 Term Loan Agreement provides an option to prepay, without penalty or premium, the amount outstanding, or any portion thereof, in a minimum amount of $1 million, or any multiple of $0.5 million in excess thereof. As of December 31, 2017, there was $450 million outstanding under the 2015 Term Loan Agreement, which is included as Short-term debt in the Partnership's Consolidated Balance Sheets.

The 2015 Term Loan Agreement provides that outstanding borrowings bear interest at LIBOR and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on our applicable credit ratings. As of December 31, 2017, the applicable margin for LIBOR-based borrowings under the 2015 Term Loan Agreement was 1.375% based on our credit ratings. For the year ended December 31, 2017, the weighted average interest rate of the 2015 Term Loan Agreement was 2.45%.

The 2015 Term Loan Agreement contains substantially the same covenants as the Revolving Credit Facility.

Senior Notes

On March 9, 2017, the Partnership completed the public offering of $700 million 4.400% Senior Notes due 2027 (2027 Notes). The Partnership received net proceeds of approximately $691 million. The proceeds were used for general partnership purposes, including to repay amounts outstanding under the Revolving Credit Facility. The 2027 Notes had an unamortized discount

of $3 million and unamortized debt expense of $6 million at December 31, 2017, resulting in an effective interest rate of 4.56% during the year ended December 31, 2017.

In addition to the 2027 Notes, as of December 31, 2017, the Partnership's debt included the $500 million 2.400% senior notes due 2019 (2019 Notes), $600 million 3.900% senior notes due 2024 (2024 Notes) and $550 million 5.000% senior notes due 2044 (2044 Notes). The 2019 Notes, 2024 Notes and 2044 Notes had $9 million of unamortized debt expense at December 31, 2017, resulting in effective interest rates of 2.58%, 4.02% and 5.08%, respectively, during the year ended December 31, 2017.

The indenture governing the 2019 Notes, 2024 Notes, 2027 Notes and 2044 Notes contains certain restrictions, including, among others, limitations on our ability and the ability of our principal subsidiaries to: (i) consolidate or merge and sell all or substantially all of our and our subsidiaries' assets and properties; (ii) create, or permit to be created or to exist, any lien upon any of our or our principal subsidiaries' principal property, or upon any shares of stock of any principal subsidiary, to secure any debt; and (iii) enter into certain sale-leaseback transactions. These covenants are subject to certain exceptions and qualifications.

As of December 31, 2017, the Partnership's debt included EOIT's $250 million 6.25% senior notes due March 2020 (the EOIT Senior Notes). The EOIT Senior Notes had $13 million of unamortized premium at December 31, 2017, resulting in an effective interest rate of 3.83% during the year ended December 31, 2017. These senior notes do not contain any financial covenants other than a limitation on liens. This limitation on liens is subject to certain exceptions and qualifications.

As of December 31, 2017, the Partnership and EOIT were in compliance with all of their debt agreements, including financial covenants.

(11) Derivative Instruments and Hedging Activities

The Partnership is exposed to certain risks relating to its ongoing business operations. The primary risk managed using derivative instruments is commodity price risk. The Partnership is also exposed to credit risk in its business operations.

Commodity Price Risk

The Partnership has used forward physical contracts, commodity price swap contracts and commodity price option features to manage the Partnership's commodity price risk exposures in the past. Commodity derivative instruments used by the Partnership are as follows:

- NGL put options, NGL futures and swaps, and WTI crude oil futures and swaps for condensate sales are used to manage the Partnership's NGL and condensate exposure associated with its processing agreements;
- natural gas futures and swaps are used to manage the Partnership's natural gas exposure associated with its gathering, processing and transportation and storage assets; and
- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage the Partnership's natural gas exposure associated with its storage and transportation contracts and asset management activities.

Normal purchases and normal sales contracts are not recorded in Other Assets or Liabilities in the Consolidated Balance Sheets and earnings are recognized and recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by the Partnership's operations and (ii) commodity contracts for the purchase and sale of NGLs produced by the Partnership's gathering and processing business.

The Partnership recognizes its non-exchange traded derivative instruments as Other Assets or Liabilities in the Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Consolidated Balance Sheets.

As of December 31, 2017 and 2016, the Partnership had no derivative instruments that were designated as cash flow or fair value hedges for accounting purposes.

Credit Risk

The Partnership is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe the Partnership money or energy will breach their obligations. If the counterparties to these arrangements

fail to perform, the Partnership may seek or be forced to enter into alternative arrangements. In that event, the Partnership's financial results could be adversely affected, and the Partnership could incur losses.

Derivatives Not Designated as Hedging Instruments

Derivative instruments not designated as hedging instruments for accounting purposes are utilized in the Partnership's asset management activities. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings.

Quantitative Disclosures Related to Derivative Instruments

The majority of natural gas physical purchases and sales not designated as hedges for accounting purposes are priced based on a monthly or daily index, and the fair value is subject to little or no market price risk. Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via the Partnership's processing contracts, which are not derivative instruments.

As of December 31, 2017 and 2016, the Partnership had the following derivative instruments that were not designated as hedging instruments for accounting purposes:

	December 31, 2017		December 31, 2016	
	Gross Notional Volume			
	Purchases	Sales	Purchases	Sales
Natural gas— TBtu [1]				
Financial fixed futures/swaps	17	13	2	29
Financial basis futures/swaps	17	17	2	30
Physical purchases/sales	1	37	1	25
Crude oil (for condensate)— MBbl [2]				
Financial futures/swaps	—	564	—	540
Natural gas liquids— MBbl [3]				
Financial futures/swaps	—	1,615	60	1,133

(1) As of December 31, 2017, 67.7% of the natural gas contracts have durations of one year or less, 16.1% have durations of more than one year and less than two years and 16.2% have durations of more than two years. As of December 31, 2016, 100.0% of the natural gas contracts had durations of one year or less.
(2) As of December 31, 2017 and 2016, 100% of the crude oil (for condensate) contracts have durations of one year or less.
(3) As of December 31, 2017 and 2016, 100.0% of the natural gas liquid contracts have durations of one year or less.

Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in the Partnership's Consolidated Balance Sheet at December 31, 2017 and 2016 that were not designated as hedging instruments for accounting purposes are as follows:

		December 31, 2017		December 31, 2016	
		Fair Value			
Instrument	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
		(In millions)			
Natural gas					
Financial futures/swaps	Other Current	$ 5	$ 4	$ 2	$ 22
Physical purchases/sales	Other Current	3	—	—	1
Crude oil (for condensate)					
Financial futures/swaps	Other Current	—	4	—	3
Natural gas liquids					
Financial futures/swaps	Other Current	1	5	—	8
Total gross derivatives [1]		$ 9	$ 13	$ 2	$ 34

(1) See Note 12 for a reconciliation of the Partnership's total derivatives fair value to the Partnership's Consolidated Balance Sheets as of December 31, 2017 and 2016.

Income Statement Presentation Related to Derivative Instruments

The following table presents the effect of derivative instruments on the Partnership's Consolidated Statements of Income for the years ended December 31, 2017, 2016 and 2015:

	Amounts Recognized in Income		
	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
Natural gas financial futures/swaps gains (losses)	$ 20	$ (19)	$ 26
Natural gas physical purchases/sales gains (losses)	9	(7)	(9)
Crude oil (for condensate) financial futures/swaps gains (losses)	(1)	(4)	12
Natural gas liquids financial futures/swaps gains (losses)	(9)	(13)	10
Total	$ 19	$ (43)	$ 39

For derivatives not designated as hedges in the tables above, amounts recognized in income for the years ended December 31, 2017, 2016 and 2015, if any, are reported in Product sales.

The following table presents the components of gain (loss) on derivative activity in the Partnership's Consolidated Statements of Income for the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
Change in fair value of derivatives	$ 28	$ (60)	$ (8)
Realized gain (loss) on derivatives	(9)	17	47
Gain (loss) on derivative activity	$ 19	$ (43)	$ 39

Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Partnership's senior unsecured debt rating to a below investment grade rating, at December 31, 2017, the Partnership would have been required to

post $7 million cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at December 31, 2017. In addition, the Partnership could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

(12) Fair Value Measurements

Certain assets and liabilities are recorded at fair value in the Consolidated Balance Sheets and are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined below and directly related to the amount of subjectivity associated with the inputs to fair valuations of these assets and liabilities are as follows:

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and options transactions for contracts traded on the NYMEX and settled through a NYMEX clearing broker.

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing, and over-the-counter WTI crude oil swaps for condensate sales.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. Unobservable inputs reflect the Partnership's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Partnership develops these inputs based on the best information available, including the Partnership's own data.

The Partnership utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX or WTI published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX or WTI based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management's best estimate of fair value. These contracts are classified as Level 3.

The Partnership determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes transfers between levels at the end of the reporting period. For the period ended December 31, 2017, there were no transfers between Level 2 and Level 3 instruments.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor's Ratings Services and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

Estimated Fair Value of Financial Instruments

The fair values of all accounts receivable, notes receivable, accounts payable, commercial paper and other such financial instruments on the Consolidated Balance Sheets are estimated to be approximately equivalent to their carrying amounts and have been excluded from the table below. The following table summarizes the fair value and carrying amount of the Partnership's financial instruments at December 31, 2017 and 2016:

	December 31, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Debt				
Revolving Credit Facility (Level 2) [1]	$ —	$ —	$ 636	$ 636
2015 Term Loan Agreement (Level 2)	450	450	450	450
2019 Notes (Level 2)	500	497	500	490
2024 Notes (Level 2)	600	602	599	564
2027 Notes (Level 2)	697	712	—	—
2044 Notes (Level 2)	550	550	550	467
EOIT Senior Notes (Level 2)	263	265	268	260

(1) Borrowing capacity is effectively reduced by our borrowings outstanding under the commercial paper program. $405 million and zero of commercial paper was outstanding as of December 31, 2017 and 2016, respectively.

The fair value of the Partnership's Revolving Credit Facility, 2015 Term Loan Agreement, 2019 Notes, 2024 Notes, 2027 Notes, 2044 Notes, and EOIT Senior Notes, is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

Non-Financial Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis; that is, the assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment).

During the years ended December 31, 2016 and 2015, the Partnership remeasured the Service Star assets at fair value and reassessed the carrying value of the Service Star business line, a component of the gathering and processing segment that provides measurement and communication services to third parties. The 2016 impairment, which impaired substantially all of the remaining net book value of the Service Star business line, was primarily driven by the impact of planned technology changes affecting Service Star. The 2015 impairment was based upon higher than expected losses of customers. Based on forecasted future undiscounted cash flows management determined that the carrying value of the Service Star assets were not fully recoverable. The Partnership utilized the income approach (generally accepted valuation approach) to estimate the fair value of these assets. The primary inputs are forecasted cash flows and the discount rate. The fair value measurement is based on inputs that are not observable in the market and thus represent level 3 inputs. Applying a discounted cash flow model to the property, plant and equipment and reviewing the associated materials and supplies inventory, during the years ended December 31, 2016 and 2015, the Partnership recognized a $9 million and $10 million impairment, respectively. The 2016 impairment consisted of an $8 million write-down of property, plant and equipment and a $1 million write-down of materials and supplies inventory considered either excess or obsolete. The 2015 impairment consisted of a $9 million write-down of property, plant and equipment and a $1 million write-down of materials and supplies inventory considered either excess or obsolete.

At December 31, 2015, due to decreases of crude oil and natural gas prices during 2015, management reassessed the carrying value of the Partnership's investment in the Atoka assets, a component of the gathering and processing segment. Based on forecasted future undiscounted cash flows, management determined that the carrying value of the Atoka assets were not fully recoverable. The Partnership utilized the income approach (generally accepted valuation approach) to estimate the fair value of these assets. The primary inputs are forecast cash flows and the discount rate. The fair value measurement is based on inputs that are not observable in the market and thus represent level 3 inputs. Applying a discounted cash flow model to the property, plant and equipment and intangible assets, the Partnership recognized a $25 million impairment during the year ended December 31, 2015. The $25 million impairment consisted of a $19 million write-down of property, plant and equipment and a $6 million write-down of intangible assets.

Additionally, during the year ended December 31, 2015, the Partnership recorded a $12 million impairment on jurisdictional pipelines in our transportation and storage segment.

Based upon review of forecasted undiscounted cash flows as of December 31, 2017, all of the asset groups were considered recoverable. Future price declines, throughput declines, contracted capacity declines, cost increases, regulatory or political

environment changes and other changes in market conditions could reduce forecasted undiscounted cash flows.

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Consolidated Balance Sheets. The Partnership has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation.

The following tables summarize the Partnership's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2017 and 2016:

December 31, 2017	Commodity Contracts		Gas Imbalances [1]	
	Assets	Liabilities	Assets [2]	Liabilities [3]
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$ 5	$ 3	$ —	$ —
Significant other observable inputs (Level 2)	4	5	27	12
Unobservable inputs (Level 3)	—	5	—	—
Total fair value	9	13	27	12
Netting adjustments	(5)	(5)	—	—
Total	$ 4	$ 8	$ 27	$ 12

December 31, 2016	Commodity Contracts		Gas Imbalances [1]	
	Assets	Liabilities	Assets [2]	Liabilities [3]
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$ 2	$ 22	$ —	$ —
Significant other observable inputs (Level 2)	—	4	41	30
Unobservable inputs (Level 3)	—	8	—	—
Total fair value	2	34	41	30
Netting adjustments	—	—	—	—
Total	$ 2	$ 34	$ 41	$ 30

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(1) The Partnership uses the market approach to fair value its gas imbalance assets and liabilities at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value. Gas imbalances held by EOIT are valued using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices. There were no netting adjustments as of December 31, 2017 and 2016.

(2) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $10 million and zero at December 31, 2017 and 2016, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

(3) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of zero and $5 million at December 31, 2017 and 2016, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

Changes in Level 3 Fair Value Measurements

The following tables provides a reconciliation of changes in the fair value of our Level 3 financial assets between the periods presented.

	Commodity Contracts
	Natural gas liquids financial futures/swaps
	(In millions)
Balance as of December 31, 2015	$ 4
Losses included in earnings	(13)
Settlements	1
Transfers out of Level 3	—
Balance as of December 31, 2016	(8)
Losses included in earnings	(9)
Settlements	12
Transfers out of Level 3	—
Balance as of December 31, 2017	$ (5)

Quantitative Information on Level 3 Fair Value Measurements

The Partnership utilizes the market approach to measure the fair value of our commodity contracts. The significant unobservable inputs used in this approach to fair value are longer dated price quotes. Our sensitivity to these longer dated forward curve prices are presented in the table below. Significant changes in any of those inputs in isolation would result in significantly different fair value measurements, depending on our short or long position in contracts.

	December 31, 2017	
Product Group	Fair Value	Forward Curve Range
	(In millions)	(Per gallon)
Natural gas liquids	$ (5)	$0.267 - $1.090

(13) Supplemental Disclosure of Cash Flow Information

The following table provides information regarding supplemental cash flow information:

	Year Ended December 31,		
	2017	2016	2015
		(In millions)	
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 114	$ 105	$ 85
Income taxes, net of refunds	—	—	1
Non-cash transactions:			
Accounts payable related to capital expenditures	39	18	52
Issuance of common units upon interest acquisition of SESH (Note 9)	—	—	1

The following table reconciles cash and cash equivalents and restricted cash on the Consolidated Balance Sheets to cash, cash equivalents and restricted cash on the Consolidated Statement of Cash Flows:

	Year Ended December 31,	
	2017	2016
	(In millions)	
Cash and cash equivalents	$ 5	$ 6
Restricted cash	14	17
Cash, cash equivalents and restricted cash shown in the Consolidated Statement of Cash Flows	$ 19	$ 23

(14) Related Party Transactions

The material related party transactions with CenterPoint Energy, OGE Energy and their respective subsidiaries are summarized below. There were no material related party transactions with other affiliates.

Transportation and Storage Agreements

Transportation and Storage Agreements with CenterPoint Energy

EGT provides the following services to CenterPoint Energy's LDCs in Arkansas, Louisiana, Oklahoma and Northeast Texas: (1) firm transportation with seasonal contract demand, (2) firm storage, (3) no notice transportation with associated storage and (4) maximum rate firm transportation. The first three services are in effect through March 31, 2021, and will remain in effect from year to year thereafter unless either party provides 180 days' written notice prior to the contract termination date. The fourth service is in effect through March 31, 2018 unless extended by the parties. MRT provides firm transportation and firm storage services to CenterPoint Energy's LDCs under agreements that are in effect through May 15, 2023, but will continue year to year thereafter unless either party provides twelve months' written notice prior to the contract termination date.

The Partnership may agree to reimburse the costs that its customers incur to make required modifications for the repair and maintenance of pipelines that impact customer delivery points. For the years ended December 31, 2017 and 2016, we reimbursed CenterPoint Energy's LDCs $1 million and $2 million, respectively, in connection with receipt facility modifications that were necessitated by the repair and maintenance of our pipelines.

In 2015, EGT relocated a portion of its pipeline in Arkansas to improve reliability and increase capacity by constructing an approximately 28.5 mile new pipeline segment and abandoning approximately 34.2 miles of existing pipelines segments. In connection with the project, EGT sold an approximately 12.4 mile pipeline segment to CenterPoint Energy's Arkansas LDC for its remaining book value of $1 million, and EGT reimbursed CenterPoint Energy's Arkansas LDC approximately $7 million dollars for cost incurred in connecting the LDC to EGT's new pipeline segment.

Transportation and Storage Agreement with OGE Energy

EOIT provides no-notice load-following transportation and storage services to OGE Energy under two contracts. The first contract with OGE Energy is in effect through April 30, 2019 and will remain in effect from year to year thereafter unless either party provides notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period. The second contract with OGE Energy was entered into on December 6, 2016 and has a primary term of 20 years that is expected to begin in late 2018. In connection with this agreement, we are currently building an approximately 80-mile pipeline to expand the EOIT system.

Gas Sales and Purchases Transactions

The Partnership sells natural gas volumes to affiliates of CenterPoint Energy and OGE Energy or purchases natural gas volumes from affiliates of CenterPoint Energy through a combination of forward, monthly and daily transactions. The Partnership enters into these physical natural gas transactions in the normal course of business based upon relevant market prices.

The Partnership's revenues from affiliated companies accounted for 5%, 7% and 7% of revenues during the years ended December 31, 2017, 2016 and 2015, respectively. Amounts of revenues from affiliated companies included in the Partnership's Consolidated Statements of Income are summarized as follows:

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
Gas transportation and storage service revenue — CenterPoint Energy	$ 110	$ 110	$ 110
Natural gas product sales — CenterPoint Energy	6	1	7
Gas transportation and storage service revenue — OGE Energy	35	36	37
Natural gas product sales — OGE Energy	2	12	8
Total revenues — affiliated companies	$ 153	$ 159	$ 162

Amounts of natural gas purchased from affiliated companies included in the Partnership's Consolidated Statements of Income are summarized as follows:

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
Cost of natural gas purchases — CenterPoint Energy	$ 1	$ —	$ 2
Cost of natural gas purchases — OGE Energy	19	14	15
Total cost of natural gas purchases — affiliated companies	$ 20	$ 14	$ 17

Seconded employee, corporate services and operating lease expense

During the years ended December 31, 2017, 2016 and 2015, the Partnership had certain employees who are participants under OGE Energy's defined benefit and retiree medical plans, who will remain seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy. The Partnership's reimbursement of OGE Energy for seconded employee costs arising out of OGE Energy's defined benefit and retiree medical plans is fixed at $5 million in 2017 and at actual cost subject to a cap of $5 million in 2018 and thereafter, unless and until secondment is terminated.

The Partnership receives services and support functions from each of CenterPoint Energy and OGE Energy under service agreements for an initial term that ended on April 30, 2016. The service agreements automatically extend year-to-year at the end of the initial term, unless terminated by the Partnership with at least 90 days' notice prior to the end of any extension. Additionally, the Partnership may terminate these service agreements at any time with 180 days' notice, if approved by the Board of Enable GP. The Partnership reimburses CenterPoint Energy and OGE Energy for these services up to annual caps, which for 2017 are $3 million and $4 million, respectively.

The Partnership leases office and data center space from an affiliate of CenterPoint Energy in Shreveport, Louisiana. The term of the lease was effective on October 1, 2016 and extends through December 31, 2019. The Partnership incurred approximately $1 million in rent and maintenance expenses under the lease during the year ended December 31, 2017 and the Partnership expects to incur approximately $1 million in total in rent and maintenance expenses during the remaining term of the lease.

Amounts charged to the Partnership by affiliates for seconded employees, corporate services and operating lease expense, included primarily in Operation and maintenance expenses and General and administrative expenses in the Partnership's Consolidated Statements of Income are as follows:

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
Corporate Services — CenterPoint Energy	$ 3	$ 6	$ 15
Operating Lease — CenterPoint Energy	1	—	—
Seconded Employee Costs — OGE Energy	31	29	35
Corporate Services — OGE Energy	3	5	11
Total seconded employee, corporate services and operating lease expense	$ 38	$ 40	$ 61

Series A Preferred Units

On February 18, 2016, the Partnership completed the private placement, with CenterPoint Energy, of 14,520,000 Series A Preferred Units representing limited partner interests in the Partnership for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. See Note 5 for further discussion of the Series A Preferred Units.

Notes payable

The Partnership had outstanding long-term notes payable—affiliated companies to CenterPoint Energy at December 31, 2015 of $363 million, which were scheduled to mature in 2017. On February 18, 2016, in connection with the private placement of the Series A Preferred Units, the Partnership redeemed the $363 million of notes payable—affiliated companies payable to a subsidiary of CenterPoint Energy.

The Partnership recorded affiliated interest expense to CenterPoint Energy on note payable—affiliated companies of zero, $1 million and $8 million during the years ended December 31, 2017, 2016 and 2015, respectively.

(15) Commitments and Contingencies

Operating Lease Obligations. The Partnership has operating lease obligations expiring at various dates. Future minimum payments for noncancellable operating leases are as follows:

	Year Ended December 31,						
	2018	2019	2020	2021	2022	After 2022	Total
	(In millions)						
Noncancellable operating leases	$ 10	$ 3	$ 1	$ 1	$ 1	$ 1	$ 17

Total rental expense for all operating leases was $27 million, $27 million and $32 million during the years ended December 31, 2017, 2016 and 2015, respectively.

The Partnership currently occupies 162,053 square feet of office space at its principle executive offices under a lease that expires June 30, 2019. The lease payments are $19 million over the lease term, which began April 1, 2012. These lease expenses are included in General and administrative expense in the Consolidated Statements of Income.

During 2017, the Partnership entered into a lease to occupy 48,642 square feet of office space in Houston, Texas, which ends December 31, 2025. The lease payments are $4 million over the lease term, as well as a proportionate percentage of facility expenses.

The Partnership currently has 104 compression service agreements, of which 62 agreements are on a month-to-month basis, 34 agreements will expire in 2018 and 8 agreements will expire in 2019. The Partnership also has 6 gas treating lease agreements, all of which are on a month-to-month basis. These lease expenses are reflected in Operation and maintenance expense in the Consolidated Statements of Income.

Legal, Regulatory and Other Matters

The Partnership is involved in legal, environmental, tax and regulatory proceedings before various courts, regulatory

commissions and governmental agencies regarding matters arising in the ordinary course of business. Some of these proceedings involve substantial amounts. The Partnership regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. The Partnership does not expect the disposition of these matters to have a material adverse effect on its financial condition, results of operations or cash flows.

(16) Income Taxes

The Partnership's earnings are generally not subject to income tax (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiaries, Enable Midstream Services and Enable Muskogee Intrastate Transmission) and are taxable at the individual partner level. The Partnership and its non-corporate subsidiaries are pass-through entities for federal income tax purposes. For these entities, all income, expenses, gains, losses and tax credits generated flow through to their owners and, accordingly, do not result in a provision for income taxes in the consolidated financial statements. Consequently, the Consolidated Statements of Income do not include an income tax provision (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiaries). On December 22, 2017, the act known as the "Tax Cuts and Jobs Act," was signed into law which lowered the corporate tax rate from 35% to 21% for tax years beginning after December 31, 2017. As a result of this new law, the Partnership's corporate subsidiaries re-valued their deferred income tax assets and liabilities as of December 31, 2017, which resulted in recording a Federal deferred income tax benefit of $1 million.

The items comprising income tax expense are as follows:

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
Provision (benefit) for current income taxes			
Federal	$ 1	$ (1)	$ —
State	1	—	1
Total provision (benefit) for current income taxes	2	(1)	1
Provision (benefit) for deferred income taxes, net			
Federal	$ (2)	3	$ —
State	(1)	(1)	(1)
Total provision (benefit) for deferred income taxes, net	(3)	2	(1)
Total income tax expense (benefit)	$ (1)	$ 1	$ —

The following schedule reconciles the statutory Federal income tax rate to the effective income tax rate:

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
Income (loss) before income taxes	$ 436	$ 314	$ (771)
Federal statutory rate	— %	—%	—%
Expected federal income tax expense	—	—	—
Increase in tax expense (benefit) resulting from:			
State income taxes, net of federal income tax	(1)	1	—
Total	(1)	1	—
Total income tax expense (benefit)	$ (1)	$ 1	$ —
Effective tax rate	(0.2)%	0.3%	—%

The components of Deferred Income Taxes as of December 31, 2017 and 2016 were as follows:

	December 31,	
	2017	2016
	(In millions)	
Deferred tax assets:		
Non-current:		
Accrued bonuses	$ 17	$ —
Total non-current deferred tax assets	17	—
Total deferred tax assets	17	—
Deferred tax liabilities:		
Non-current:		
Depreciation	5	7
Intercompany management fee	18	3
Total non-current deferred tax liabilities	23	10
Accumulated deferred income taxes, net	$ 6	$ 10

Uncertain Income Tax Positions

There were no unrecognized tax benefits as of December 31, 2017, 2016 and 2015.

Tax Audits and Settlements

The federal income tax return of the Partnership has been audited through the 2013 tax year.

(17) Equity-Based Compensation

Enable GP has adopted the Enable Midstream Partners, LP Long Term Incentive Plan (LTIP) for officers, directors and employees of the Partnership and its affiliates, including any individual who provides services to the Partnership as a seconded employee. The long-term incentive plan provides for the following types of awards: restricted units, phantom units, appreciations rights, option rights, cash incentive awards, performance units, distribution equivalent rights, and other awards denominated in, payable in, valued in or otherwise based on or related to common units.

The long-term incentive plan is administered by the Compensation Committee of the Board of Directors. With respect to any grant of equity as long-term incentive awards to our independent directors and our officers subject to reporting under Section 16 of the Exchange Act, the Compensation Committee makes recommendations to the Board of Directors and any such awards will only be effective upon the approval of the Board of Directors. The long-term incentive plan limits the number of units that may be delivered pursuant to vested awards to 13,100,000 common units, subject to proportionate adjustment in the event of unit splits and similar events. Common units cancelled, forfeited, expired or cash settled are available for delivery pursuant to other awards.

The Board of Directors may terminate or amend the long-term incentive plan at any time with respect to any units for which a grant has not yet been made, including amending the long-term incentive plan to increase the number of units that may be granted subject to the requirements of the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would be adverse to the participant without the consent of the participant.

Performance unit, restricted unit and phantom unit awards are classified as equity on the Partnership's Consolidated Balance Sheet. The following table summarizes the Partnership's equity-based compensation expense for the years ended December 31, 2017, 2016 and 2015 related to performance units, restricted units and phantom units for the Partnership's employees and independent directors:

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
Performance units	$ 10	$ 9	$ 3
Restricted units	2	3	7
Phantom units	3	1	1
Total equity-based compensation expense	$ 15	$ 13	$ 11

Performance Units

Awards of performance based phantom units (performance units) have been made under the LTIP in 2017, 2016 and 2015 to certain officers and employees providing services to the Partnership. Subject to the achievement of performance goals, the performance unit awards cliff vest three years from the grant date, with distribution equivalent rights paid at vesting. The performance goals for 2017, 2016 and 2015 awards are based on total unitholder return over a three-calendar year performance cycle. Total unitholder return is based on the relative performance of the Partnership's common units against a peer group. The performance unit awards have a payout from zero to 200% of the target based on the level of achievement of the performance goal. Performance unit awards are paid out in common units, with distribution equivalent rights paid in cash at vesting. Any unearned performance units are cancelled. Pay out requires the confirmation of the achievement of the performance level by the Compensation Committee. Prior to vesting, performance units are subject to forfeiture if the recipient's employment with the Partnership is terminated for any reason other than death, disability, retirement or termination other than for cause within two years of a change in control. In the event of retirement, a participant will receive a prorated payment based on the target performance, rather than actual performance, of the performance goals during the award cycle.

The fair value of each performance unit award was estimated on the grant date using a lattice-based valuation model. The valuation information factored into the model includes the expected distribution yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition over the expected life of the performance units. Equity-based compensation expense for each performance unit award is a fixed amount determined at the grant date fair value and is recognized over the three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Distributions are accumulated and paid at vesting and, therefore, are included in the fair value calculation of the performance unit award. The expected price volatility for the awards granted in 2017 is based on three years of daily stock price observations, to determine the total unitholder return ranking. The expected price volatility for the awards granted in 2016 is based on two years of daily stock price observations, combined with the average of the one-year volatility of the applicable peer group companies used to determine the total unitholder return ranking. The expected price volatility for the awards granted in 2015 is based on one year of daily stock price observations, combined with the average of the two-year volatility of the applicable peer group companies used to determine the total unitholder return ranking. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. There are no post-vesting restrictions related to the Partnership's performance units. The number of performance units granted based on total unitholder return and the assumptions used to calculate the grant date fair value of the performance units based on total unitholder return are shown in the following table.

	2017	2016	2015
Number of units granted	468,626	1,235,429	501,474
Fair value of units granted	$ 19.27	$10.42 - $27.77	$ 16.59
Expected price volatility	47.3%	43.2% - 46.0%	27.6%
Risk-free interest rate	1.57%	0.86% - 0.90%	0.99%
Expected life of units (in years)	3	3	3

Phantom Units

Awards of phantom units have been made under the LTIP in 2017, 2016 and 2015 to certain officers and employees providing services to the Partnership and certain directors of Enable GP. Phantom units vest on the first, second or third anniversary of the

grant date with distribution equivalent rights paid during the vesting period. Phantom unit awards are paid out in common units, with distributions equivalent rights paid in cash. Phantom units cliff-vest at the end of the vesting period. Any unearned phantom units are cancelled. Prior to vesting, phantom units are subject to forfeiture if the recipient's employment with the Partnership is terminated for any reason other than death, disability, retirement or termination other than for cause within two years of a change in control.

The fair value of the phantom units was based on the closing market price of the Partnership's common unit on the grant date. Equity-based compensation expense for the phantom unit is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over the vesting period. Distributions on phantom units are paid during the vesting period and, therefore, are included in the fair value calculation. The expected life of the phantom unit is based on the applicable vesting period. The number of phantom units granted and the grant date fair value are shown in the following table.

	2017	2016	2015
Phantom units granted	392,338	653,286	9,817
Fair value of phantom units granted	$15.44 - $16.93	$8.12 - $15.30	$ 12.70

Restricted Units

Awards of restricted units were made under the LTIP in 2015 to certain officers and employees providing services to the Partnership and certain directors of Enable GP. These restricted unit awards cliff vest on the first, second, third or fourth anniversary of grant date, with distribution equivalent rights paid during the vesting period. Restricted units are outstanding and issued common units that cannot be sold, assigned, transferred or pledged by the recipient prior to vesting. Any unearned restricted units are cancelled. Prior to vesting, restricted units are subject to forfeiture if the recipient ceases to render substantial services to the Partnership for any reason other than death, disability, retirement or termination other than for cause within two years of a change in control.

In 2015, restricted units were granted to officers and employees providing services to the Partnership which vest on the first, second, or third anniversary of grant date. Prior to vesting, each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to the Partnership for any reason other than death, disability or retirement. During the restriction period these units may not be sold, assigned, transferred or pledged and are subject to a risk of forfeiture.

The fair value of the restricted units was based on the closing market price of the Partnership's common unit on the grant date. Equity-based compensation expense for the restricted units is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a vesting period, as defined in the agreements. Distributions are paid as declared prior to vesting and, therefore, are included in the fair value calculation. After payment, distributions are not subject to forfeiture. The expected life of the restricted units is based on the non-vested period since inception of the award cycle.

The number of restricted units granted related to the Partnership's employees and the grant date fair value are shown in the following table.

	2015
Restricted units granted to the Partnership's employees	279,677
Fair value of restricted units granted	$16.75 - $19.18

Other Awards

In 2017, 2016 and 2015, the Board of Directors granted common units to the independent directors of Enable GP, for their service as directors, which vested immediately. The fair value of the common units was based on the closing market price of the Partnership's common unit on the grant date.

	2017	2016	2015
Common units granted	16,653	14,914	17,384
Fair value of common units granted	$ 15.03	$ 15.35	$ 11.12

Units Outstanding

A summary of the activity for the Partnership's performance units, restricted units and phantom units as of December 31, 2017 and changes during 2017 are shown in the following table.

	Performance Units		Restricted Stock		Phantom Units	
	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit
			(In millions, except unit data)			
Units outstanding at 12/31/2016	1,969,107	$ 15.27	392,995	$ 20.74	643,604	$ 8.49
Granted [1]	468,626	19.27	—	—	392,338	16.24
Vested [2][3]	(341,507)	29.29	(160,485)	24.86	(21,704)	13.12
Forfeited	(55,819)	14.63	(10,076)	18.74	(26,858)	11.45
Units outstanding at 12/31/2017	2,040,407	13.86	222,434	17.87	987,380	11.38

(1) For performance units, this represents the target number of performance units granted. The actual number of performance units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.

(2) Performance units vested as of December 31, 2017 include 334,682 units from the 2014 annual grant, which vested on June 1, 2017 and paid out at 91.5% of target, or 306,170 units, based on the level of achievement of a performance goal established by the Board of Directors over the performance period.

(3) Performance units outstanding as of December 31, 2017 include 402,586 units from the 2015 annual grant, which were approved by the Board of Directors in 2015. The results of the performance units were certified by the Compensation Committee in February 2018, at a 200% payout based on the level of achievement of a performance goal established by the Board of Directors over a performance period of January 1, 2015 through December 31, 2017. The increase in outstanding units for a payout percentage of an amount other than 100% is not reflected above until the vesting date.

A summary of the Partnership's performance, restricted and phantom units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the year ended December 31, 2017 are shown in the following table.

	December 31, 2017		
	Performance Units	Restricted Stock	Phantom Units
		(In millions)	
Aggregate intrinsic value of units vested	$ 5	$ 2	$ —
Fair value of units vested	10	4	—

Unrecognized Compensation Expense

A summary of the Partnership's unrecognized compensation expense for its non-vested performance units, phantom units and restricted units, and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table.

	December 31, 2017	
	Unrecognized Compensation Cost (In millions)	Weighted Average to be Recognized (In years)
Performance Units	$ 13	1.29
Restricted Units	1	0.43
Phantom Units	6	1.58
Total	$ 20	

As of December 31, 2017, there were 8,662,420 units available for issuance under the long-term incentive plan.

(18) Reportable Segments

The Partnership's determination of reportable segments considers the strategic operating units under which it manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. The accounting policies of the reportable segments are the same as those described in the summary of significant accounting policies described in Note 1. The Partnership uses operating income as the measure of profit or loss for its reportable segments.

The Partnership's assets and operations are organized into two reportable segments: (i) gathering and processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) transportation and storage, which provides interstate and intrastate natural gas pipeline transportation and storage service primarily to natural gas producers, utilities and industrial customers.

Financial data for reportable segments are as follows:

Year Ended December 31, 2017	Gathering and Processing	Transportation and Storage [1]	Eliminations	Total
		(In millions)		
Product sales	$ 1,538	$ 621	$ (506)	$ 1,653
Service revenue	632	525	(7)	1,150
Total Revenues [2]	2,170	1,146	(513)	2,803
Cost of natural gas and natural gas liquids	1,285	604	(508)	1,381
Operation and maintenance, General and administrative	289	179	(4)	464
Depreciation and amortization	232	134	—	366
Taxes other than income tax	37	27	—	64
Operating income	$ 327	$ 202	$ (1)	$ 528
Total assets	$ 9,079	$ 5,616	$ (3,102)	$ 11,593
Capital expenditures	$ 601	$ 113	$ —	$ 714

Year Ended December 31, 2016	Gathering and Processing	Transportation and Storage [1]	Eliminations	Total
		(In millions)		
Product sales	$ 1,081	$ 479	$ (388)	$ 1,172
Service revenue	559	545	(4)	1,100
Total Revenues [2]	1,640	1,024	(392)	2,272
Cost of natural gas and natural gas liquids	915	492	(390)	1,017
Operation and maintenance, General and administrative	276	191	(2)	465
Depreciation and amortization	212	126	—	338
Impairments	9	—	—	9
Taxes other than income tax	32	26	—	58
Operating income	$ 196	$ 189	$ —	$ 385
Total assets	$ 7,453	$ 4,963	$ (1,204)	$ 11,212
Capital expenditures	$ 312	$ 71	$ —	$ 383

Year Ended December 31, 2015	Gathering and Processing	Transportation and Storage [1]	Eliminations	Total
		(In millions)		
Product sales	$ 1,118	$ 590	$ (374)	$ 1,334
Service revenue	545	542	(3)	1,084
Total Revenues [2]	1,663	1,132	(377)	2,418
Cost of natural gas and natural gas liquids	908	565	(376)	1,097
Operation and maintenance, General and administrative	293	230	(1)	522
Depreciation and amortization	195	123	—	318
Impairments	543	591	—	1,134
Taxes other than income tax	30	29	—	59
Operating loss	$ (306)	$ (406)	$ —	$ (712)
Total Assets	$ 7,536	$ 4,976	$ (1,286)	$ 11,226
Capital expenditures	$ 839	$ 110	$ —	$ 949

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(1) Equity in earnings of equity method affiliate is included in Other Income (Expense) on the Consolidated Statements of Income, and is not included in the table above. See Note 9 for discussion regarding ownership interest in SESH and related equity earnings included in the transportation and storage segment for the years ended December 31, 2017, 2016 and 2015.

(2) The Partnership had no external customers accounting for 10% or more of revenues in periods shown. See Note 14 for revenues from affiliated companies.

(19) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data for 2017 and 2016 are as follows:

	Quarters Ended			
	March 31, 2017	June 30, 2017	September 30, 2017	December 31, 2017
	(in millions, except per unit data)			
Total Revenues	$ 666	$ 626	$ 705	$ 806
Cost of natural gas and natural gas liquids	308	279	349	445
Operating income	140	122	137	129
Net income	120	96	113	108
Net income attributable to limited partners	120	95	113	108
Net income attributable to common and subordinated units	111	86	104	99
Basic earnings per unit				
Common units	$ 0.26	$ 0.20	$ 0.24	$ 0.23
Subordinated units [1]	$ 0.25	$ 0.20	$ 0.24	$ —
Diluted earnings per unit				
Common units	$ 0.26	$ 0.20	$ 0.24	$ 0.23
Subordinated units [1]	$ 0.25	$ 0.20	$ 0.24	$ —

	Quarters Ended			
	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016
	(in millions, except per unit data)			
Total Revenues	$ 509	$ 529	$ 620	$ 614
Cost of natural gas and natural gas liquids	195	254	268	300
Operating income	103	57	139	86
Net income	86	39	119	69
Net income attributable to limited partners	86	39	119	68
Net income attributable to common and subordinated units	86	35	110	59
Basic earnings per unit				
Common Units	$ 0.21	$ 0.08	$ 0.26	$ 0.14
Subordinated units	$ 0.20	$ 0.08	$ 0.26	$ 0.14
Diluted earnings per unit				
Common Units	$ 0.19	$ 0.08	$ 0.26	$ 0.14
Subordinated units	$ 0.20	$ 0.08	$ 0.26	$ 0.14

(1) See Note 5 for discussion of the conversion of the subordinated units.

147 FERC ¶ 61,234
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Martha Coakley, Massachusetts Attorney General; Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Company; Associated Industries of Massachusetts; The Energy Consortium; Power Options, Inc.; and the Industrial Energy Consumer Group

Docket No. EL11-66-001

v.

Bangor Hydro-Electric Company; Central Maine Power Company; New England Power Company d/b/a National Grid; New Hampshire Transmission LLC d/b/a NextEra; NSTAR Electric and Gas Corporation; Northeast Utilities Service Company; The United Illuminating Company; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company; Vermont Transco, LLC

OPINION NO. 531

ORDER ON INITIAL DECISION

Issued: June 19, 2014

147 FERC ¶ 61,234
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Acting Chairman;
Philip D. Moeller, John R. Norris,
and Tony Clark.

Martha Coakley, Massachusetts Attorney General; Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Company; Associated Industries of Massachusetts; The Energy Consortium; Power Options, Inc.; and the Industrial Energy Consumer Group

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OPINION NO. 531

ORDER ON INITIAL DECISION

(Issued June 19, 2014)

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Appendix .....

1. This order addresses briefs on and opposing exceptions to an Initial Decision issued on August 6, 2013 by the presiding Administrative Law Judge (Presiding Judge) in the captioned proceeding.[1] The Initial Decision set forth the Presiding Judge's findings concerning a complaint filed pursuant to section 206 of the Federal Power Act (FPA)[2] challenging the New England Transmission Owners' (NETOs)[3] base return on equity (ROE) reflected in ISO New England Inc.'s (ISO-NE) open access transmission tariff (OATT). In this order, we affirm the Initial Decision in part, reverse the Initial Decision in part, announce a new approach we will use for determining the base ROE for public utilities, and establish a paper hearing to allow the participants an opportunity to submit briefs on a limited issue regarding application of this new ROE approach to this proceeding. We also change our practice on post-hearing ROE adjustments.

I. Background

2. The NETOs recover their transmission revenue requirements through formula rates included in ISO-NE's OATT.[4] The revenue requirements for Regional Network Service[5] and Local Network Service[6] that the NETOs provide are calculated using the same single base ROE. On October 31, 2006, the Commission, in Opinion No. 489, established the base ROE at 11.14 percent, which consisted of an initial base ROE of 10.4 percent plus an upward adjustment of 74 basis points to account for changes in

[1] *Martha Coakley, Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, 144 FERC ¶ 63,012 (2013) (Initial Decision).

[2] 16 U.S.C. § 824e (2012).

[3] The NETOs include Bangor Hydro-Elec. Co.; Cent. Me. Power Co.; New England Power Co. d/b/a Nat'l Grid; N.H. Transmission LLC d/b/a NextEra; NSTAR Elect. & Gas Corp.; Ne. Utilities Serv. Co.; United Illuminating Co.; Unitil Energy Systems, Inc. and Fitchburg Gas & Elec. Light Co.; and Vt. Transco, LLC.

[4] ISO-NE's OATT is section II of ISO-NE's Transmission, Markets, and Services Tariff (Tariff). *See* ISO-NE, Tariff, § II.

[5] Regional Network Service is the transmission service over the pool transmission facilities described in Part II.B of the OATT. ISO-NE, Tariff, § I.2 (50.0.0); *see also* ISO-NE, Tariff, § II.B Regional Network Service (0.0.0), *et seq.*

[6] Local Network Service is the network service provided under Schedule 21 and the Local Service Schedules of ISO-NE's OATT. ISO-NE, Tariff, § I.2 (50.0.0); *see also* ISO-NE, Tariff, Schedule 21 Local Service (1.0.0), *et seq.*

capital market conditions that took place between the issuance of the Administrative Law Judge's initial decision in that proceeding and the issuance of Opinion No. 489,[7] as reflected in U.S. Treasury bond yields during that time period.

3. On September 30, 2011, the Complainants[8] filed a complaint alleging that the NETOs' 11.14 percent base ROE is unjust and unreasonable because capital market conditions have significantly changed since that base ROE was established in 2006. The Complainants argued that the bubble in the U.S. housing market, the subsequent financial crisis and economic recession, and the fiscal and monetary policies of the U.S. government have caused a "flight to quality"[9] in the capital markets. The Complainants contended that these market conditions have lowered bond yields and, as a result, capital costs for utilities.[10] The Complainants argued that, as a result, the NETOs' 11.14 percent base ROE now exceeds the level necessary to satisfy the Supreme Court's standards in *Bluefield*[11] and *Hope*.[12] The Complainants asserted that, based on a discounted cash flow (DCF) analysis conducted by their expert witness, the just and reasonable base ROE for the NETOs should not exceed 9.2 percent.

[7] *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006) *order on reh'g*, 122 FERC ¶ 61,265 (2008), *order granting clarification*, 124 FERC ¶ 61,136 (2008), *aff'd sub nom. Conn. Dep't of Pub. Util. Control v. FERC*, 593 F.3d 30 (2010).

[8] Complainants include Martha Coakley, Mass. Attorney Gen.; Conn. Pub. Utilities Regulatory Auth.; Mass. Dept. of Pub. Utilities; N.H. Pub. Utilities Comm'n; Conn. Office of Consumer Counsel; Me. Office of the Pub. Advocate; George Jepsen, Conn. Attorney Gen.; N.H. Office of Consumer Advocate; R.I. Div. of Pub. Utilities and Carriers; Vt. Dept. of Pub. Serv.; Mass. Mun. Wholesale Elec. Co.; Associated Indus. of Mass.; the Energy Consortium; Power Options, Inc.; and the Indus. Energy Consumer Group.

[9] The "flight to quality" refers to investors seeking low-risk investment vehicles.

[10] Complaint, Ex. C-1 at 5-12.

[11] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) (*Bluefield*).

[12] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*).

4. On May 3, 2012, the Commission issued an order on the complaint, establishing hearing and settlement judge procedures.[13] The Hearing Order also set a refund effective date of October 1, 2011. The hearing commenced on May 6, 2012 and was completed on May 10, 2013.[14] In accordance with the hearing's procedural schedule, the participants each first submitted an ROE analysis,[15] based on data from a 6-month study period in 2012,[16] and then filed an updated ROE analysis, using the same DCF methodology that each participant used in its initial analysis but with data based on the 6-month study period from October 2012 through March 2013.

5. On August 6, 2013, the Presiding Judge issued the Initial Decision, finding the NETOs' current 11.14 percent base ROE to be unjust and unreasonable.[17] The Presiding Judge adopted the DCF methodology used by the NETOs and found that it is appropriate to establish two different base ROEs in this proceeding—one for the 15-month refund period from October 1, 2011 (i.e., the refund effective date) to December 31, 2012, and one for the prospective period commencing when the Commission issues its order setting the going-forward base ROE. Thus, the Presiding Judge considered two separate DCF analyses relying on overlapping data from each period, the first using data from May 2012 through October 2012 and the second using data from October 2012 through March 2013. The Presiding Judge found the just and reasonable base ROE for the refund period to be 10.6 percent and the just and reasonable base ROE for the prospective period to be 9.7 percent.[18]

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[13] *Martha Coakley, Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, 139 FERC ¶ 61,090 (2012) (Hearing Order).

[14] The parties conducted settlement negotiations but reached an impasse, leading to termination of the settlement procedures in August 2012. Initial Decision, 144 FERC ¶ 63,012 at P 28.

[15] The following expert witnesses submitted ROE analyses: Dr. William E. Avera, for the NETOs; Ms. Sabina U. Joe, for Trial Staff; Dr. John Wilson, for the EMCOS; and Dr. Randall Woolridge, for the Complainants.

[16] Due to the different due dates for the parties' initial briefs, which ranged from October 2012 to January 2013, each party's initial ROE analysis was based on a different 6-month period in 2012.

[17] Initial Decision, 144 FERC ¶ 63,012 at P 544.

[18] *Id.*

6. The Complainants, Eastern Massachusetts Consumer Owned Systems (EMCOS),[19] the NETOs, and Trial Staff each filed briefs on and opposing exceptions to the Initial Decision.

II. Overview of the Commission's Rulings in this Order

7. In this order, we (1) change our approach on the DCF methodology to be applied in public utility rate cases, (2) apply that approach to the facts of this proceeding to determine the NETOs' base ROE, (3) institute a paper hearing and reopen the record to provide the participants an opportunity to submit briefs on an issue regarding the application of this new DCF approach to the facts of this proceeding, and (4) change our practice on post-hearing ROE adjustments.

8. As discussed in detail below, the Commission has historically applied different DCF methodologies in determining the ROE for public utilities and natural gas and oil pipelines. While there are multiple differences between the two DCF methodologies, the most fundamental difference is that the methodology applied to natural gas and oil pipelines (i.e., the two-step DCF methodology) considers long-term growth projections in estimating a company's cost of equity, whereas the methodology applied to public utilities (i.e., the one-step DCF methodology) considers only short-term growth projections. Based on a review of those methodologies and changes to the electric utility industry since the Commission last considered its electric industry DCF policy, we conclude that it is now appropriate to use the same model for the electric industry as the Commission has used for the natural gas and oil pipeline industries—i.e., use the two-step DCF methodology. We also make a tentative finding that the required long-term growth projection should be based on projected long-term growth in gross domestic product (GDP), but we establish a paper hearing to permit participants to present evidence on that issue.

9. After setting forth our new approach to the electric industry DCF analysis, we then apply the two-step DCF methodology to the facts of this proceeding to produce a proxy group and zone of reasonableness for determining the NETOs' base ROE. While no party proposed using the two-step DCF methodology in this proceeding, there is considerable overlap in the issues that arise under either type of DCF analysis. We find that the NETOs' starting proxy group is consistent with Commission precedent and the record contains all the financial data necessary to conduct a DCF analysis of that proxy group using the two-step DCF methodology, except for a projection of long-term GDP

[19] EMCOS filed a motion to intervene out-of-time on Oct. 1, 2012, and the Presiding Judge granted the motion on Oct. 4, 2012.

growth.[20] Therefore, in order to complete a DCF analysis of the proxy group under the two-step DCF method, we take official notice of the necessary GDP growth projections. Our DCF analysis produces a zone of reasonableness of from 7.03 percent to 11.74 percent. We find it appropriate, based on record evidence, to place the NETOs' base ROE halfway between the midpoint of the zone of reasonableness and the top of that zone. This results in an ROE for the NETOs of 10.57 percent.

10. However, because the participants have not had an opportunity to present evidence on long-term growth rate estimates in this proceeding, we establish a paper hearing and reopen the record to provide that opportunity. Accordingly, our finding concerning the specific numerical just and reasonable ROE for the NETOs is subject to the outcome of the paper hearing on the appropriate long-term growth projection to be used in the two-step DCF methodology.

11. Lastly, based on the record in this proceeding and the economic trends since 2008 more generally, we change our past practice on post-hearing ROE adjustments. Specifically, we end our practice of updating the ROE based on changes in U.S. Treasury bond yields during the proceeding, in light of our shift to the two-step DCF methodology and mounting evidence that U.S. Treasury bond yields are not necessarily a reliable one-for-one indicator of changes in investor-required returns.

12. On balance, we find that our actions in this order, including the shift to the use of the two-step DCF methodology, the placement of the NETOs' base ROE at the midpoint of the upper half of the zone of reasonableness, and the elimination of the post-hearing adjustment based on U.S. Treasury bonds, taken together produce a base ROE that reasonably balances investor and consumer interests consistent with *Hope* and *Bluefield* and allow just and reasonable rates for consumers and transmission owners.[21]

III. Adopting the Two-Step, Constant Growth DCF Methodology for Public Utilities

13. The Complaint filed in this proceeding argues that, based on the DCF methodology the Commission currently uses in public utility rate cases, the existing base

[20] We adopt the work papers provided by the NETOs' witness, Dr. Avera, including his stock prices, dividends, and IBES short-term growth projections, as the appropriate inputs for the dividend yield calculations using the two-step DCF methodology.

[21] *See, e.g., Hope*, 320 U.S. at 603.

ROE for electric transmission service is too high, and thus unjust and unreasonable.[22] Other pending complaints before the Commission echo the same theme.[23] At the same time, the NETOs have assailed the Commission's existing electric DCF methodology as failing to produce adequate returns.[24] In light of the concerns raised by both transmission customers and transmission owners, the Commission has reviewed its DCF analysis used in determining public utility ROEs. For the reasons discussed below, we find that the ROE in this proceeding, as well as in future public utility cases,[25] should be based on the same DCF methodology the Commission has used in natural gas pipeline and oil pipeline cases for many years—the two-step, constant growth DCF methodology, or two-step DCF methodology.

[22] Complaint at 25-26.

[23] *See, e.g.*, Environment Northeast, *et al.*, Complaint, Docket No. EL13-33-000 (filed Dec. 27, 2012); Seminole Electric Cooperative, Inc. and Florida Municipal Power Authority, Complaint, Docket No. EL12-39-000 (filed Feb. 29, 2012); Seminole Electric Cooperative, Inc. and Florida Municipal Power Authority, Complaint, Docket No. EL13-63-000 (filed May 13, 2013); Golden Spread Electric Cooperative, Inc., Complaint, Docket No. EL12-59-000 (filed Apr. 20, 2012); Golden Spread Electric Cooperative, Inc., Complaint, Docket No. EL13-78-000 (filed Jul. 19, 2013); Grand Valley Rural Power Lines, *et al.*, Complaint, Docket No. EL12-77-000 (filed Jun. 21, 2012); Grand Valley Rural Power Lines, *et al.*, Complaint, Docket No. EL13-86-000 (filed Aug. 30, 2013); New York Association of Public Power, Complaint, Docket No. EL12-101-000 (filed Sept. 11, 2012); Municipal Electric Association of New York, Complaint, Docket No. EL13-16-000 (filed Nov. 2, 2012); New York Association of Public Power, Complaint, Docket No. EL14-29-000 (filed Feb. 6, 2014); Delaware Division of the Public Advocate, *et al.*, Complaint, Docket No. EL13-48-000 (filed Feb. 27, 2013); Frankford Electric & Water Plant Board, *et al.*, Complaint, Docket No. EL14-5-000 (filed Oct. 17, 2013); and ABATE, *et al.*, Complaint, Docket No. EL14-12-000 (filed Nov. 12, 2013).

[24] *See, e.g.*, NETOs Brief on Exceptions at 36..

[25] We consider that this group includes all currently pending ROE-related complaint cases in which the Commission has not issued a final order. In cases which have already been set for hearing, the Presiding Judge should modify the procedural schedule as necessary to provide the participants an opportunity to present evidence relevant to the application of the two-step DCF methodology.

14. For over 30 years, the Commission has based ROEs on the rate of return required by investors to invest in a company – otherwise known as the capital attraction rate of return, or the market cost of equity capital. Over this period, the Commission has relied primarily on the DCF model to provide an estimate of the investors' required rate of return.[26] The underlying premise of the DCF model is that an investment in common stock is worth the present value of the infinite stream of dividends discounted at a market rate commensurate with the investment's risk.[27]

15. With simplifying assumptions, the formula for the DCF model reduces to: P = D/k-g, where "P" is the price of the common stock, "D" is the current dividend, "k" is the discount rate (or investors' required rate of return), and "g" is the expected growth rate in dividends. For ratemaking purposes, the Commission rearranges the DCF formula to solve for "k", the discount rate, which represents the rate of return that investors require to invest in a company's common stock, and then multiplies the dividend yield by the expression (1+.5g) to account for the fact that dividends are paid on a quarterly basis. Multiplying the dividend yield by (1+.5g) increases the dividend yield by one half of the growth rate and produces what the Commission refers to as the "adjusted dividend yield." The resulting formula is known as the constant growth DCF model and can be expressed as follows: k=D/P (1+.5g) +g.

16. While the DCF model has been employed for decades, it has nonetheless continued to generate controversy. In response, the Commission has, over the years, made changes in its implementation of the model with respect to the industries it regulates. In making these changes, the Commission's application of the DCF model to public utilities now diverges significantly from the Commission's application of the model to natural gas and oil pipelines. As discussed in more detail below, the Commission uses a one-step DCF methodology for public utilities and a two-step DCF methodology for natural gas and oil pipelines. The difference in the naming conventions for the two methodologies stems from the growth rate projections used in each: the one-

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[26] The Commission first took cognizance of the DCF methodology in public utility cases as far back as the 1970's. *See, e.g., Minn. Power and Light Co.*, 3 FERC ¶ 61,045, at 61,132-33 (1978) ("We are interested in forward looking analyses of the market's required rates of return. The Commission seeks to have before it estimates of the opportunity cost of equity capital in capital markets to use in making rate of return determinations. Market oriented techniques, including the DCF approach, are useful in this regard.").

[27] *See, e.g., Canadian Ass'n of Petroleum Producers v. FERC*, 254 F.3d 289, 293 (D.C. Cir. 2001) (*CAPP v. FERC*).

step DCF methodology is based only on short-term growth projections, while the two-step DCF methodology considers both short-term and long-term growth projections.

A. Two-Step DCF Methodology

17. The Commission developed the two-step DCF methodology used for determining the cost of capital for individual gas and oil pipelines in a series of orders during the mid-1990s. Under that methodology, the Commission determines a single cost of equity estimate for each member of a proxy group. For the dividend yield component of the DCF model, the Commission derives a single, average dividend yield based on the indicated dividend and the average of the monthly high and low stock prices over a six-month period.[28] The Commission uses a two-step procedure for determining the constant dividend growth component of the model, averaging short-term and long-term growth estimates. Security analysts' five-year forecasts for each company in the proxy group, as published by the Institutional Brokers Estimate System (IBES), are used for determining growth for the short term; earnings forecasts made by investment analysts are considered to be the best available estimates of short-term dividend growth because they are likely relied on by investors when making their investment decisions.[29] Long-term growth is based on forecasts of long-term growth of the economy as a whole, as reflected in GDP.[30] The short-term forecast receives a two-thirds weighting and the long-term forecast receives a one-third weighting in calculating the growth rate in the DCF model.[31]

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[28] *See, e.g., Portland Natural Gas Transmission Sys.*, Opinion No. 510, 134 FERC ¶ 61,129, at PP 232-34 (2011).

[29] *See, e.g., Transcon. Gas Pipe Line Corp*., Opinion No. 414-B, 85 FERC ¶ 61,323, at 62,269 & n.34 (1998) (which cites an article entitled "Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return" in *Financial Management*, Spring 1986, pages 58-67); *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶ 61,048, at PP 73-77 (2008) (*Proxy Group Policy Statement*).

[30] *Nw. Pipeline Corp*., Opinion No. 396-B, 79 FERC ¶ 61,309, at 62,383 (1997) *Williston Basin Interstate Pipeline Co.*, 79 FERC ¶ 61,311, at 62,389 (1997), *aff'd in relevant part sub nom. Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d 54, 57 (D.C. Cir. 1999).

[31] *Transcon. Gas Pipe Line Corp*., Opinion No. 414-A, 84 FERC ¶ 61,084, at 61,423-24, *reh'g denied*, Opinion No. 414-B, 85 FERC ¶ 61,323, at 62,266-70 (1998), *aff'd*, *CAPP v. FERC*, 254 F.3d 289.

18. The Commission first required a two-step method for determining constant growth of dividends in natural gas pipeline cases in 1994, in *Ozark Gas Transmission System*, 68 FERC ¶ 61,032 (1994) (*Ozark*). In *Ozark*, the Commission held that the constant growth DCF model that the Commission uses requires consideration of long-term growth projections. The Commission explained:

> In the constant growth DCF model used by both parties in this proceeding, dividends are expected to grow indefinitely at the rate of (g). The indefinite future used by the DCF model is 50 years or more. . . . While we concede that it is more difficult to project growth for many years from the present time, we conclude that a projection limited to five years, with no evidence of what is anticipated beyond that point, is not consistent with the DCF model and cannot be relied on in a DCF analysis.[32]

19. The Commission also pointed out that, in its 1983 decision adopting the constant growth DCF model for gas pipeline cases, the Commission had cautioned that "we cannot simply adopt, without further consideration, calculations of past dividend growth or projections by investment advisory services of growth for relatively short periods of years into the future."[33] Thus, the Commission in *Ozark* reversed the Presiding Judge's sole reliance on five-year growth projections for the DCF analysis, finding that "the five-year projections are not of themselves incorrect, but merely limited to too brief a time period to meet the requirements of the DCF model."[34]

20. Following *Ozark*, debate ensued in natural gas pipeline cases over the best way to estimate the long-term growth of pipeline dividends. In Opinion No. 396-B, issued in 1997, the Commission found that none of the proposed natural gas industry-specific projections of long-term growth were reliable.[35] Instead, the Commission held that the long-term growth in the United States economy as a whole, as measured by GDP, is the

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[32] *Ozark*, 68 FERC at 61,105. The Commission chose 50 years to represent the indefinite future because the present value of a one-dollar dividend received 50 years in the future and discounted at 12 percent is less than one cent. *Id.* at n.32.

[33] *Consol. Gas Supply Corp.*, 24 FERC ¶ 61,046, at 61,146 (1983).

[34] *Ozark*, 68 FERC at 61,107.

[35] The proposed industry-specific projections included projections of the growth of natural gas consumption and the growth of natural gas prices.

most reasonable measure to use as the long-term growth measure for a DCF analysis.[36] The Commission stated, "[i]t is reasonable to expect that, over the long-run, a regulated firm will grow at the rate of the average firm in the economy, because regulation will generally prevent the firm from being extremely profitable during good periods, but also protects it somewhat during bad periods."[37] The D.C. Court of Appeals affirmed the Commission's decision to use GDP to estimate long-term growth in dividends, finding that "[t]he testimony adduced at the hearing demonstrated that major investment houses used an economy-wide approach to project long-term growth, that such an approach was supported by practical economic considerations, and that existing industry-specific approaches imperfectly reflected investor expectations and made unfounded economic assumptions."[38]

21. When the Commission first required use of a long-term growth estimate, the Commission simply averaged the short-term five-year IBES growth estimate with the long-term GDP growth estimate in determining the overall dividend growth rate.[39] However, in 1998, in Opinion No. 414-A, the Commission changed the weighting scheme in order to give two-thirds weight to short-term forecasts and one-third weight to long-term forecasts. The Commission explained,

> While determining the cost of equity nevertheless requires that a long-term evaluation be taken into account, long-term projections are inherently more difficult to make, and thus less reliable, than short-term projections. Over a longer period, there is a greater likelihood for unanticipated developments to occur affecting the projection. Given the greater reliability of the short-term projection, we believe it is appropriate to give it greater weight. However, continuing to give some effect to the long-term growth projection,

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[36] Opinion No. 396-B, 79 FERC at 62,382-83, *reh'g denied*, Opinion No. 396-C, 81 FERC ¶ 61,036 (1997).

[37] *Id.*

[38] *Williston Basin Interstate Pipeline Co., v. FERC*, 165 F.3d 54, 64 (D.C. Cir. 1999). Nonetheless, finding the record evidence inadequate to support the Commission's use of certain GDP data, the Court remanded the case for further proceedings on this issue. Subsequently, the Commission has used an average of three GDP growth projections.

[39] Opinion No. 396-B, 79 FERC at 62,383, *reh'g denied*, Opinion No. 396-C, 81 FERC ¶ 61,036 (1997).

> will aid in normalizing any distortions that might be reflected in short-term data limited to a narrow segment of the economy.[40]

22. The United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) affirmed this two-thirds/one-third weighting for determining the overall dividend growth estimate.[41] Since Opinion No. 414-A, the Commission has made no changes in its two-step DCF methodology used for natural gas and oil pipelines, except to require that, if a master limited partnership (MLP) is included in the proxy group, its long-term growth rate should be one-half the GDP growth estimate.[42] The Commission explained that MLPs have less growth potential than corporations, because they generally distribute to partners an amount in excess of their reported earnings.[43]

23. After the Commission derives a single cost of equity estimate for each member of a natural gas or oil pipeline proxy group, the zone of reasonableness is defined by the low and high estimates of the market cost of equity for the members of the proxy group.

B. One-Step DCF Methodology

24. While the Commission also uses a constant growth DCF model to determine public utility ROEs, the Commission uses a one-step DCF methodology, which differs in numerous ways from the two-step DCF methodology it uses for natural gas and oil pipelines. First, instead of determining a single cost of equity estimate for each proxy company, the one-step DCF methodology determines separate high and low estimates for each proxy company. This is done as follows.

25. First, the Commission calculates two dividend yields for each proxy company – a low average dividend yield and a high average dividend yield, with both averages based on high and low stock prices for each of the six months in the study period. Next, the Commission makes two estimates of dividend growth. One is based on the same IBES analyst five-year growth forecasts used for the short-term growth projection in the two-step DCF methodology. The other is based on the "br + sv" sustainable growth formula, where "b" represents the percentage of earnings expected to be retained (after the payment of dividends), "r" represents the expected rate of return on book equity, "s"

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[40] Opinion No. 414-A, 84 FERC at 61,423-24.

[41] *CAPP v. FERC*, 254 F.3d at 297.

[42] *Proxy Group Policy Statement*, 123 FERC ¶ 61,048 at P 106.

[43] *Id.* P 12.

represents the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate. The "br" component of this formula projects a utility's growth from the investment of retained earnings, and the "sv" component estimates growth from external capital raised by the sale of additional stock.[44] For each input in the "br + sv" formula, the Commission uses an average of the estimates published in *Value Line* for the current year, the next year, and three- to five-years in the future.[45]

26. The low cost of equity estimate for each proxy company is determined by adding the lower of the two growth projections for that company to the low dividend yield. The high cost of equity estimate for each company is determined by adding the higher of the two growth estimates for that company to the high dividend yield.[46] If the proceeding involves a group of electric utilities, the Commission uses the lowest of the proxy company low estimates to determine the bottom of the range of reasonable returns and the highest of the proxy company high estimates to determine the top of the range and then generally sets the base ROE for the group at the midpoint of the range. If the proceeding involves a single company, the Commission averages the high and low cost of equity estimates of each proxy company, and sets the ROE for the electric utility at the median value of the range of reasonable returns.[47]

27. The most significant difference between the one-step and two-step DCF methodologies is the lack of a long-term growth projection in the one-step DCF methodology. After the Commission held in *Ozark* that the DCF model requires use of a long-term growth projection in natural gas pipeline cases, the issue arose whether the Commission should also modify its electric DCF methodology to include a long-term growth projection. In 1999, in an Initial Decision involving Southern California Edison Company, [48] the Presiding Judge adopted a two-step DCF formula with a long-term growth projection for a public utility, because he found it consistent with the

[44] However, in the absence of reliable record evidence on expected common stock issuances, the "sv" component is generally considered to be zero.

[45] *See S. Cal. Edison Co.*, 92 FERC ¶ 61,070, at 61,263 (1999).

[46] *Id.* at 61,264; *see also Appalachian Power Co.*, 83 FERC ¶ 61,335, at 62,350 (1998).

[47] *S. Cal. Edison Co. v. FERC*, 717 F.3d 177, 183-87 (D.C. Cir. 2013).

[48] *S. Cal. Edison Co.*, 86 FERC ¶ 63,014 (1999).

Commission's recent precedent in natural gas pipeline cases.[49] In contrast to the approach taken in natural gas and oil pipeline cases, the Commission had consistently applied a one-step, constant growth DCF model for determining allowed ROEs for public utilities.[50] On September 17, 1999, in response to exceptions taken to the Initial Decision on how best to determine the allowed ROE for Southern California Edison Company, the Commission issued an "Order Establishing Further Proceedings on Issue of Rate of Return on Common Equity."[51]

28. Based on a review of the record developed in the reopened proceeding, the Commission issued Opinion No. 445, which reversed the Initial Decision and found that the time was not ripe to apply the two-step DCF methodology in public utility cases.[52] The Commission stated that, up until that time, it had not expressly addressed the differing approaches taken in determining the allowed ROE in natural gas/oil pipeline and public utility cases. The Commission in Opinion No. 445 then compared the two industries and concluded "that significant differences exist in the electric utility industry and the natural gas pipeline industry which warrant the continued use of different growth rates in the DCF models for each."

29. The Commission explained that the electric industry was just beginning a significant new phase of its restructuring, while the gas pipeline industry had nearly completed its major restructuring when Opinion No. 396-B was issued in 1997.[53] In particular, at the time of its filing, Southern California Edison Company had just begun to

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[49] *Id.* at 65,143 (citing *Williston Basin Interstate Pipeline Co.*, 50 FERC ¶ 61,284 (1990), *vacated on other grounds*, 931 F.2d 948 (D.C. Cir. 1991); Opinion No. 396-B, 79 FERC ¶ 61,309, *reh'g denied*, Opinion No. 396-C, 81 FERC ¶ 61,036; and *Transcon. Gas Pipe Line Corp.*, Opinion No. 414, 80 FERC ¶ 61,157 (1997), *order on reh'g*, Opinion No. 414-A , 84 FERC ¶ 61,084.

[50] *See, e.g., Consumers Energy Co.*, 85 FERC ¶ 61,100 (1998); *Sw. Pub. Serv. Co.*, 83 FERC ¶ 61,138 (1998); *Appalachian Power Co.*, 83 FERC ¶ 61,335; *Jersey Cent. Power & Light Co.*, Opinion No. 408, 77 FERC ¶ 61,001 (1996); *S. Cal. Edison Co.*, 56 FERC ¶ 61,003, *order on reh'g*, 56 FERC ¶ 61,117 (1991); *Conn. Light & Power Co.*, Opinion No. 305, 43 FERC ¶ 61,508 (1988).

[51] *S. Cal. Edison Co.*, 88 FERC ¶ 61,254 (1999).

[52] *S. Cal. Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070, at 61,261 (2000).

[53] *Id.*

restructure from a vertically integrated utility.[54] Indeed, with the electric industry in flux and the future so uncertain, it seemed too speculative to assume that investors were reflecting long-term growth estimates in their investment decisions.

30. In addition, the Commission observed that there was a significant difference in the short-term growth rates between Southern California Edison Company and gas pipeline companies versus GDP growth rates. While the short-term growth rates of natural gas pipeline proxy group companies were all significantly higher than the projected growth in GDP, that was not true for public utilities.[55] The Commission attributed this difference to the higher dividend payout ratios of public utilities, which produce lower growth from retained earnings, and the resulting lower dividend growth.[56] With such a wide gap between short-term and long-term natural gas pipeline growth rates, the implication was that the two-step DCF methodology was better suited to the natural gas pipeline industry than to the electric utility industry because the short-term dividend growth rates for public utilities did not deviate significantly from GDP rates.

31. Moreover, the record in the Opinion No. 445 proceeding contained evidence that two large investment firms use the long-term growth of the economy as a whole in their analyses of natural gas pipeline companies, while one of them indicated that it treated electric utilities differently from all of the other industrial companies when estimating growth rates.[57] For all of these reasons, the Commission found that it would be "premature" at that time to incorporate a GDP estimate in the DCF methodology applicable to an electric utility company.[58] Therefore, the Commission calculated the ROE for Southern California Edison Company using the one-step, constant growth DCF methodology and has continued to use this approach in electric utility cases.

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[54] *Id.*

[55] *S. Cal. Edison Co.*, 92 FERC at 61,261 (citing *Ozark*, 68 FERC at 61,104-05 (growth estimates ranging from 8.81 percent to 15.2 percent and GDP estimates of 5.4 percent)); *Williston Basin Interstate Pipeline Co.*, 72 FERC ¶ 61,074, at 61,387 (growth estimates ranging from 8 to 15 percent and GDP estimates of 5.37 percent and 6.33 percent); Opinion No. 414-A, 84 FERC ¶ 61,084 at Appendix A (growth estimates ranging from 8 percent to 15 percent and a GDP estimate of 5.45 percent).

[56] Opinion No. 445, 92 FERC at 61,262.

[57] *Id.*.

[58] *Id.*

Significantly, though, the Commission added that "[s]hould circumstances in the industry change, in the future, we will reevaluate our methodology, as necessary."[59]

C. Adoption of the Two-Step DCF Methodology for Public Utility Rate Cases

32. This proceeding has caused the Commission to revisit its historical use of DCF analyses to determine the allowed ROE in public utility cases, given the evolution of the electric industry since issuance of Opinion No. 445. Based on this review, the Commission finds that it is now appropriate to change the way DCF analyses are conducted in public utility cases to use the same methodology as the Commission uses in natural gas and oil pipeline cases. In theory, an analytical tool such as the DCF model is equally applicable to all companies, whether they are public utilities, natural gas pipeline companies, or oil pipeline companies.

33. The DCF model is based on the premise that an investment in common stock is worth the present value of the infinite stream of future dividends discounted at a market rate commensurate with the investment's risk. Corporations have indefinite lives and therefore will pay dividends for an indefinite period. For that reason, the Commission stated as long ago as 1983, when it first adopted the constant growth DCF model for gas pipeline cases, that "projections by investment advisory services of growth for relatively short periods of years into the future"[60] cannot be relied on "without further consideration." Thus, as the Commission held in *Ozark*, the constant growth DCF model requires consideration of long-term growth projections.

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[59] *Id.* In Opinion No. 446, the Commission similarly rejected a proposal to use the two-step DCF methodology for a public utility, for essentially the same reasons as in Opinion No. 445. *Sys. Energy Resources, Inc.*, Opinion No. 446, 92 FERC ¶ 61,119, at 61,443-46 (2000). In addition, the Commission stated that use of the two-step DCF methodology could overcompensate the public utility for its cost of equity. The Commission pointed out that the internal growth rate of public utilities averaged only 2.51 percent during the 1993-1997 period and was projected to be 3.86 percent in 2002, as compared to 20-year GDP growth projections in that case of 5.0 and 5.2 percent (and in contrast to natural gas pipeline growth rates that exceeded GDP). The Commission attributed these low internal growth rates to public utilities' high dividend payout ratios, and stated that combining a public utility's high dividend yield with growth rates reflecting the projected growth in GDP could overestimate the utility's cost of capital.

[60] *Consol. Gas Supply Corp.*, 24 FERC at 61,105.

34. Both growth projections used in the existing one-step DCF methodology rely on growth projections by investment advisory services for relatively short periods of years. The IBES growth projections are for only five years. While the "br + sv" growth formula used in public utility rate cases seeks to estimate a company's sustainable growth, it relies on short-term *Value Line* projections of the various inputs to the formula for the current year, the next year, and a year three- to five-years in the future. For that reason, the Commission has previously held that the "br + sv" formula only produces a projection of short-term growth, similar to the IBES projections.[61] Thus, the one-step DCF methodology does not include a long-term growth projection of the type ordinarily required by the constant growth DCF model.

35. When, in 2000, the Commission nevertheless decided not to adopt the two-step DCF methodology in the Opinion No. 445 proceeding, an important consideration was the fact that Southern California Edison Company and other public utilities were only just beginning the process of restructuring. Given the anticipated changes in the industry at that time, it did not seem to be an appropriate time to reflect an estimate of long-term growth in dividends in the DCF model. In those circumstances, the Commission's view was that investors would be unlikely to place much weight on long-term forecasts because the uncertainties regarding the future were so great.[62] Regulatory change is an inevitable part of any regulated industry. However, the investor uncertainty due to the type of changes anticipated in 2000 has diminished.

36. Therefore, we now believe that the time has come to apply the DCF methodology in public utility cases in a manner more consistent with the way it is applied in natural gas and oil pipeline cases. Most importantly, including a long-term estimate of dividend growth in the constant growth DCF model, as is done in natural gas/oil pipeline cases, will now bring the public utility ROE approach into full alignment with the underlying theory of the DCF model.[63]

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[61] *Proxy Group Policy Statement*, 123 FERC ¶ 61,048 at P 100 (citing Opinion No. 445, 92 FERC at 61,262-3).

[62] Opinion No. 445, 92 FERC at 61,261-61,262.

[63] Incorporating a long-term growth estimate in the DCF methodology is consistent with the underlying theory of the constant growth DCF model because

> from the standpoint of the DCF model that extends into perpetuity, analysts' horizons are too short, typically five years. It is often unrealistic for such growth to continue in perpetuity. A transition must occur between the first stage of growth forecast by analysts for the first five years and the

(continued…)

37. In addition, the Commission believes that developing a zone of reasonableness pursuant to the two-step DCF methodology with its use of a single cost of equity estimate for each proxy company is less likely to produce the anomalous results that can result from combining high and low dividend yields with high and low short-term projections of dividend growth to produce two estimates for each proxy company. For example, to the extent a high DCF estimate is based on an IBES five-year projection, that result is inconsistent with the theory underlying the constant growth DCF model, which requires an estimate of dividend growth extending into the indefinite future. Moreover, the purpose of the sustainable "br + sv" growth estimate is to act as a check on the reasonableness of IBES forecasts. In practice, however, the two growth rates are used independently to establish high and low estimates of the cost of equity for electric utilities. The end result is often a zone of reasonableness that is defined by two widely divergent growth rates that do not engender much confidence in the reliability of the estimates.

38. The Commission recognizes that the IBES growth projections of electric utilities continue to reflect a different pattern from those of natural gas and oil pipelines. While pipeline IBES growth projections are consistently higher than projections of long-term growth in GDP growth, that is not true of public utilities. For example, the IBES growth projections for the national proxy group we adopt in this case range from 2.0 percent to 8.10 percent, as compared to long-term projected growth in GDP of 4.39 percent.[64] However, we no longer believe the generally lower IBES short-term growth projections of public utilities justify not including a long-term growth projection in the DCF analysis of electric utilities. As the Commission stated in Opinion No. 414-A, giving "some effect to the long-term growth projection will aid in normalizing any distortions that might be reflected in short-term data limited to a narrow segment of the economy."[65] This is true, regardless of whether the short-term growth projection is greater or less than the growth in the economy as a whole. Over the long-run, a regulated firm may reasonably be expected to grow at the rate of the average firm in the economy; growth either

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> company's long-term sustainable growth rate. . . . It is useful to remember that eventually all company growth rates, especially utility services growth rates, converge to a level consistent with the growth rate of the aggregate economy.

Roger A. Morin, New Regulatory Finance 308 (Public Utilities Reports, Inc. 2006).

[64] Moreover, four public utilities, which we are excluding from the proxy group in this case, have negative IBES growth projections.

[65] Opinion No. 414-A, 84 FERC at 61,423.

significantly above or below the growth of the economy as a whole is unlikely to continue indefinitely. Using the same long-term growth projection for all public utilities is consistent with this expectation. It also produces a narrower zone of reasonableness, consistent with the fact different firms in a regulated industry would not ordinarily be expected to have widely varying levels of profitability.

39. Therefore, in this proceeding, and in future public utility cases, the Commission will adopt the same two-step DCF methodology used in natural gas and oil pipeline cases.[66] In other words, there will be a single, six-month average dividend yield for each company in the proxy group. More importantly, the estimate of the dividend growth rate for each company in the proxy group will now include a short-term projection of dividend growth (with a two-thirds weight) and a long-term projection of dividend growth (with a one-third weight). The short-term growth estimate will be based on the five-year projections reported by IBES (or a comparable source). Given the absence of an electric industry-specific long-term growth projection that reasonably reflects investor expectations, the long-term growth estimate will be based on an average of the GDP growth rates that have been relied on in gas and oil pipeline cases.[67]

40. We also find that it is reasonable to expect that public utilities, which transmit electricity to supply energy to the national economy, will sustain growth consistent with the growth of the economy as whole.[68] This conclusion is buttressed by the fact that the current three to five year projected internal growth rate of electric utilities approximates the projected growth in GDP. The median internal growth rate of the 41 electric utilities in the proxy group before application of the low-end outlier test is 4.32 percent, and the midpoint internal growth rate for those utilities is 4.55 percent.[69] These growth rates are

[66] As noted *supra* at n.25, the Commission will apply the two-step methodology to all pending ROE-related complaint cases, including those that have been set for hearing.

[67] In Opinion No. 396-B, the Commission based the GDP growth rate on forecasts made by the Energy Information Administration (EIA), DRI/McGraw Hill, and Wharton Economic Forecasting Associates (Wharton). Opinion No. 396-B, 79 FERC at 62,384-62,385. Over time, however, the sources of GDP data have changed. Currently, the Commission uses GDP data from EIA, Social Security Administration, and IHS Global Insight (which was formed by the merger of DRI/McGraw Hill and Wharton). *See Portland Natural Gas Transmission Sys.*, 137 FERC ¶ 63,018, at PP 121-128 (2011), *aff'd in relevant part*, Opinion No. 524, 142 FERC ¶ 61,197 at PP 317-320.

[68] *See supra* n.63.

[69] *See* Ex. NET-703.

very close to the 4.39 percent projected long-term growth in GDP. While the Commission, in Opinion No. 446, declined to apply the two-step DCF methodology to public utilities based in part of the fact their internal growth rates were less than GDP, that disparity no longer exists.[70] In Opinion No. 446, the Commission explained that the two-step DCF methodology could overcompensate a public utility for its cost of equity because GDP was approximately double the internal grow rates of the companies analyzed in that proceeding.[71] Because public utilities' internal growth rates now approximate GDP, incorporating GDP into public utilities' cost of equity estimates will not overcompensate those utilities. For this reason, the Commission no longer sees a reason to use a long-term growth projection for public utilities that is less than the projected long-term growth of GDP.

41. For the reasons discussed above, the Commission concludes that using, in public utility cases, the same formulation of the DCF model used for natural gas/oil proceedings is consistent with the underlying theory of the DCF model and is preferable to the one-step DCF methodology. However, we also understand that any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market conditions. Therefore, while the DCF model remains the Commission's preferred approach to determining allowed rate of return, the Commission may consider the extent to which economic anomalies may have affected the reliability of DCF analyses in determining where to set a public utility's ROE within the range of reasonable returns established by the two-step constant growth DCF methodology.

D. Implementation of the Two-Step DCF Methodology in This Case

42. While the NETOs raised concerns at the hearing in this case as to whether the Commission's existing electric DCF analysis accurately reflects investor expectations, no participant in the hearing proposed to use the two-step DCF methodology. Thus, the participants have not had an opportunity to present evidence on issues raised by implementation of the two-step constant growth method that do not arise under our existing electric DCF methodology. However, there is considerable overlap in the issues that arise when conducting either type of DCF analysis, and all of the financial evidence necessary to apply the two-step DCF methodology in this case is in the evidentiary record developed at the hearing, with the exception of necessary GDP growth projections.

[70] *See* Opinion No. 446, 92 FERC at 61,443-61,446.

[71] *Id.*, *supra* n. 59.

43. For the reasons provided above, we find that the NETOs' ROE to be established in this case should be determined using the two-step DCF methodology. Based on the extensive record developed at the hearing in this case, together with taking official notice of the appropriate long-term GDP growth projections, we will make tentative findings in this order, based on the record thus far in this proceeding, concerning whether the NETOs' existing base ROE is unjust and unreasonable and what the just and reasonable ROE for the NETOs is under the two-step DCF methodology. However, as discussed below, we will reopen the record for the limited purpose of allowing the participants to this proceeding an opportunity to present written evidence concerning issues unique to the application of the two-step DCF methodology to the facts of this proceeding. Specifically, this will give the participants an opportunity to present evidence concerning the appropriate long-term growth projection to be used for public utilities under the two-step DCF methodology. As discussed in more detail below, we find that the participants have had ample opportunity to litigate all other issues in this proceeding and, therefore, will not entertain those issues in the paper hearing. After reviewing the pleadings submitted during the paper hearing, we will make a final determination of the NETOs' just and reasonable base ROE.

IV. Burden of Proof

A. Initial Decision

44. The Presiding Judge found that the Complainants and Trial Staff hold the burden to establish that the current ROE is unjust and unreasonable, and that they have met that burden in this case.[72] The Presiding Judge rejected the NETOs' argument that the existing base ROE should be retained because it falls within the zone of reasonableness of the DCF analyses, explaining that "a bright line litmus test of this sort" is contrary to Commission precedent and illogical when applied to the facts of this case.[73] The Presiding Judge found that the Commission has previously rejected this argument in *Bangor Hydro*.[74] The Presiding Judge further explained that all of the evidence in this case supports the finding that the existing 11.14 percent base ROE is no longer just and reasonable.

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[72] Initial Decision, 144 FERC ¶ 63,012 at P 546.

[73] *Id.* P 547.

[74] *Id.* P 547 (citing *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,038 (2008) (*Bangor Hydro*)).

B. Briefs on Exceptions

45. The NETOs argue both that the Complainants have the burden to show that the existing base ROE is unjust and unreasonable, and that the Commission does not have statutory authority to change the existing base ROE unless the evidence shows that it is entirely outside the zone of reasonableness. The NETOs assert that the Complainants have not met this burden. The NETOs further contend that the Initial Decision did not acknowledge or examine the Commission and court precedent on this issue—specifically, *City of Winnfield* and *Texas Eastern*.[75] The NETOs argue that the Initial Decision also overlooks years of case law that links the zone of reasonableness to the determination of whether a rate is just and reasonable,[76] and relies on only one case *Bangor Hydro*, which is both distinguishable and contrary to D.C. Circuit precedent.[77] The NETOs further contend that the principle that rates have to be outside the zone of reasonableness to be unjust and unreasonable is also recognized under the Interstate Commerce Act.[78]

C. Briefs Opposing Exceptions

46. According to Trial Staff, all parties agree that the Initial Decision correctly determined that the parties challenging the existing base ROE bear the burden of showing that it is unjust and unreasonable. Trial Staff further asserts that the Initial Decision properly determined that the burden has been met in this case. Trial Staff, the Complainants, and EMCOS state that the Commission is not required to accept an ROE merely because it falls within the zone of reasonableness, and the Commission already rejected the NETOs' argument to the contrary in *Bangor Hydro*. EMCOS state that the Initial Decision correctly follows *Bangor Hydro* in finding that the determination of a just

[75] NETOs Brief on Exceptions at 10-11 (citing *City of Winnfield v. FERC*, 744 F.2d 871 (D.C. Cir. 1984) (*City of Winnfield*); *Texas Eastern Transmission Corp.*, 32 FERC ¶ 61,056 at 61,150, n.6 (1985) (*Texas Eastern*)).

[76] NETOs Brief on Exceptions at 13-15 (citing *Me. Pub. Utilities Comm'n v. FERC*, 520 F.3d 464, 470-471 (D.C. Cir. 2008), *rev'd in part on other grounds sub nom. NRG Power Mktg., LLC v. Me. Pub. Utilities Comm'n*, 558 U.S. 165 (2010); *Calpine Corp. v. Cal. Indep. Sys. Op. Corp.*, 128 FERC ¶ 61,271, at P 41 (2009); *Cal. Indep. Sys. Op. Corp.*, 140 FERC ¶ 61,168, at P 17 (2012); *Montana-Dakota Utils. Co. v. Nw. Pub. Serv. Co.*, 341 U.S. 246, 251 (1951) (*Montana-Dakota*)).

[77] NETOs Brief on Exceptions at 19 (citing *Bangor Hydro*, 122 FERC ¶ 61,038).

[78] *Id.* at n.16 (citing *Lakehead Pipe Line Co., Ltd. P'ship,* 65 FERC ¶ 63,021, at 65,137 (1993)).

and reasonable ROE does not turn on whether the ROE falls within the zone of reasonableness, but instead requires a balancing of interests that reflects the unique circumstances of each case.[79]

47. The Complainants and EMCOS contend that the NETOs' argument contradicts controlling judicial precedent,[80] and is unsupported by *City of Winnfield* and *Texas Eastern*.[81] Similarly, Trial Staff asserts that the Presiding Judge properly considered *City of Winnfield* and *Texas Eastern*, as well as other relevant case law, in rejecting the NETOs' argument.[82] Trial Staff contends that *City of Winnfield* involved an FPA section 205 proceeding in which the court's discussion of FPA section 206 is dicta, and asserts that *Texas Eastern* is distinguishable because it dealt with issues of cost allocation and rate design, not base ROE. The Complainants argue that Commission precedent involving cases in which both the zone of reasonableness and ROE were at issue clearly indicate that the zone of reasonableness is not a zone of immunity.[83]

48. The Complainants argue that the NETOs' zone of immunity argument is contrary to the Regulatory Fairness Act.[84] The Complainants also argue that Order No. 679 and Commission precedent on incentive ROE adders do not render any ROE below the top of the zone of reasonableness ipso facto reasonable; rather, the Complainants assert that those cases hold that the Commission is authorized to place the total ROE below the top

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[79] EMCOS Brief Opposing Exceptions at 10-11.

[80] Complainants Brief Opposing Exceptions at 11-13 (citing *FPC v. Natural Gas Pipeline Co.*, 315 U.S. 575 (1942); *FPC v. Conway Corp.*, 426 U.S. 271, 278-279 (1976); *Montana-Dakota*, 341 U.S. 246); EMCOS Brief Opposing Exceptions at 7-8 (citing *FPC v. Conway Corp.*, 426 U.S. at 278-79).

[81] Complainants Brief Opposing Exceptions at 14-18.

[82] Trial Staff Brief Opposing Exceptions at 11 (citing Initial Decision, 144 FERC ¶ 63,012 at n.45).

[83] Complainants Brief Opposing Exceptions at 21 (citing *Golden Spread Elec. Coop. Inc. v. Sw. Pub. Serv. Co.*, Opinion No. 501, 123 FERC ¶ 61,047 (2008), *order on reh'g*, 144 FERC ¶ 61,132 (2013); *Orange & Rockland Utils., Inc.*, Opinion No. 314, 44 FERC ¶ 61,253, at 61,953-55, *modified*, Opinion No. 314-A, 45 FERC ¶ 61,252 (1988), *reh'g denied*, 46 FERC ¶ 61,036 (1989); *Yankee Atomic Elec. Co.*, 40 FERC ¶ 61,372, at 62,212 (1987), *modified*, 43 FERC ¶ 61,232 (1988)).

[84] Complainants Brief Opposing Exceptions at 21-22.

of the zone after applying the adders to a base ROE that represents the Commission's best estimate of a cost-based equity return.[85] Lastly, the Complainants assert that the NETOs' reliance on the Interstate Commerce Act's "Maximum Reasonable Rate" standard is misplaced because it ignores significant differences between the ICA and the FPA, and because the Interstate Commerce Act does not repeal the FPA's just and reasonable standard.[86]

D. Commission Determination

49. We affirm the Presiding Judge's determination on the burden of proof.

50. Under FPA section 206, the burden of proof to show that a rate is unjust and unreasonable "shall be upon the Commission or the complainant."[87] As to what that burden entails in the context of an ROE proceeding, the Supreme Court has held that a just and reasonable ROE should be "commensurate with returns on investments in other enterprises having corresponding risks . . . [and] sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[88] An ROE above that level would exploit consumers and is, therefore, unjust and unreasonable.[89] To estimate the rate of return necessary to attract equity investors, the Commission uses the DCF model, which assumes that a stock's price is equal to the

[85] *Id.* at 24-25 (citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 93; *Promoting Transmission Investment Through Pricing Reform*, 141 FERC ¶ 61,129, at P 11 (2012); *Atl. Grid Operations A LLC, et al.*, 135 FERC ¶ 61,144, at PP 88, 94 (2011)).

[86] Complainants Brief Opposing Exceptions at 26-27.

[87] 16 U.S.C. § 824e(b) (2012).

[88] *Hope*, 320 U.S. at 603; *see also Bluefield*, 262 U.S. at 693 ("The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.").

[89] *Jersey Cent. Power & Light Co. v. FERC*, 810 F.2d 1168, 1180 (D.C. Cir. 1987) (*en banc*) ("In addition to prohibiting rates so low as to be confiscatory, the holding of [*Hope*] makes clear that exploitative rates are illegal as well."); *see also Washington Gas Light Co. v. Baker*, 188 F.2d 11, 15 (D.C. Cir. 1950), *cert. denied*, 340 U.S. 952 (1951).

present value of the infinite stream of expected dividends discounted at a market rate commensurate with the stock's risk.[90]

51. We reject the NETOs' argument that the Commission does not have the authority under FPA section 206 to change the existing base ROE unless the evidence shows that it is entirely outside the zone of reasonableness. As the Presiding Judge correctly noted, the Commission previously rejected this argument in *Bangor Hydro*.[91] We do so here for the same reasons. As the Commission explained in that case, the premise of the NETOs' contention is that every ROE within the "zone of reasonableness" is necessarily "just and reasonable." However, this premise is without substantive merit, because it fails to recognize that the determination of a zone of reasonableness is simply the first step in the determination of a just and reasonable ROE for a utility or group of utilities.

> When the Commission identifies a "zone of reasonableness" in a particular case, it identifies a range that reflects the "substantial spread between what is unreasonable because it is too low and what is unreasonable because it is too high." However, not every rate within this "substantial spread" would necessarily be just and reasonable if charged. Certain rates, though within the zone, may not be just and reasonable given the circumstances of the case.[92]

52. The decision of the United States Court of Appeals for the District of Columbia Circuit in *S. Cal. Edison Co. v. FERC*,[93] supports this conclusion. In that case, the utility filed to modify its rates under FPA section 205. The court stated that section 205 required the Commission to approve the utility's rate proposal "as long as the new rates are just and reasonable."[94] Nevertheless, the court also held that the Commission had

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[90] *See, e.g., S. Cal. Edison Co. v. FERC*, 717 F.3d at 179.

[91] *See Bangor Hydro*, 122 FERC ¶ 61,038 at PP 10-15.

[92] *Id.* P 11 (quoting *Montana-Dakota*, 341 U.S. at 251).

[93] *S. Cal. Edison Co. v. FERC*, 717 F.3d at 181-82 (finding that the Commission had authority to set a utility's ROE at the median of the zone of reasonableness even though the utility proposed using the midpoint, which was also within the zone of reasonableness); *accord Montana-Dakota*, 341 U.S. at 251 (explaining that while statutory reasonableness is an abstract concept represented by an area rather than a pinpoint the Commission must translate that concept into a concrete rate, and it is the rate—not the abstract concept—that governs the rights of the buyer and seller).

[94] *S. Cal. Edison Co. v. FERC*, 717 F.3d at 181.

authority to require the utility's ROE to be set at the median of the zone of reasonableness, even though the midpoint ROE proposed by the utility was also within the zone of reasonableness. In short, the court recognized that the Commission need not treat every ROE within the zone of reasonableness as an equally just and reasonable ROE. If the Commission were required to find any and every ROE within the zone of reasonableness to be equally just and reasonable, the Commission would be required to accept any ROE proposed by a utility in a section 205 rate case, even an ROE at the very top of the zone of reasonableness, as long as that ROE did not exceed the top of the range of reasonableness. However, the FPA has never been understood to require such a result.

53. FPA section 206 contains the same "just and reasonable" standard as FPA section 205. Yet the NETOs effectively contend that we must apply a different just and reasonable standard in section 206 cases than in section 205 cases.[95] Despite the fact FPA section 205 does not require that every ROE within the zone of reasonableness be considered equally just and reasonable for purposes of a utility rate filing under FPA section 205, the NETOs would require us to treat every existing ROE within the zone of reasonableness as equally just and reasonable in a section 206 case. Nothing in the FPA, however, supports such a different understanding of the phrase "just and reasonable" as between those two sections of the FPA when establishing a utility's ROE.

54. We further find to be misplaced the NETOs' reliance on *City of Winnfield*, for the proposition that in a section 206 proceeding a utility's existing rates must "be found to be entirely outside the zone of reasonableness before the agency can dictate their level or form." *City of Winnfield* involved a utility's section 205 proposal to design its rates based on incremental fuel costs rather than average system costs; the case did not involve the ROE component of a utility's cost of service. Thus, the court was not using the phrase "zone of reasonableness" as it is commonly used in proceedings involving a utility's ROE.[96]

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[95] Given that the FPA was intended to be a consumer-protection statute, *see, e.g.*, *Pub. Sys. v. FERC*, 606 F.2d 973, 979 n.27 (D.C. Cir. 1979), it is hard to find persuasive an argument that would allow, under FPA section 205, a utility to propose an increase in its ROE to anywhere in the zone, but would effectively bar, under FPA section 206, a customer from seeking to decrease the ROE being challenged merely because the ROE falls somewhere within the zone.

[96] The Commission's *Texas Eastern* order, also relied on by the NETOs, is distinguishable for the same reason, because it also involved cost allocation and rate design issues, rather than the determination of an entity's ROE.

55. For these reasons, we therefore conclude that the zone of reasonableness produced by a DCF analysis does not create a zone of immunity for a utility's ROE.

V. Appropriate Time Period for the Base ROE in this Proceeding

A. Initial Decision

56. The Presiding Judge found that a separate, higher ROE is appropriate for the "locked in/refund period" from October 2011 through December 2012,[97] and therefore established two separate ROEs: one for the refund period and one to apply prospectively.[98] The Presiding Judge found the just and reasonable base ROE for the refund period to be 10.6 percent, based on the NETOs' DCF data from May 2012 through October 2012, and the just and reasonable base ROE for the prospective period to be 9.7 percent, based on the NETOs' DCF data from October 2012 through March 2013.[99] The Presiding Judge stated that the DCF analysis and data for the period October 2011 through December 2012 "clearly support a higher ROE" than the data for the prospective period. In establishing two base ROEs, using two different data sets and zones of reasonableness, the Presiding Judge reasoned that the "refund period should be representative of what the true ROE was when calculating refunds, otherwise it would allow for a windfall and a return of excessive refunds, based upon supporting data which did not exist at the time."[100]

B. Briefs on Exceptions

57. The Complainants, EMCOS, and Trial Staff argue that the Initial Decision erred in adopting two base ROEs in this proceeding.[101] The Complainants, EMCOS, and Trial

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[97] The refund period is the 15-month period commencing on the refund effective date established in an FPA section 206 proceeding. In this case, the refund period is October 1, 2011 (i.e., the refund effective date) through December 31, 2012.

[98] Initial Decision, 144 FERC ¶ 63,012 at P 585. The Presiding Judge adopted the NETOs' values for both time periods, establishing base ROEs of 10.6 percent for the refund period and 9.7 percent for the prospective period. *Id.*

[99] *See id.* P 585 (citing NETOs June 6, 2013 Initial Brief at 19).

[100] Initial Decision, 144 FERC ¶ 63,012 at P 585.

[101] Complainants Brief on Exceptions at 19; EMCOS Brief on Exceptions at 19; Trial Staff Brief on Exceptions at 77.

Staff contend that the Commission uses the term "locked-in period" to describe two specific situations, neither of which are present in this case: (1) the rate being litigated has been superseded or is no longer in effect,[102] or (2) significant time has elapsed between the closing of the record and when the Commission issues its order.

58. The Complainants argue that FPA section 206(b) makes clear that the just and reasonable rate to be used in calculating refunds and the just and reasonable rate to be observed prospectively are the same,[103] and this is confirmed by the legislative history of the Regulatory Fairness Act through which that refund provision was added to the FPA.[104] The Complainants also argue that the Initial Decision's establishment of two base ROEs is contrary to Commission precedent clearly indicating that the Commission establishes a single zone of reasonableness and a single ROE.[105] The Complainants

[102] Complainants Brief on Exceptions at 21 (citing Opinion No. 501, 123 FERC ¶ 61,047 at P 65, *order on reh'g*, 144 FERC ¶ 61,132); EMCOS Brief on Exceptions at 19-20 (citing Opinion No. 501, 123 FERC ¶ 61,047 at P 65; *Blue Ridge Power Agency v. Appalachian Power Co.*, Opinion No. 363, 55 FERC ¶ 61,509, at 62,785 (1991)); Trial Staff Brief on Exceptions at 80 (citing *S. Cal. Edison Co.*, 139 FERC ¶ 61,042, a P 21 (2012); *S. Cal. Edison Co.*, 137 FERC ¶ 61,016, at P 33 (2011); Opinion No. 501, 123 FERC ¶ 61,047 at P 56; Opinion No. 363, 55 FERC at 62,785).

[103] Complainants Brief on Exceptions at 22-23 (citing *San Diego Gas & Elec. Co. v. Sellers of Ancillary Services Into Markets Operated by the Cal. Indep. Sys. Op. Corp. and Cal. Power Exchange Corp.*, 127 FERC ¶ 61,191, at PP 19-20 (2009)).

[104] Complainants Brief on Exceptions at 23 (citing 134 Cong. Rec. 25,129 (1988) (colloquy of Representatives Gejdenson (D-CT) and Sharp (R-IN)).

[105] Complainants Brief on Exceptions at 27-34 (citing Opinion No. 510, 134 FERC ¶ 61,129, *order on reh'g*, 142 FERC ¶ 61,198; Opinion No. 363, 55 FERC ¶ 61,509, *reh'g granted*, Opinion No. 363-A, 57 FERC ¶ 61,100 (1991), *reh'g granted*, Opinion No. 363-B, 58 FERC ¶ 61,193 (1992); *Golden Spread Elec. Coop., Inc. v. Southwestern Pub. Serv. Co.*, 115 FERC ¶ 63,043, at P 104 (2006), *on exceptions*, Opinion No. 501, 123 FERC ¶ 61,047, at PP 62, 65, n.133; Opinion No. 445, 92 FERC ¶ 61,070; Opinion No. 489, 117 FERC ¶ 61,129; *S. Cal. Edison Co.*, 131 FERC ¶ 61,020, at PP 21, 101, *reh'g denied*, 137 FERC ¶ 61,016, *rev. in part granted in part sub nom. S. Cal. Edison Co. v. FERC*, 717 F.3d 177; *Sw. Pub. Serv. Co.*, 53 FERC ¶ 61,084, at 61,240 (1990), *reh'g denied*, 53 FERC ¶ 61,406 (1990)); Trial Staff Brief on Exceptions at 82 (citing *Golden Spread Elec. Coop., Inc., et al. v. Southwestern Pub. Serv. Co.*, 109 FERC ¶ 61,321, at P 16 (2004); Opinion No. 445, 92 FERC ¶ 61,070).

further assert that the Initial Decision's dual ROE approach would be poor policy because it would add "pointless complexity and gaming to ROE litigation."[106]

59. EMCOS contend that setting a single ROE, even when the DCF data for a refund period differs from the DCF data used to set the ROE, is consistent with the "constantly changing nature of DCF analyses and ROEs."[107] EMCOS further argue that the Initial Decision's rationale for setting two ROEs, i.e., that doing so is necessary to avoid a windfall to ratepayers, ignores the fact that ratepayers only benefit from 15 months of refund protection. Thus, EMCOS assert that the Initial Decision fails to adequately balance the interests of investors and ratepayers.[108]

60. Trial Staff states that a policy of setting two base ROE's in one proceeding would lead to illogical results because a simple shift in the procedural schedule would result in both the initial ROE analysis and the updated ROE analysis being based on data from the refund period. Trial Staff asserts that Commission policy on what constitutes a "locked-in period" should not be based on "a mere happenstance shift of a few months in the procedural schedule of a particular case."[109] Further, Trial Staff argues that *Kern River Transmission Co.*, 126 FERC ¶ 61,034 (2009) (*Kern River*), the one case the NETOs cite in favor of two base ROEs, is distinguishable from this case because *Kern River* involved a full rate case in which the ROE data was from 2008 but the data for the utility's other cost of service elements were based on data from a 2004 test period.[110] Trial Staff asserts that the issue in *Kern River* was the synchronization of data over a five-year period, whereas the instant case involves a four-month difference between the end of the refund period and the end of the six-month data period used for determining the base ROE, and involves no synchronization issues.

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[106] Complainants Brief on Exceptions at 34.

[107] EMCOS Brief on Exceptions at 21 (citing *Bluefield*, 262 U.S. at 693; *Consumer Advocate Div. of the Pub. Serv. Comm'n of West Virginia*, 68 FERC ¶ 61,207, at 61,998 (1994)).

[108] EMCOS Brief on Exceptions at 21-22.

[109] Trial Staff Brief on Exceptions at 79.

[110] Trial Staff Brief on Exceptions at 81 (citing *Kern River Gas Transmission Co.*, 126 FERC ¶ 61,034 (2009) (*Kern River*)).

C. Brief Opposing Exceptions

61. The NETOs argue that the Presiding Judge properly recognized that the base ROE for the refund period should reflect the best record evidence of the cost of equity during that period and the base ROE for the prospective period should be based on the most recent data in the record, and therefore it was appropriate for the Presiding Judge to establish two base ROEs. The NETOs contend that the refund period is a "locked-in period" because the Commission establishes that a rate is "locked-in" when "the rate being litigated has been superseded *or is otherwise no longer in effect*."[111] The NETOs argue that after December 31, 2012 the base ROE for the refund period will no longer be in effect because the base ROE will revert to 11.14 percent[112] until the Commission issues its order on the Initial Decision, at which time the Commission will adjust the base ROE that will apply from the date of the order on the Initial Decision to reflect changes in the 10-year U.S. Treasury bonds.

62. The NETOs also argue that the base ROE for the refund period should reflect the best record evidence of the cost of equity during that period, regardless of whether it is a "locked-in period," and to find otherwise would be contrary to ratemaking principles and precedent.[113] The NETOs argue that the Commission's standard practice in electric ROE cases is to use DCF data from during or before the refund period to establish an ROE for the refund period, and none of the cases cited by the Complainants, EMCOS, or Trial Staff support the proposition that the refund period ROE should be based on DCF data from after the close of the refund period.[114]

63. The NETOs contend that FPA section 206(b) does not preclude establishing separate ROEs for the refund and prospective periods, and that this is demonstrated by the Commission's policy of updating ROEs based on changes in the Treasury bond yields, which regularly produces separate rates for the refund period and the prospective period. Further, the NETOs assert that the legislative history of the Regulatory Fairness

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[111] NETOs Brief Opposing Exceptions at 71 (quoting Opinion No. 501, 123 FERC ¶ 61,047 at P 65) (internal quotations omitted) (emphasis added by NETOs).

[112] However, the NETOs explain that the rate will instead revert to the level determined in Docket No. EL13-33-000 if the pending complaint in that proceeding is not dismissed. NETOs Brief Opposing Exceptions at n.108.

[113] NETOs Brief Opposing Exceptions at 74-76 (citing *Kern River*, 126 FERC ¶ 61,034 at P 57).

[114] NETOs Brief Opposing Exceptions at 77-79.

Act did not change the Commission's regulatory process or rate setting standards, and therefore supports the Commission's standard practice of establishing the ROE based on data from before or during the refund period.[115]

D. Commission Determination

64. We find that it is inappropriate to establish two base ROEs in this proceeding. The Commission's long-standing practice is to establish one base ROE in a proceeding, using one zone of reasonableness.[116] The Commission has only established different ROEs for different time periods in a proceeding based on post-hearing adjustments to reflect post-hearing changes in U.S. Treasury bond yields, but those adjustments must remain within the single zone of reasonableness established in the proceeding. Notably, the Presiding Judge and the NETOs have cited no precedent in which the Commission established two base ROEs, based on two zones of reasonableness, in one proceeding. Our general policy has also been to base the zone of reasonableness on the most recent financial data in the record.[117] Here, the most recent data in the record are the data for a 6-month study period from October 2012 through March 2013.[118] This data is reasonably representative of the refund period, as it includes the last three months of that period.

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[115] NETOs Brief Opposing Exceptions at 80-81.

[116] *See, e.g.*, Opinion No. 510, 134 FERC ¶ 61,129, *order on reh'g*, 142 FERC ¶ 61,198; *Sw. Pub. Serv. Co.*, 53 FERC at 61,240, *reh'g denied*, 53 FERC ¶ 61,406.

[117] *See, e.g.*, Opinion No. 489, 117 FERC ¶ 61,129 at P 28; *Sw. Pub. Serv. Co.*, 53 FERC at 61,240, *reh'g denied*, 53 FERC ¶ 61,406. In *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 21 (2010), the Commission did not permit use of updated financial data not available at the time of the utility's filing, and instead relied solely on the U.S. Treasury bond adjustment to update the utility's ROE. However, as discussed *infra*, section VII, we are changing our practice to no longer apply the U.S. Treasury bond adjustment, and instead will determine ROE based on the most recent financial data in the record, including post-test period data.

[118] We acknowledge that Trial Staff submitted DCF data for the 6-month period ending April 2013; however, Trial Staff only provided data for the companies in their own regional proxy group. Thus, the data for the period October 2012 through March 2013 are the most recent DCF data in the record for all companies in the national proxy group.

65. The NETOs nevertheless argue that it is appropriate to establish two base ROEs in this proceeding based on two different zones of reasonableness because the refund period is a locked-in period. We disagree. The NETOs assert that the rate being litigated "is no longer in effect," positing that their base ROE will revert to 11.14 percent at the end of the refund period or that the Commission may adjust the base ROE upon issuance of the instant order to reflect changes in U.S. Treasury bond yields. These arguments are not persuasive.

66. Section 206(b) of the FPA provides that

> [a]t the conclusion of any proceeding under this section, the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date, in excess of those which would have been paid under the just and reasonable rate . . . which the Commission orders to be thereafter observed and in force.[119]

That the NETOs' need not pay refunds between the end of the fifteen-month refund period and the conclusion of the proceeding is purely a matter of refund liability in the context of a section 206 proceeding, it does not require separate ROEs. In other words, that refunds may only be ordered for fifteen months does not mean that two ROEs are required.

67. The Commission's decision at the end of an FPA section 205 proceeding to update a base ROE to reflect changes in capital market conditions following that proceeding similarly does not dictate that the Commission must set a separate, entirely new ROE to be effective prospectively. When the Commission applies its Treasury bond adjustment to an open-ended rate established in an FPA section 205 proceeding, it applies that adjustment "for the entire period the rates are in effect—both up to the date of the Commission's decision and subsequently."[120] The same approach – adopting a single ROE – is equally appropriate here. Further, we agree with Trial Staff that it would be poor policy to establish two base ROEs in one proceeding based, e.g., solely on a happenstance shift in a proceeding's procedural schedule.

[119] 16 U.S.C. § 824e(b) (2012).

[120] *Pac. Gas & Elec. Co.*, 53 FERC ¶ 61,146, at 61,538 (1990). Further, because we are changing our practice to no longer apply the U.S. Treasury bond adjustment, this aspect of the NETOs' argument is moot.

68. The NETOs rely on *Kern River*[121] to argue that Commission policy requires that, where other aspects of a utility's rates are established based on data for a certain time period, those rates should reflect the utility's capital costs during that same period. Therefore, the NETOs argue, their capital costs for the October 2011 to December 2012 refund period must be based on financial data from that period, because the rates they charged during that period reflected their debt and other costs from 2011 to 2012. *Kern River* does not support establishing separate zones of reasonableness for the refund and prospective periods based on the use of financial data from two separate periods. In fact, in *Kern River*, the Commission established a single zone of reasonableness and ROE applicable to both the refund period and prospective period in that NGA section 4 general cost-of-service rate case. In that case, the Commission had to choose between two proxy groups in the record – one based on data from 2004 and one based on data from 2008 – for purposes of determining the pipeline's ROE for all periods. The Commission found that because all other elements of Kern River's rates in that proceeding were being established based on data from a 2004 test year, Kern River's rates should reflect its capital costs from that same time period. Accordingly, the Commission deemed it appropriate to use the data from 2004, rather than data from four years later in 2008, to determine Kern River's cost of equity for both the refund period and going forward. The Commission explained that it would be "internally inconsistent to use debt and equity costs from different periods."[122]

69. Unlike *Kern River*, this proceeding is not a general rate case establishing multiple cost-of-service elements or a utility's weighted cost of capital; rather, it involves only the NETOs' base ROE. Moreover, we are determining the NETOs' cost of capital using data for the six months ending March 2013, which includes the last three months of the refund period; we are not using data from four years after the refund period as some parties sought to do in *Kern River*. As a result, this case does not raise the same types of concerns regarding internal consistency among cost-of-service elements that the Commission faced in *Kern River*. In sum, *Kern River* does not require or support establishing separate ROEs for the refund and prospective periods in this case.

VI. Application of the Two-Step DCF Methodology in This Case

A. General DCF Methodology Issues

70. As discussed below, we affirm the Presiding Judge's finding that the calculation of dividend yields by the Complainants' witness was incorrect and contrary to Commission

[121] *See Kern River*, 126 FERC ¶ 61,034.

[122] *Id.* P 57.

policy, and we describe below the correct method of calculating the average dividend yield to be used in the two-step DCF methodology. We also affirm the Presiding Judge's findings concerning the appropriate sources of dividend growth data to be used in a DCF analysis.

1. Calculation of Dividend Yields

i. Initial Decision

71. The Presiding Judge concluded that the NETOs' witness correctly calculated the average high and low dividend yield for each member of the proxy group for the six-month period,[123] and then correctly increased these yields by one-half of the high and low growth rates to convert them to adjusted dividend yields.[124] The Presiding Judge explained that the dividend yields the NETOs' witness calculated in his April 26, 2013 testimony represent the latest monthly dividend yields available at the time he prepared his testimony, and should be used for the ROE analysis.[125]

72. The Presiding Judge stated that the NETOs' witness and Trial Staff's witness calculated their dividend yields in accordance with Commission policy,[126] where each company's high and low dividend yields are calculated for each month of the six-month dividend yield period. The Presiding Judge explained that the high and low dividend yields for a given month are equal to the current annualized dividend divided by the lowest stock price on any day in the month and the current annualized dividend divided by the highest stock price on any day in the month, respectively. The Presiding Judge further explained that the respective high and low dividend yields for the six-month dividend yield period is then equal to the average of the six monthly high or low dividend yields.[127] The Presiding Judge found that the Complainants' witness did not use the

[123] Initial Decision, 144 FERC ¶ 63,012 at P 559 (citing Ex. NET-300 at 30).

[124] Initial Decision, 144 FERC ¶ 63,012 at P 559 (citing *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176, at P 119 (2008)).

[125] Initial Decision, 144 FERC ¶ 63,012 at P 560.

[126] *Id.* P 561 (citing *Appalachian Power Co.*, 83 FERC at 62,350).

[127] Initial Decision, 144 FERC ¶ 63,012 at P 561 (citing Ex. S-1 at 40-41; Ex. NET-300 at 30).

Commission's long-standing methodology for calculating the dividend yield,[128] and as a result, those dividend yields and the associated DCF results are fatally defective.

ii. Brief on Exceptions

73. Complainants contend that the difference in how the four witnesses calculated the dividend yields involved the sequence in which daily stock prices were identified and sorted to identify the six past months' high and low averaged share prices. The Complainants state that their witness relied on the monthly dividend yields reported by *AUS Utility Reports*, which calculates those yields based on the daily share price at the middle of each month. The Complainants' witness then used the highest of the dividend yields reported by *AUS Utility Reports* for the six relevant months as the high dividend yield, and the lowest of the six dividend yields as the low dividend yield. Complainants state that the difference between the method used by their witness and the method used by the NETOs and Trial Staff is a minor one that does not materially affect any conclusion. Complainants further state that Dr. Woolridge's method of relying on dividend yields reported by a third-party source has an advantage over the other method in that the yields are available to and widely relied upon by investors.[129]

iii. Briefs Opposing Exceptions

74. NETOs agree with the Presiding Judge's determination that Dr. Avera calculated the dividend yields in accordance with Commission policy.[130] NETOs also agree with the Presiding Judge's rejection of Dr. Woolridge's dividend yield calculations because they contain a serious methodological error.[131] NETOs contend that, while Complainants seek to salvage Dr. Woolridge's dividend yields by asserting that his method is "consistent with practices that the Commission has applied in performing its own dividend yield analyses," the cases Complainants cite are contrary to this argument. NETOs argue that the Complainants' attempt to minimize the error by claiming that the difference between Dr. Avera's and Dr. Woolridge's approaches is "immaterial." NETOs further argue that the Appendix that the Complainants attach to their brief, which

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[128] Initial Decision, 144 FERC ¶ 63,012 at P 562 (citing *Appalachian Power Co.*, 83 FERC at 62,350 (where the Commission cited its policy that dividend yields should be based upon the average high and low dividend yield for the six-month period)).

[129] Complainants Brief on Exceptions at 93.

[130] NETOs Brief Opposing Exceptions at 53-54.

[131] *Id.* at 56.

substitutes Dr. Avera's dividend yield data for Dr. Woolridge's, only addresses the April 17, 2013 proxy group, upon which Dr. Woolridge no longer relies. NETOs further state that the Appendix only shows Dr. Avera's dividend yields for the companies that are common to both proxy groups. They note that the one company missing from the Appendix, Unisource Energy Corp. (Unisource Energy), is the company that forms the high end of Dr. Woolridge's proxy group. Finally, NETOs argue that the dividend yield for Unisource Energy shown in Dr. Woolridge's analysis is incorrect, and thus Dr. Woolridge's April 17, 2013 DCF range and midpoint are wrong.[132]

iv. Commission Determination

75. As discussed in the preceding section, the dividend yield calculations in this case should be based on financial data for the six-month period ending March 2013.[133]

76. While the parties dispute the Presiding Judge's determination regarding the calculation of high and low dividend yields, that issue is mooted by our application of the two-step DCF methodology to public utilities. The two-step DCF methodology does not require the calculation of high and low dividend yields; rather, it requires the calculation of a single dividend yield for each member of the proxy group.[134] However, we do agree with the Presiding Judge that the Complainants improperly based their dividend yield calculations on the monthly dividend yields reported by *AUS Utility Reports*, which apparently calculates those yields based on the daily share price at the middle of each month. Rather than rely on dividend yields published in a newsletter that has not been shown to be widely relied on by investors, we find that it is more accurate to directly calculate dividend yields based on actual stock prices reported by the New York Stock Exchange or NASDAQ, and the company's own indicated dividends. Moreover, we find that our reliance on an average of the high and low stock prices for each month, as described below, produces a dividend yield that is more representative of financial

[132] *Id.* at 56-58 (citing *Consumers Energy Co.*, 98 FERC ¶ 61,333, at 62,416 (2002); *Orange & Rockland Utils., Inc.*, 40 FERC ¶ 63,053, at 65,202 (1987) (calculating the average monthly dividend yield for each month), *on exceptions*, Opinion No. 314, 44 FERC at 61,953, n.17, *order on reh'g*, Opinion No. 314-A, 45 FERC ¶ 61,252; *Conn. Light & Power Co.*, Opinion No. 305-A, 45 FERC ¶ 61,370, at 62,162 (1988) (calculating the average of the high stock prices for each month and the average of the low stock price for each month)).

[133] Initial Decision, 144 FERC ¶ 63,012 at P 559 (citing Ex. NET-300 at 30; Ex. NET-304 at note (a); Ex. NET-702 – UPDATED at note (a)).

[134] *See* Opinion No. 510, 134 FERC ¶ 61,129 at PP 232-234.

conditions during the entire month than is the *AUS Utility Report's* reliance on a single day's stock price from the middle of the month.

77. Accordingly, we find that the dividend yields of the proxy companies in this case should be calculated in the same manner that the Commission has consistently calculated dividend yields when applying the two-step DCF methodology. That methodology derives a single dividend yield for each proxy group company, using a three step process: (1) averaging the high and low stock prices as reported by the New York Stock Exchange or NASDAQ for each of the six months in the study period; (2) dividing the company's indicated annual dividend for each of those months[135] by its average stock price for each month (resulting in a monthly dividend yield for each month of the study period); and (3) averaging those monthly dividend yields.

78. As the Commission found in *Portland*, the method described above for calculating dividend yield for the two-step DCF methodology is an appropriate method of calculating the average dividend yield because "it matches each average monthly stock price with the actual dividend paid for that month to calculate the actual dividend yields for each of the preceding six months."[136] As the Commission also noted in *Portland*, this method is preferable to calculating the estimated dividend yield for each proxy group member based only on the dividend declared in the final month of the period. Using only the dividend declared in the final month results in a mismatch between the stock prices and the dividends used to calculate a firm's dividend yield. This can result in overstated dividend yields, particularly when a firm raises it dividends or distributions during the six-month study period, because earlier stock prices do not reflect the increased value of the stock resulting from the increased dividend or distribution.[137]

2. Acceptable Sources of Analyst Growth Rate Data

i. Initial Decision

79. For the prospective period, the Presiding Judge adopted the NETOs' growth rate estimates from the October 2012 to March 2013 study period,[138] which were based on

[135] In Opinion No. 510, the Commission approved the use of the most recent dividend declared by the relevant company to determine the "indicated annual dividend" for each of the six months.

[136] Opinion No. 510, 134 FERC 61,129 at P 234.

[137] *Id.* P 234.

[138] Initial Decision, 144 FERC ¶ 63,012 at P 565.

five-year IBES growth rates published by *Yahoo! Finance*.[139] The Presiding Judge noted that the Commission has previously relied on IBES growth rate projections published by *Yahoo! Finance* for many years.[140] The Presiding Judge also adopted the NETOs' position that, in order for an IBES growth projection to be used, *Yahoo! Finance* must indicate that at least two analysts cover the electric utility in question.[141] The Presiding Judge rejected Trial Staff's proposal to use growth projections from the Reuters Estimates Database (RED) when necessary, to assure that the growth projection is based on the estimate of more than one analyst.

80. Consistent with the Presiding Judge's holdings on the appropriate sources of analyst growth projections, the Presiding Judge adopted the NETOs' proposed 8.07 percent IBES growth projection in *Yahoo! Finance* for UIL Holdings. The Presiding Judge rejected Trial Staff's proposed 6.03 percent growth projection for UIL Holdings based on the average of two analyst growth projections in RED, one of 4.0 percent and one of 8.07 percent. The Presiding Judge agreed with the NETOs that it was more likely than not that the 4.0 percent growth projection in RED was a stale projection from one year ago, because RED indicated that the mean growth projection from one year before was 4.0 percent. The Presiding Judge further found that, whether only one or two analysts projected 8.07 percent growth for UIL Holdings, the fact that growth projection was reported in both IBES and RED was sufficient to confirm its use in this proceeding.[142]

ii. Briefs on Exceptions

81. Trial Staff takes issue with exclusive reliance on IBES analyst growth rate estimates published by *Yahoo! Finance*, arguing that the estimates are unreliable and stale.[143] Trial Staff states that *Yahoo! Finance* does not provide information regarding the number of analysts contributing to the IBES growth projection or the date of the growth projections. However, Trial Staff states, Thomson Reuters on Demand, which publishes the same IBES growth projections as *Yahoo! Finance*, also provides both the number of analysts contributing to each IBES growth projection and the age of those

[139] *Id.* P 552.

[140] *Id.* P 566.

[141] *Id.* P 544.

[142] *Id.* P 596 n.85.

[143] Trial Staff Brief on Exceptions at 62-66.

projections. Trial Staff argues that the use of a single analyst growth rate projection is inconsistent with the Commission's preference for consensus, two-analyst estimates.[144] Therefore, Trial Staff contends that, when Thomson Reuters on Demand indicates that the IBES growth rate reflects the view of only one analyst, the RED mean analyst growth rate should be used instead. Trial Staff states that RED is published on Thomson Reuter's website *reuters.com*, which is a free public website with different employees from Thomson Reuters on Demand. That website provides (1) RED analyst growth estimates, (2) the number of analysts contributing to the mean estimate, (3) the high and low estimate, and (4) the mean estimate one year ago.

82. Trial Staff argues that the Initial Decision contains no citations to support the Presiding Judge's finding that Commission policy mandates use of IBES data to the exclusion of any other source. Further, Trial Staff states that in Opinion No. 489 the Commission noted that the presiding judge in that case was not precluded "from finding candidates for inclusion in the proxy group for which comparable data can be reasonably substituted for the growth rate data reported by IBES."[145] Trial Staff argues that the Commission has not specifically addressed the quality of the growth rate estimates as sourced from the *Yahoo! Finance* website and for this reason the Commission has never previously determined whether another source should also be used when IBES data turns out to be stale or not based on consensus estimates.[146]

83. Complainants similarly contend that although the Commission has previously referenced IBES forecasts obtained from *Yahoo! Finance*, it has made clear that this approval is not exclusive of other credible sources.[147] Complainants contend that Trial Staff's approach of turning to Reuters when IBES reports only one analyst's long-term growth estimate is a better way to handle the unprecedented circumstance of a single analyst's forecast which threatens to drive the high or low cost of equity estimate.[148]

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[144] *Id.* at 67-69.

[145] *Id.* at 64-65 (citing Opinion No. 489, 117 FERC ¶ 61,129 at P 8, *order on reh'g*, 122 FERC ¶ 61,265, *order granting clarification*, 124 FERC ¶ 61,136 (2008)).

[146] Trial Staff Brief on Exceptions at 66 (citing *Proxy Group Policy Statement*, 123 FERC ¶ 61,048 at PP 83-84 (conditionally allowing, but not requiring, reference to growth forecasts published by Yahoo), *reh'g denied*, 123 FERC ¶ 61,259 (2008)).

[147] Complainants Brief on Exceptions at 71.

[148] *Id.* at 72-73.

84. Trial Staff, Complainants, and the EMCOS also oppose the Presiding Judge's acceptance of the NETOs' proposal to use the IBES 8.07 percent growth rate for UIL Holdings. Trial Staff states that the use of a single analyst's growth rate projection for UIL Holdings is inconsistent with the NETOs' assertion that a public utility must be covered by two analysts to be included in the proxy group.[149] Trial Staff also disagrees with the Presiding Judge's conclusion that RED data supports the latest IBES growth projection for UIL Holdings of 8.07 percent. Trial Staff states that the RED data indicates a proper consensus growth estimate of 6.03 percent, based on two analysts' estimates, one of 8.07 percent and one of 4.0 percent. Trial Staff also disputes the Presiding Judge's conclusion that the 4.0 percent growth rate estimate is stale.[150] While the RED data shows that the estimate for one year ago was 4.0 percent, it does not state that the current 4.0 estimate is the same year-old estimate. Moreover, Trial Staff argues that the time periods for the growth rate estimates and the dividend yields were not synchronized, and that this could lead to distorted results.[151]

85. Complainants and EMCOS argue that the Presiding Judge's reliance on the UIL Holdings IBES growth rate from *Yahoo! Finance* was in error since it was based on a single analyst's estimate, the estimate was attributed too much weight, the application of the estimate was asynchronous with the dividend yields period, and an adjustment should have been made to avoid double-counting transmission incentives.[152] EMCOS further argues that the Presiding Judge erred in not using growth rate sources that it put forth for UIL Holdings, including Zacks and DailyFinance.com.[153]

iii. Briefs Opposing Exceptions

86. The NETOs argue that the Presiding Judge was correct to accept their use of IBES growth rate estimates from *Yahoo! Finance*, because the Commission has routinely relied on *Yahoo! Finance* as a source of IBES growth rate data.[154] The NETOs state that the

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[149] Trial Staff Brief on Exceptions at 67-70.

[150] *Id.* at 70-72.

[151] *Id.* at 73-74.

[152] Complainants Brief on Exceptions at 67-78; EMCOS Brief on Exceptions at 25-27.

[153] EMCOS Brief on Exceptions at 24.

[154] NETOs Brief Opposing Exceptions at 34.

Presiding Judge was correct to adopt the NETOs' proxy group screening criteria requiring that all proxy group members be "[e]lectric utilities that are covered by at least two industry analysts."[155] However, the NETOs state, this requirement does not mean that the IBES growth projection must be based on growth projections of more than one analyst. The NETOs explain that *Yahoo! Finance* indicates how many analysts cover a particular electric utility, but it does not identify the number of analysts contributing to its growth rate estimates.[156] Nevertheless, the Commission has consistently relied on IBES growth projections in *Yahoo! Finance* and has never required that IBES growth rates used in the DCF calculation be based on estimates provided by two analysts, and the Commission did not require it in *Atlantic Path15* or *Southern California Edison* or any other case.

87. NETOs also take issue with Trial Staff's reliance on data from RED, noting that the Commission will rely on such data only when IBES data is not available.[157] NETOs support the Presiding Judge's use of the most recent growth rate data even though it was submitted after the deadline for submitting final DCF results, because the Presiding Judge allowed parties to submit additional testimony on the issue.[158] NETOs argue that the more recent data on UIL Holdings indicates that the investment community changed its view of UIL Holdings's growth prospects.[159] NETOs disagree with Trial Staff that there was an inconsistency between the UIL Holdings growth rate and dividend data used in the DCF analysis; that the Presiding Judge used the wrong updated data; that two sources of long-term growth data are required for a company to remain in the proxy group; and that the Commission should reject the use of *Yahoo! Finance* growth estimates in this proceeding.[160] Finally, NETOs argue that the Commission should affirm the Presiding Judge's rejection of the Complainants' incentive adjustment to UIL Holdings's growth rate.[161]

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[155] *Id.* at 16 (emphasis removed).

[156] *Id.* at 16-19.

[157] *Id.* at 35-36 (citing *Proxy Group Policy Statement*, 123 FERC ¶ 61,048 at P 84).

[158] NETOs Brief Opposing Exceptions at 38-39.

[159] *Id.* at 40.

[160] *Id.* at 41-44.

[161] *Id.* at 50.

iv. Commission Determination

88. We affirm the Presiding Judge's adoption of the NETOs' five-year IBES growth rate data contained in its witness's April 26, 2013 testimony. The growth rate used in the DCF model should be the growth rate expected by the market. That growth rate may not necessarily prove to be the correct growth forecast, but the cost of common equity to a regulated enterprise depends upon what the market expects, not upon what ultimately happens. Accordingly, it is appropriate to look to the most recent record evidence of the growth rates actually expected by the investment community.[162]

89. The Commission has long relied on IBES growth projections as evidence of the growth rates expected by the investment community.[163] Since the discontinuation of the IBES Monthly Summary Data Book in 2008, the Commission has consistently used IBES growth rate estimates published by *Yahoo! Finance* as the source of analysts' consensus growth rates.[164] The NETOs have provided the requisite IBES growth rate figures published by *Yahoo! Finance* for every company in the national proxy group we adopt later in this order.[165]

90. We reject Trial Staff's proposal to use RED growth projections published by *reuters.com* for some of the proxy companies in place of the *Yahoo! Finance* IBES growth projections. Although the Commission has previously stated that "comparable data can be reasonably substituted for the growth rate data reported by [IBES] or Value

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[162] *See Kern River*, 126 FERC ¶ 61,034 at P 120; *Proxy Group Policy Statement*, 123 FERC ¶ 61,048 at P 73; *Transcon. Gas Pipe Line Corp.*, 85 FERC at 61,268-69.

[163] *See, e.g.*, *RITELine Ill., LLC*, 137 FERC ¶ 61,039, at P 68 (2011); *N. Pass Transmission LLC*, 134 FERC ¶ 61,095, at P 46 (2011); *Pub. Serv. Elec. & Gas Co.*, 126 FERC ¶ 61,219, at P 62 (2009); Opinion No. 445, 92 FERC at 61,257.

[164] *See, e.g.*, *N. Pass Transmission LLC*, 134 FERC ¶ 61,095 at P 52 (approving proxy selection criteria that required available IBES and Value Line data); *RITELine Ill., LLC*, 137 FERC ¶ 61,039 at P 71; *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281, at P 92 (2009); *Pub. Serv. Elec. & Gas Co.*, 126 FERC ¶ 61,219 at P 62 (approving a screen which excluded companies for which no IBES or Value Line data is available).

[165] The workpapers provided by the NETOs' witness do not include an IBES growth projection for CH Energy Group, and therefore that company will not be included in the proxy group. *See* Ex. NET-702 – UPDATED; NETOs, "Workpapers for the Respondents' Supplemental Testimony of Dr. William Avera under EL11-66" (dated Apr. 19, 2013).

Line" when the IBES growth rate figures are not available,[166] that is not the case here, because the NETOs have provided IBES growth data for all relevant companies. The Presiding Judge correctly found that the Commission has never required that there be two (or more) analysts' long-term growth rates for a company in order for it to be included in a proxy group. Trial Staff has only provided RED growth estimates for the few companies for which it asserts the IBES growth projection only reflects the view of one analyst. As a result, it is not possible to use RED growth estimates for all the companies in the proxy group. We find that an alternate source of growth rate data should only be used when that source can be used for the growth projections of all of the proxy group companies. Using different sources of growth rate data for different companies in a proxy group could produce skewed results, because those sources may take different approaches to calculating growth rates. Moreover, while the sources of growth rate data often rely on many of the same analysts in publishing their estimates, the different sources may use slightly different time periods from one another. For this reason, the Commission has consistently used a single investor service such as IBES for the investment analysts' growth rate estimate.[167] Therefore, while we reaffirm that there may be more than one valid source of growth rate estimates, in order to ensure that growth rate estimates are internally consistent in an ROE analysis we find it inappropriate to use estimates from different sources for different proxy group companies.

91. Consistent with the above discussion, we also find that the Presiding Judge correctly adopted the NETOs' proposed 8.07 percent IBES growth projection in *Yahoo! Finance* for UIL Holdings. While Thomson Reuters on Demand indicates that the UIL Holdings IBES growth rate reflects the view of only one analyst, we are not persuaded that investors would place less weight upon that IBES growth rate than the other IBES growth projections in *Yahoo! Finance*, which Trial Staff recognizes is a popular website for investors.[168]

B. Composition of the Proxy Group

92. In this section we address the following issues concerning the proper methodology for developing a proxy group and calculating the zone of reasonableness: (1) the use of a national group of companies considered electric utilities by Value Line; (2) the inclusion

[166] *See, e.g., ISO New England, Inc.*, 109 FERC ¶ 61,147, at P 205 (2004); *ISO New England, Inc.*, 110 FERC ¶ 61,111, at P 23 (2005).

[167] *See, e.g., RITELine Ill., LLC*, 137 FERC ¶ 61,039 at P 68; *N. Pass Transmission LLC*, 134 FERC ¶ 61,095 at P 46; *S. Cal. Edison Co.*, 92 FERC at 61,263.

[168] Trail Staff Brief on Exceptions at 62.

of companies with credit ratings no more than one notch above or below the utility or utilities whose rate is at issue; (3) the inclusion of companies that pay dividends and have neither made nor announced a dividend cut during the six-month study period; (4) the inclusion of companies with no major merger activity during the six-month study period; and (5) companies whose DCF results pass threshold tests of economic logic.

1. National Proxy Group vs. Regional Proxy Group

i. Initial Decision

93. The Presiding Judge found it appropriate to use a national proxy group, rather than a regional proxy group, explaining that "the current financial and market conditions are better served by use of a more diverse national proxy group."[169] The Presiding Judge adopted the national proxy group produced by the NETOs' DCF analysis. The Presiding Judge noted that, although Opinion No. 489 happened to involve use of a regional proxy group, the Commission did not expressly prohibit use of a national proxy group, and that the Commission has found national proxy groups preferable.[170] However, the Presiding Judge agreed with the NETOs that, because several of the NETOs either do not have credit ratings or have Moody's credit ratings two notches lower than their S&P credit ratings, a national proxy group is more reflective of the NETOs than is a regional proxy group.[171] The Presiding Judge found that the NETOs' proxy group substantially complies with Commission precedent,[172] but that Trial Staff's proxy group was deficient because it relied primarily on companies that are significantly larger than most of the NETOs.[173]

ii. Briefs on Exceptions

94. EMCOS argues that using a large national proxy group could include outliers that will skew the ROE analysis, and that this concern is even more pressing when using the

[169] Initial Decision, 144 FERC ¶ 63,012 at P 551 n.49.

[170] *Id.*

[171] *Id.*

[172] *Id.* P 553 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at PP 32, 51 (using same proxy group criteria as Dr. Avera, but also requiring minimum revenues of $1 billion, which is inapplicable here given the NETOs' sizes).

[173] Initial Decision, 142 FERC ¶ 63,007 at P 554.

midpoint as the measure of central tendency.[174] Trial Staff argues that the Commission has never applied a national proxy group to estimate the base ROE for a diverse group of utilities[175] and Commission policy favors the use of a regional proxy group.[176] Trial Staff argues that its regional proxy group is the best reflection of the appropriate quality, span, and distribution of the NETOs' diverse risks.[177] Trial Staff further argues that pivotal issues in the Initial Decision include recognition of both S&P and Moody's credit ratings, and Ms. Lapson's presumption that unrated entities should be presumed to have near-junk or junk ratings of BBB- and lower.[178] Trial Staff explains that the Commission has found that it is appropriate to use a corporate credit rating screen of all investment grade companies when an applicant has no credit rating of its own.[179] Trial Staff argues that the Presiding Judge and the NETOs both failed to establish any relationship between the Morningstar market capitalization theory and the *Hope* and *Bluefield* goals, nor did they establish how "size" should be weighed against credit ratings in evaluating risk in this case. Trial Staff contends that the record does not support "size" as a superior criterion to credit ratings for determining a company's business and financial risk, and argues that credit ratings are the superior measure for developing comparable risk proxy groups.[180]

iii. Briefs Opposing Exceptions

95. The NETOs argue that the Presiding Judge correctly ruled that Commission precedent favors the use of a national proxy group, and that their national proxy group is more representative of the NETOs than Trial Staff's regional group.[181] NETOs contend that Trial Staff's regional proxy group selection is inappropriate because: (1) it cannot

[174] EMCOS Brief on Exceptions at 29-30 (citing *S. Cal. Edison Co.,* 137 FERC ¶ 61,016 at P 21, *aff'd sub nom. S. Cal. Edison Co. v. FERC,* 717 F.3d 177).

[175] Trial Staff Brief on Exceptions at 18.

[176] *Id.* at 18-19.

[177] *Id.* at 44.

[178] *Id.* at 40.

[179] *Id.* at 37-41 (citing *Atl. Grid Operations A LLC,* 135 FERC ¶ 61,144 at P 88 n.55).

[180] Trial Staff Brief on Exceptions at 30-31.

[181] NETOs Brief Opposing Exceptions at 6-7, 22-23.

fairly be called a regional proxy group for New England; (2) the Commission has never rejected a DCF study using a national proxy group; (3) there is no economic basis for comparable risk to be tied to the measure of central tendency; (4) the NETOs must compete for equity capital with utilities world-wide; and (5) it is not representative of the NETOs' business and financial risks.[182]

iv. Commission Determination

96. We find that it is appropriate to use a national proxy group, and we therefore affirm the Initial Decision's adoption of the NETOs' national proxy group.[183] Whether it is more appropriate to use a national proxy group or a regional proxy group is a question of capital attraction and comparability of risk.[184] We agree that "the NETOs must compete for capital with other utilities (and companies in other sectors) throughout the nation,"[185] and that investors are not limited to investments in geographically adjacent states but instead participate in national or international capital markets.[186] If the NETOs' ROE is significantly less than the returns of utilities in other parts of the nation, capital will more readily flow to areas other than New England and the NETOs may not be able to attract sufficient capital consistent with the *Hope* and *Bluefield* standards. Further, widening the geographic range of the proxy group allows for the application of more stringent screening criteria, to refine the proxy group to a level of risk more comparable, while maintaining a group of proxy companies that is sufficiently large and diverse to reliably capture the range of reasonable returns.[187] Moreover, in determining

[182] *Id.* at 7-11.

[183] *See* Initial Decision, 144 FERC ¶ 63,012 at P 541 n.49.

[184] *See generally Proxy Group Policy Statement*, 123 FERC ¶ 61,048 at P 48 ("[T]he purpose of the proxy group is to 'provide market-determined stock and dividend figures from public companies comparable to a target company for which those figures are unavailable.['] . . . It is thus crucial that the firms in the proxy group be comparable to the regulated firm whose rate is being determined. In other words, as the court emphasized in *Petal*, the proxy group must be 'risk-appropriate.'") (quoting *Petal Gas Storage, L.L.C. v. F.E.R.C.*, 496 F.3d 695, 699 (D.C. Cir. 2007) (*Petal Gas*)).

[185] *Proxy Group Policy Statement*, 123 FERC ¶ 61,048 at P 434.

[186] *Id.* P 443.

[187] *See* Initial Decision, 144 FERC ¶ 63,012 at P 71.

comparability of financial and business risks, financial data is much more probative than geographical proximity.[188]

2. Value Line Electric Utilities

i. Initial Decision

97. The Presiding Judge found that the NETOs' use of *Value Line*'s electric utilities list as a proxy screen is consistent with Commission policy.[189] The Presiding Judge found that the Complainants' proposed proxy group is deficient, because they required that each proxy group company be followed by multiple financial services companies, which the Commission has never required.[190]

ii. Briefs on Exceptions

98. Complainants argue that the Presiding Judge should have accepted their use of *AUS Utility Reports* instead of *Value Line* as a proxy group screen, as well as their elimination of proxy companies that do not derive at least 50 percent of their revenues from regulated electric operations[191]

iii. Briefs Opposing Exceptions

99. The NETOs state that the Presiding Judge properly rejected the Complainants' requirements that the proxy group members be included in *AUS Utility Reports* and derive 50 percent of their revenues from regulated electric utility operations. The NETOs argue that their proxy group criteria already screen out companies that investors do not consider to be electric utilities by excluding companies not included in *Value Line*'s electric utility industry group. The NETOs further argue that Dr. Woolridge's 50 percent

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[188] *See S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 29 ("We are persuaded by the parties that using a national proxy group in this case complies with the *Hope* standard of risk that is necessary 'to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.'") (quoting *Hope*, 320 U.S. at 603).

[189] Initial Decision, 144 FERC ¶ 63,012 at P 552 (citing *Atl. Path 15, LLC*, 122 FERC ¶ 61,135 at P 20, *order on reh'g*, 133 FERC ¶ 61,153 (2010); *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at PP 32, 51).

[190] Initial Decision, 144 FERC ¶ 63,012 at P 554.

[191] Complainants Brief on Exceptions at 90-91.

electric revenue test does not follow the Commission's decision in Docket No. ER04-157. Specifically, the NETOs contend that UGI Corporation (UGI) was excluded in that case because its regulated electric utility revenues were less than 5 percent of its total revenues and it was not classified as an electric utility by *Value Line*. The NETOs claim that the Commission did not establish a bright line revenues test in that case, nor has it ever done so.[192]

iv. Commission Determination

100. We affirm the Initial Decision's use of *Value Line* data as a proxy group screen. The Commission has previously relied on *Value Line*'s electric utility group listing to determine whether a company's risks warrant its exclusion from the electric proxy group.[193] We reject the Complainants' use of *AUS Utility Reports* instead of Value Line. The Commission has never relied upon *AUS Utility Reports* and we are not persuaded that it is appropriate to do so now. Unlike *Value Line*, which is an investment-oriented publication, *AUS Utility Reports* is a service published primarily for regulators and is not typically relied upon by investors.[194]

101. We also reject the Complainants' requirement that a company derive at least 50 percent of its revenues from regulated electric utility operations. The Commission has never applied a percentage threshold related to revenue sources, as determined by *AUS Utility Reports* or any other outlet, beyond which a utility is no longer considered an electric utility. While the Complainants correctly state that the Commission in Docket No. ER04-157 excluded UGI because it "receive[d] less than 5 percent of its revenue from its regulated electric utility operations," and was primarily a gas company rather than an electric company,[195] the Commission did not establish a percentage threshold for revenue sources. The Commission instead focused on the fact that UGI's risk profile was

[192] NETOs Brief Opposing Exceptions at 19-21 (citing *Bangor Hydro-Elec. Co.*, 111 FERC ¶ 63,048, at PP 29, 58, 61 (2005), *order on initial decision*, Opinion No. 489, 117 FERC ¶ 61,129 at PP 34, 37-38, *order on reh'g*, 122 FERC ¶ 61,265, *order granting clarification*, 124 FERC ¶ 61,136 (2008)).

[193] *See Atl. Grid Operations A LLC*, 135 FERC ¶ 61,144 at P 96; *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 51.

[194] Ex. NET-300 at 116.

[195] Complainants Brief on Exceptions at 91.

"significantly different than the risk profile of an electric utility company and the other companies in the proxy group."[196]

102. We therefore find that the appropriate starting point for the two-step DCF methodology will be the 49 companies, from across the United States, that *Value Line* classifies as being in the electric utility industry.[197] We accept the *Value Line* industry classifications because *Value Line* is a widely-followed, independent investor service; as there may be other reliable sources that investors rely upon, we will not mandate the use of *Value Line* in all cases, and will consider the use of other sources shown to be reliable and commonly relied upon by investors.

3. Credit Ratings

i. Initial Decision

103. The Presiding Judge found that it was appropriate for the NETOs to screen their proxy group to exclude public utilities with corporate credit ratings more than one notch above and below the subject utilities to be appropriate for use in this case, because the Commission has used this as screening criterion in previous cases.[198] The Presiding Judge also found that Trial Staff disregarded this proxy group screen.[199]

ii. Briefs on Exceptions

104. Trial Staff states that it assessed the risk comparability of its regional proxy group using methods consistent with Commission precedent, and the NETOs' adherence to the one-notch risk band convention produces an inferior proxy group for the diverse companies that make up the NETOs.[200] Trial Staff contends that the Commission has

[196] Opinion No. 489, 117 FERC ¶ 61,129 at P 37, *order on reh'g*, 122 FERC ¶ 61,265, *order granting clarification*, 124 FERC ¶ 61,136 (2008).

[197] *See* NETOs, "Workpapers for the Respondents' Supplemental Testimony of Dr. William Avera under EL11-66" (dated Apr. 19, 2013).

[198] Initial Decision, 144 FERC ¶ 63,012 at P 552, n.51 (citing *RITELine Ill., LLC*, 137 FERC ¶ 61,039 at P 68 (using corporate credit ratings one notch above and below target); *N. Pass Transmission, LLC*, 134 FERC ¶ 61,095 at P 46; *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 51).

[199] Initial Decision, 144 FERC ¶ 63,012 at P 553.

[200] Trial Staff Brief on Exceptions at 34.

only applied the one-notch credit rating screen in establishing a base ROE for a single utility and that it should not be used with a diverse group of utilities because it would result in a five-notch band.[201] Trial Staff argues that the unique circumstances of a diverse group of utilities supports dollar-weighted credit rating analyses, and that the NETOs' proxy group is inappropriately skewed toward higher risk.[202] Further, Trial Staff contends that the NETOs' recognition of both S&P and Moody's credit ratings, and the NETOs' presumption that unrated entities should be presumed to have near-junk or junk ratings, are unprecedented and unsupported.[203] Complainants argue that the Presiding Judge erred in rejecting the Complainants' proxy group because it purportedly used screening criteria "foreign to the FERC jurisdiction."[204]

iii. Briefs Opposing Exceptions

105. The NETOs argue that Trial Staff's claim that the NETOs are "dominantly rated A-/BBB+" is based on a flawed assessment of the NETOs' credit ratings. The NETOs assert that a proper analysis shows that they have an average rating of approximately BBB. The NETOs contend that Trial Staff ignored the presence of unrated entities among the NETOs and failed to consider the fact that the Moody's credit ratings of three of the seven NETOs have an S&P rating two notches lower than their S&P ratings. The NETOs also assert that eight of the 12 NETOs are lower rated than Trial Staff assumes. The NETOs contend that investors rely on both S&P and Moody's ratings and would assign either the lower of the two ratings or the average of the two ratings.[205] The NETOs argue that the Commission does not adopt a specific credit rating for unrated entities, but instead defaults to a comparable risk band of all investment grade utilities.[206]

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[201] *Id.* at 35-36.

[202] *Id.* at 37-39.

[203] *Id.* at 40-44.

[204] Complainants Brief on Exceptions at 88.

[205] NETOs Brief Opposing Exceptions at 23-24.

[206] *Id.* at 26-29 (citing *Atl. Grid Operations A LLC*, 135 FERC ¶ 61,144 at P 88 n.55).

iv. Commission Determination

106. We affirm the Initial Decision's finding that it is appropriate to exclude from the proxy group those utilities with corporate credit ratings more than one notch above or below the NETOs' credit ratings. We reject Trial Staff's argument that the precedent on the credit rating band screen is limited to cases involving single utilities and that the screen should not apply in a case involving multiple utilities. The purpose of the credit rating band screen is to include in the proxy group only those companies whose credit ratings approximate those of the utilities whose rate is at issue. For a diverse group of utilities with a range of credit ratings, that approximation may require a credit rating band spanning more notches than the three that are typical in single utility cases. Further, contrary to Trial Staff's assertion, the Commission has in the past permitted comparable risk bands as wide as five credit notches.[207]

107. We further find that ratings from both major credit ratings services should be considered when developing the comparable risk band. As the NETOs correctly state, investors rely upon credit ratings from both S&P and Moody's. Therefore, while the Presiding Judge's application of the credit rating screen using only S&P ratings is consistent with Commission precedent, basing the credit rating screen on data only from S&P does not necessarily provide an accurate estimate of the NETOs' risk. Thus, we find that, in applying the credit rating proxy group screen to exclude companies more than one notch above or below the NETOs' credit ratings, it is appropriate to use both the S&P corporate credit ratings and the Moody's issuer ratings *when both are available*.[208] If a company is more than one notch above or below the credit ratings of the utilities whose rates are at issue based on *either* the S&P ratings *or* the Moody's ratings, that company shall be excluded from the proxy group.

108. Based upon the NETOs' range of S&P credit ratings from A- to BBB, we affirm the Presiding Judge's finding that the appropriate S&P corporate credit rating band screen in this case spans the five notches from A to BBB-. Based upon the record data that the Moody's credit ratings for the NETOs range from A2 to Baa2, we find that the appropriate Moody's credit rating band screen spans the six notches from A1 to Baa3.[209]

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[207] *See, e.g.*, *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248, at 62,240 n.79 (2008) ("For both projects, the Commission screened the proxy group for companies with corporate credit ratings of BBB- to A.").

[208] We will not require that a company have both S&P and Moody's ratings to be eligible for inclusion in a proxy group, and we will screen only on the available rating.

[209] We note that the credit rating bands are based on only those NETOs that have credit ratings from S&P or Moody's.

Four of the initial proxy group companies fall outside one or both of these credit rating bands and are, therefore, excluded from the proxy group. Specifically, we exclude MGE Energy because of its AA- S&P rating; NV Energy, Inc. and PNM Resources, Inc. because of their Ba1 Moody's ratings; and Unisource Energy because of its BB+ S&P rating and its Ba1 Moody's rating.

4. Dividend Payments and Cuts

i. Initial Decision

109. The Presiding Judge found that the NETOs appropriately screened from their proxy group any company that has not paid six months of dividends without a dividend cut.[210] The Presiding Judge also found that Trial Staff's and Complainants' proxy groups were deficient because they required that each proxy group member have paid dividends for three years without any cuts.[211]

ii. Briefs on Exceptions

110. Trial Staff states that the significance of the dividend yield screen is highlighted by the Commission's past practice and finance theory on the limitations of the DCF model. Trial Staff explains that its three-year dividend yield criterion is a non-issue because it did not distort the proxy group results or estimated ROE.[212] Complainants argue that the NETOs failed to consistently follow their own dividend yield criterion and kept Exelon Corp. (Exelon) in the proxy group with adjusted dividend yields of 6-7 percent, despite its announcement in February 2013 that it was cutting its dividend effective April 2013.[213]

iii. Briefs Opposing Exceptions

111. NETOs state that the Presiding Judge properly required each proxy group member to have paid six months of dividends and rejected Trial Staff's and Complainants' proposed requirement that each proxy group member have paid steady or rising dividends

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[210] Initial Decision, 144 FERC ¶ 63,012 at P 552.

[211] *Id.* PP 553-554 (citing Opinion No. 501, 123 FERC ¶ 61,047, *order on reh'g*, 144 FERC ¶ 61,132).

[212] Trial Staff Brief on Exceptions at 44-47.

[213] Complainants Brief on Exceptions at 93 (citing Ex. S-5 at 2-3; Ex. S-7 at 48).

for three years.[214] NETOs state that a three-year dividend yield screen would ignore the fact that the DCF model is based on investors' expected return from the current dividend yield and growth, not historical dividend payments. NETOs argue that Complainants' assertion that the Commission excluded Williams Companies in two cases does not support the exclusion of Empire District here, because the Commission excluded Williams Companies due to its particular financial circumstances, not a dividend cut in the DCF analysis period. NETOs further contend Empire District temporarily suspended its dividend due to a one-time, extreme weather event, not because of financial distress.[215]

iv. Commission Determination

112. We affirm the Initial Decision's finding that it is appropriate to include a utility in the proxy group if it has paid six months of dividends and has not made or announced a dividend cut.[216] We agree with the NETOs that a three-year dividend yield screen would be inappropriate because the DCF model is based on investors' required return from current, not historical, estimates of dividend yield and growth. Accordingly, because Empire District's dividend cut took place outside the six-month study period in this proceeding, we find that it was appropriate for the Presiding Judge to include Empire District in the proxy group. However, Exelon announced during the six-month study period that it would be cutting its dividend in April 2013, and we will therefore exclude Exelon from the proxy group.

5. Merger and Acquisition Activity

i. Initial Decision

113. The Presiding Judge found that the NETOs correctly screened their proxy group to exclude companies with ongoing merger and acquisition (M&A) activity. The Presiding

[214] NETOs Brief Opposing Exceptions at 13 (citing Opinion No. 510, 134 FERC ¶ 61,129, *order on reh'g*, 142 FERC ¶ 61,198).

[215] NETOs Brief Opposing Exceptions at 14-16 (citing *Kern River*, 129 FERC ¶ 61,240; *High Island Offshore System, L.L.C.*, 110 FERC ¶ 61,043 (2005), *vacated and remanded on other grounds sub nom. Petal Gas*, 496 F.3d 695.

[216] *See* Opinion No. 510, 134 FERC ¶ 61,129, *order on reh'g*, 142 FERC ¶ 61,198.

Judge noted that this screen has been used by the Commission in previous cases, and is appropriate for use in this case.[217]

ii. Commission Determination

114. We affirm the Initial Decision's acceptance of the NETOs' M&A screen, as it is consistent with Commission precedent.[218] Our practice is to eliminate from the proxy group any company engaged in M&A activity significant enough to distort the DCF inputs.[219] In applying that screen to the two-step DCF methodology, we affirm the Presiding Judge's elimination of Entergy Corp. and ITC Holdings Corp. from the proxy group due to their ongoing merger activity with each other during the study period, and we eliminate CH Energy Group[220] due to its acquisition by Fortis.[221] While Northeast Utilities was involved in M&A activity in the recent past, the record does not indicate that the M&A activity was significant enough to distort the DCF inputs. Thus, we find that the Presiding Judge appropriately included Northeast Utilities in the proxy group, as it completed its merger with NSTAR on April 12, 2012. Similarly, we agree that it is unnecessary to eliminate Ameren Corp., which announced on March 14, 2013 the sale of its generation business to Dynegy, and CenterPoint Energy and OGE Energy Corp., which also announced on March 14, 2013 the formation of a large master limited partnership for their midstream businesses. No party presented evidence indicating that

[217] Initial Decision, 144 FERC ¶ 63,012 at P 552 (citing *RITELine Ill., LLC,* 137 FERC ¶ 61,039 at P 68 (applying a screen excluding companies with recent merger and acquisition activity); *N. Pass Transmission, LLC,* 134 FERC ¶ 61,095 at P 46; *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 51)).

[218] *RITELine Ill., LLC,* 137 FERC ¶ 61,039 at P 68 (applying a screen excluding companies with recent merger and acquisition activity); *N. Pass Transmission, LLC,* 134 FERC ¶ 61,095 at P 46; *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 51.

[219] *Bangor Hydro-Elec. Co.*, 111 FERC ¶ 63,048 at PP 67-68, *aff'd in relevant part*, 117 FERC ¶ 61,129 (2006); *see also Atl. Grid Operations A LLC*, 135 FERC ¶ 61,144 at P 88 n.55; *Kern River*, 126 FERC ¶ 61,034 at PP 79-81.

[220] We note that, as discussed above, CH Energy Group is also eliminated from the proxy group due to a lack of IBES growth rate data.

[221] We note that no party filed briefs opposing the NETOs' elimination of Entergy Corp. and ITC Holdings Corp. due to their then-pending merger, nor to the elimination of CH Energy Group due to its acquisition by Fortis. Moreover, no party filed briefs proposing to eliminate additional proxies due to ongoing M&A activity.

these companies' announcements at the end of the study period impacted the DCF results by distorting the companies' stock prices, dividends, or growth rates.

6. High-End Outliers

i. Initial Decision

115. The Presiding Judge found that the NETOs' criteria for screening high-end outliers substantially complies with Commission precedent.[222] The Presiding Judge stated that Commission precedent requires the exclusion of cost of equity results where they fail "fundamental tests of reasonableness and economic logic."[223] The Presiding Judge further stated that the Commission's high-end outlier test since 2004 has been to exclude from the proxy group any company whose cost of equity estimate is at or above 17.7 percent and whose growth rate is at or above 13.3 percent.[224] The Presiding Judge asserted that for the DCF model to work properly both the high-end proxy group members and the low-end members must be appropriate. The Presiding Judge rejected Trial Staff's criticisms of the NETOs' high-end proxy group members and found that the NETOs provided a reasonable basis to support the inclusion of those companies.

ii. Briefs on Exceptions

116. Complainants state that the Initial Decision's adherence to a static 17.7 percent test that originated in 2003 conflicts with its references to "flexibility" and current "economic conditions" in raising the low-end threshold. Complainants further state that under the relevant Commission precedent there is already significant flexibility built into the low-end outlier test. Complainants contend that the Commission has never stated that the 17.7 percent high-end threshold is a static standard, but instead adopted that threshold in the context of a specific record that is now a decade old. Complainants argue that the

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[222] Initial Decision, 144 FERC ¶ 63,012 at P 571.

[223] *Id.* P 572 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 47; *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205).

[224] Initial Decision, 144 FERC ¶ 63,012 at P 572 (citing *ITC Holdings Corp.*, 121 FERC ¶ 61,229, at PP 28, 42 (2007); *Potomac-Appalachian Transmission Highline LLC*, 122 FERC ¶ 61,188, at P 100 (2008), *order on reh'g*, 133 FERC ¶ 61,152, at PP 20, 40, 64 (2010); *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 57; *S. Cal. Edison Co*., 139 FERC ¶ 61,042, at PP 54, 60; *RITELine Ill., LLC*, 137 FERC ¶ 61,039 at PP 68-73; *N. Pass Transmission LLC*, 134 FERC ¶ 61,095 at PP 46, 52-54).

Initial Decision should have confronted the evidence as to the appropriateness of a more current and stringent test, and that cases cited do not support adhering to a 17.7 percent high-end outlier test given current financial conditions.[225] The Complainants contend that the Presiding Judge should have updated the 17.7 percent high-end outlier test based on the change in bond yields since 2003. They contend that the 17.7 percent ROE rejected as unsustainable and illogical in Opinion No. 489[226] exceeded the contemporaneous average yield on 30-year public utilities by a factor of 3.12. Applying that same factor to the public utility bond yield for the relevant time period in this case would produce a high-end outlier test of 12.46 percent. EMCOS states that the Initial Decision mischaracterizes and ignores their witness testimony on outlier issues. EMCOS also states that the Initial Decision erroneously applies a fixed numerical threshold to define sustainable growth.[227]

iii. Briefs Opposing Exceptions

117. The NETOs state that the Commission does not reject IBES growth rates based on subjective opinions of witnesses. The NETOs also contend that the growth rates in their proxy group were well below the 13.3 percent level that the Commission views as unreasonable.[228]

iv. Commission Determination

118. Because we are adopting a two-step DCF methodology for determining the ROE for public utilities, we find that the high-end outlier issue in this proceeding is moot. Under the two-step DCF methodology, it is unnecessary to screen the proxy group for unsustainable growth rates because the methodology assumes that the long-term growth

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[225] Complainants Brief on Exceptions at 48-49; 82-85 (citing *ITC Holdings Corp.*, 121 FERC ¶ 61,229; *Potomac-Appalachian Transmission Highline LLC*, 122 FERC ¶ 61,188 at P 100, *order on reh'g*, 133 FERC ¶ 61,152 at PP 20, 40, 64; *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 57; *S. Cal. Edison Co.*, 139 FERC ¶ 61,042 at PP 54, 60; *RITELine Ill., LLC*, 137 FERC ¶ 61,039 at PP 68-73; *N. Pass Transmission LLC*, 134 FERC ¶ 61,095 at PP 46, 52-54).

[226] Opinion No. 489, 117 FERC ¶ 61,129 at P 24; *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205.

[227] EMCOS Brief on Exceptions at 30-37.

[228] NETOs Brief Opposing Exceptions at 33.

rate for each company is equal to GDP. As a result, no company in the proxy group we are adopting here has a composite growth rate under the two-step DCF methodology in excess of the 7.66 percent growth rate of PNM Resources, Inc., or an ROE in excess of the 11.74 percent ROE of UIL Holdings. And those percentages are well within any high-end outlier test we have previously applied in utility rate cases and are within the high-end outlier test advocated by the Complainants on exceptions.

7. Low-End Outliers

i. Initial Decision

119. The Presiding Judge found that the NETOs' criteria for excluding low-end outliers in this case substantially complies with Commission precedent,[229] which requires the exclusion of companies whose cost of equity estimates fail tests of reasonableness and economic logic.[230] The Presiding Judge noted that, although it may be reasonable to exclude any company whose low-end ROE estimate fails to exceed the average bond yield by about 100 basis points or more, a flexible application of the low-end outlier test is appropriate because the Commission has not established an economic rationale supporting strict application of the 100 basis point figure.[231]

ii. Briefs on Exceptions

120. Trial Staff states that the NETOs incorrectly followed the Commission's well-established rule for excluding any companies whose ROE results fail to exceed the six-month average Moody's bond yield for the relevant rating category by about 100 basis points. Trial Staff notes that the NETOs correctly eliminated four companies which were under the 100 basis points threshold, but argues that they should not have eliminated Edison International (Edison), which had a low-end result of 5.9 percent, since they did not eliminate Cleco, which had a low-end result of 6.0 percent. Instead, Trial Staff contends that the "natural break" is between the 2.7 percent low-end result of Pacific Gas & Electric and the 5.9 percent low-end result of Edison.

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[229] Initial Decision, 144 FERC ¶ 63,012 at P 571.

[230] *Id.* P 572 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 57; *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205).

[231] Initial Decision, 144 FERC ¶ 63,012 at P 573 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 55).

iii. Briefs Opposing Exceptions

121. In reference to the inclusion of Edison's low-end DCF result, the NETOs argue that there is no strict rule requiring the exclusion of any low-end cost of equity estimate that fails to exceed the average bond yield by 100 basis points. The NETOs argue that the flexible application of the low-end outlier test is consistent "with the Commission directive that low-end DCF results should be eliminated if they are somewhat above the average bond yield, but still sufficiently low that an investor would consider the stock to yield essentially the same return."[232] The NETOs argue that it is appropriate to set the low-end outlier threshold for the refund period slightly more than 100 basis points above utility bond yields given the economic conditions and downward bias on utility bond yields during the relevant time period.[233]

iv. Commission Determination

122. As the Presiding Judge correctly explained, the Commission's low-end outlier test for the one-step DCF methodology in recent years has been to exclude any company whose low-end ROE fails to exceed the average bond yield by some amount of basis points, taking into account the company's ROE estimate relative to the estimates of the other proxy group companies.[234] The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt.[235] In public utility ROE cases, the Commission has used 100 basis points above the cost of debt as an approximation of this threshold, but has also considered the distribution of proxy group companies to inform its decision on which companies are outliers. As the Presiding Judge explained, this is a flexible test. We therefore affirm the Initial Decision in this respect.

123. Applying the low-end outlier test in the instant proceeding results in the elimination of three companies from the proxy group. The Moody's Baa average for the

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[232] NETOs Brief Opposing Exceptions at 67 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 55).

[233] NETOs Brief Opposing Exceptions at 67.

[234] Initial Decision, 144 FERC ¶ 63,012 at P 573 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 55).

[235] *See S. Cal Edison Co.*, 92 FERC at 61,266.

six-month study period ending March 2013 is 4.61 percent. Therefore, we find it appropriate to exclude from the proxy group any company with a cost of equity estimate of approximately 5.61 percent or lower. Accordingly, we eliminate the following companies as low-end outliers: Edison (3.11 percent); Ameren Corp. (5.26 percent); and Public Service Enterprise Group Inc., whose 5.62 percent cost of equity estimate is an insignificant single basis point above the 100 basis point threshold. Our decision to exclude these companies from the proxy group is buttressed by the fact that there is a natural break between the cost of equity estimates of the companies we exclude from the proxy group and the lowest cost of equity estimate of the companies we include in the proxy group, i.e., the 7.03 percent cost of equity estimate of El Paso Electric Co. The 5.62 percent cost of equity estimate of Public Service Enterprise Group Inc, is only 101 basis point above the applicable bond yield, while the 7.03 percent cost of equity estimate of El Paso Electric Co. is 242 basis points above the applicable bond yield. Thus, there is a 141 basis point break between the companies we exclude from the proxy group as low-end outliers and the companies we include in the proxy group.

8. Summary

124. In summary, of the 49 companies in the NETOs' starting proxy group,[236] 11 companies fail the above proxy group screens and are, therefore, eliminated from the proxy group. We eliminate one company – CH Energy Group, Inc. – because no IBES growth rate data is available for that company.[237] We eliminate two companies – Entergy Corp. and ITC Holdings Corp. – due to M&A activity. We eliminate four companies – MGE Energy, Inc., NV Energy, Inc., PNM Resources, Inc., and Unisource Energy Corp.

[236] The 49 companies in our starting proxy group are as follows: ALLETE, Inc.; Alliant Energy Corp.; Ameren Corp.; American Electric Power Co., Inc.; Avista Corp.; Black Hills Corp.; CenterPoint Energy, Inc.; CH Energy Group, Inc.; Cleco Corp.; CMS Energy Corp.; Consolidated Edison, Inc.; Dominion Resources, Inc.; DTE Energy Co.; Duke Energy Corp.; Edison International; El Paso Electric Co.; Empire District Electric Co.; Entergy Corp.; Exelon Corp.; FirstEnergy Corp.; Great Plains Energy Inc.; Hawaiian Electric Industries, Inc.; IDACORP, Inc.; Integrys Energy Group, Inc.; ITC Holdings Corp.; MGE Energy, Inc.; NextEra Energy, Inc.; Northeast Utilities; NorthWestern Corp.; NV Energy, Inc.; OGE Energy Corp.; Otter Tail Corp.; Pepco Holdings, Inc.; PG&E Corp.; Pinnacle West Capital Corp.; PNM Resources, Inc.; Portland General Electric Co.; PPL Corp.; Public Service Enterprise Group Inc.; SCANA Corp.; Sempra Energy; Southern Company; TECO Energy, Inc.; UIL Holdings Corp.; Unisource Energy Corp.; Vectren Corp.; Westar Energy, Inc.; Wisconsin Energy Corp.; Xcel Energy, Inc.

[237] We note that CH Energy Corp. would also fail the M&A screen.

– because their credit ratings fall outside either the Moody's or S&P credit risk bands. We eliminate one company – Exelon Corp. – due to its dividend cut within the 6-month study period.[238] Lastly, we eliminate three companies – Ameren Corp., Edison International, and Public Service Enterprise Group Inc. – as low-end outliers.

125. After eliminating these 11 companies, 38 companies remain in our final proxy group.[239] Based on the record developed thus far in this proceeding, the zone of reasonableness produced by those 38 companies is 7.03 percent to 11.74 percent, as shown in the Appendix to this order.[240] As noted above, this is a tentative finding, based on the 4.39 percent GDP value we use in our DCF analysis,[241] and is subject to any further record evidence submitted in the paper hearing on the long-term growth issue.

C. Placement of the Base ROE within the Zone of Reasonableness

1. Initial Decision

126. The Presiding Judge agreed with the NETOs that the just and reasonable base ROE should be based on the market conditions during the relevant time period, but concluded that the DCF analysis considers market conditions.[242] Accordingly, the

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[238] We note that Exelon Corp. would also be eliminated as a low-end outlier.

[239] The 38 companies in our final proxy group are as follows: ALLETE, Inc.; Alliant Energy Corp.; American Electric Power Co., Inc.; Avista Corp.; Black Hills Corp.; CenterPoint Energy, Inc.; Cleco Corp.; CMS Energy Corp.; Consolidated Edison, Inc.; Dominion Resources, Inc.; DTE Energy Co.; Duke Energy Corp.; El Paso Electric Co.; Empire District Electric Co.; FirstEnergy Corp.; Great Plains Energy Inc.; Hawaiian Electric Industries, Inc.; IDACORP, Inc.; Integrys Energy Group, Inc.; NextEra Energy, Inc.; Northeast Utilities; NorthWestern Corp.; OGE Energy Corp.; Otter Tail Corp.; Pepco Holdings, Inc.; PG&E Corp.; Pinnacle West Capital Corp.; Portland General Electric Co.; PPL Corp.; SCANA Corp.; Sempra Energy; Southern Company; TECO Energy, Inc.; UIL Holdings Corp.; Vectren Corp.; Westar Energy, Inc.; Wisconsin Energy Corp.; Xcel Energy, Inc.

[240] The DCF result for El Paso Electric Co. set the bottom of the zone at 7.03 percent, and the DCF result for UIL Holdings Corp. set the top of the zone at 11.74 percent.

[241] *See* Appendix (explaining our calculation of the 4.39 percent GDP value).

[242] Initial Decision, 144 FERC ¶ 63,012 at P 548.

Presiding Judge found it appropriate to set the just and reasonable rate at the midpoint of the zone of reasonableness,[243] and rejected the NETOs' contention that the base ROE should be set halfway between the midpoint and the top of the zone of reasonableness.[244]

127. The Presiding Judge rejected the NETOs' contention that the traditional DCF methodology understated their true cost of equity and that alternative methodologies should be considered.[245] The Presiding Judge noted, however, that the Commission may consider alternative methods if necessary to adjust the ROE based on the legal and policy considerations expressed in *Hope* and *Bluefield*.[246] The Presiding Judge stated that, if the ROE is set substantially below 10 percent for long periods of time, it could negatively impact future investment in transmission and thereby negatively impact operational needs, reliability, and ratepayers' future costs.[247] The Presiding Judge further noted that current capital market conditions are a relevant consideration in formulating the appropriate ROE in this proceeding.[248] The Presiding Judge also explained that all expert witnesses in this proceeding deviated from the traditional DCF analysis for a variety of reasons including, "to make pragmatic adjustments to the DCF economic analysis theory during a rather volatile and unstable economic period."[249]

2. Briefs on Exceptions

128. The NETOs assert that setting the just and reasonable base ROE depends on the facts of each case and, while the Commission generally uses the midpoint of the zone of reasonableness when establishing the base ROE for a diverse group of utilities, the Commission has acknowledged that the base ROE may be set above the midpoint when warranted.[250] The NETOs argue that it is appropriate to set the base ROE in this

[243] *Id.* PP 590-591.

[244] *Id.* P 591.

[245] *Id.* P 549.

[246] *Id.* P 575.

[247] *Id.* P 576.

[248] *Id.* P 580.

[249] *Id.* P 595.

[250] NETOs Brief on Exceptions at 22 (citing *S. Cal. Edison Co.*, 92 FERC ¶ 61,070).

proceeding halfway between the midpoint and the top of the zone of reasonableness. The NETOs assert that, in declining to set the base ROE halfway up the top half of the zone, the Initial Decision failed to consider the Commission's policy on transmission investment, the extraordinary conditions in the credit markets, and the results of other alternative benchmark methodologies to the electric utility DCF analysis.

129. The NETOs argue that the Initial Decision also erred by not taking into account the effect that the "highly unusual market conditions" had on the DCF results, and that unusually low interest rates caused "abnormal, low-end results that unrealistically depress the ROE midpoint."[251] The NETOs state that capital market conditions at the time of the proceeding were anomalous, that 10-year Treasury bond yields were the lowest they have been since 1941 and yields on public utility bonds have been at their lowest levels in over thirty years.[252]

130. The NETOs further contend that capital market conditions are expected to change significantly in the near-term,[253] and strict reliance on the DCF methodology will result in ROEs "that are insufficient to attract investment on reasonable terms."[254] The NETOs argue that once the Federal Reserve's Quantitative Easing program ends, "which may be in the very near future, interest rates can be expected to rise to more normal levels," and bond levels can be expected to increase.[255] The NETOs assert that the Commission should take into account the evidence regarding low interest rates, how those interest rates depressed the ROE midpoint, and how interest rates will rise in the near-term, and then set the ROEs in the upper range of the zone.[256] The NETOs assert that, because the DCF analysis is meant to reflect the rate of return needed to attract investors going forward, data showing increasing interest rates and cost of capital is particularly relevant.[257]

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[251] NETOs Brief on Exceptions at 31–32.

[252] *Id.* at 33.

[253] *Id.* at 32.

[254] *Id.*

[255] *Id.* at 34.

[256] *Id.* at 32–33.

[257] *Id.* at 35.

131. The NETOs argue that five alternative benchmark methodologies—the capital asset pricing model (CAPM), risk premium analysis, natural gas pipeline ROE, non-utility DCF analysis, and expected earnings analysis—provide additional information that would benefit the Commission's ROE analysis by showing that the existing 11.14 percent base ROE is just and reasonable and that the DCF analysis alone produces distorted results.[258] The NETOs note that since all models have shortcomings, it is appropriate to test DCF results against a number of other models and benchmarks in order to arrive at the soundest conclusion possible.[259]

132. Trial Staff argues that the Presiding Judge erred in stating that, if the ROE is set substantially below 10 percent for long periods, it could negatively impact future investment in the NETOs.[260] Trial Staff argues that an unqualified numerical ROE "floor" is inappropriate and ignores the value of financial estimation techniques used to estimate the cost of capital.[261] Trial Staff further states that the 10 percent floor was in part based on state-allowed ROEs which the Commission has rejected in light of its exclusive jurisdiction in this area.[262] Trial Staff states that the DCF model is based on actual, observed market data, and that the testimony on the alternative methodologies is not probative.[263]

133. Complainants note that, because the cost of capital varies over time, allowed ROEs must vary over time in order to remain cost-based.[264] Complainants argue that the method adopted by the Initial Decision "is incapable of tracking actual capital costs when they fall substantially below 10 [percent]."[265] Complainants argue that the opinion

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[258] *Id.* at 36-37.

[259] *Id.* at 38 (citing NET-300 at 47-49; *Distrigas of Mass. Corp.*, 41 FERC ¶ 61,205, at 61,550-51 (1987); *S. Cal. Edison Co.*, 92 FERC at 61,260-61,267).

[260] Trial Staff Brief on Exceptions at 57.

[261] *Id.*

[262] *Id.*

[263] *Id.* at 58–59.

[264] Complainants Brief on Exceptions at 78–79 (citing *Hope*, 320 U.S. at 615; *Bluefield*, 262 U.S. at 692-93).

[265] Complainants Brief on Exceptions at 79.

expressed in the Initial Decision that an ROE of less than 10 percent for long periods could negatively impact future investment has no basis, and that investment will not be impeded if the actual cost of equity falls below 10 percent.[266]

3. Briefs Opposing Exceptions

134. EMCOS and Trial Staff argue that the base ROE should not be set halfway between the midpoint and the top end of the zone of reasonableness, but should instead be set at the midpoint, consistent with the Commission's traditional DCF methodology. EMCOS state that the base ROE need not be adjusted upwards to counteract alleged distortions caused by the traditional DCF methodology and allegedly anomalous economic conditions, or to further the Commission's transmission investment policies. Trial Staff contends that the public policy considerations that NETOs argue require a base ROE above the midpoint are weighed in determining incentive rates, which are not at issue in this case. Similarly, EMCOS state that the traditional DCF methodology is designed to encourage transmission investment and ROE adders are available if the base ROE fails to do so.

135. Trial Staff asserts that the base ROE should be set according to cost of service ratemaking principles and should reflect investors' required return, i.e., the cost of equity capital. EMCOS states that the base ROE should be set based on current market conditions, not based on predictions that economic conditions could significantly change in the future. EMCOS states that the Commission has previously rejected the argument that current economic conditions are abnormal and have caused DCF results that are too low.[267] EMCOS further notes that should the NETOs' economic prediction come to fruition, they may then make a section 205 filing requesting a rate increase, but until then "rate payers should pay rates that reflect the actual economy."[268]

136. Trial Staff argues that the NETOs' proposed alternative methodologies do not result in a just and reasonable base ROE in this proceeding, due to flawed execution and unreliable or inappropriate data. Trial Staff explains that the Commission has consistently

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[266] *Id.*

[267] EMCOS Brief Opposing Exceptions at 15 (citing Opinion No. 524, 142 FERC ¶ 61,197 at P 233).

[268] EMCOS Brief Opposing Exceptions at 15, 24–25.

rejected the proffered use of financial models other than the traditional DCF analysis.[269] Trial Staff contends that relying on past ROEs or risk premium relationships to impute an expected investor return today, as do some of the alternative methodologies, produces circular results that are theoretically inferior measures of current investor-required equity returns. Trial Staff further contends that, because the data used in the alternative methodologies are not screened based on relative risk, these methods also do not produce ROEs which are relevant to the NETOs' risks. Complainants argue that the Commission has continued to find that non-DCF approaches to determining transmission ROE are "unlikely to produce a just and reasonable result," and that its "preference for the one-step DCF analysis in determining the appropriate ROE for electric utility companies" is well-settled and recently reaffirmed.[270]

137. The NETOs agree with the Presiding Judge that, if the ROE is set substantially below 10 percent for long periods, it could negatively impact future investment, because "investors will expect a somewhat higher return for investment in transmission as compared to investment in state jurisdictional activities," due to the higher risks associated with transmission investment.[271] The NETOs argue that, because the central tendency of state-level ROEs has been around 10 percent to 10.5 percent, an ROE at or below these levels would materially reduce investment.[272] The NETOs assert that the Initial Decision did not establish an ROE floor of 10 percent, but instead simply found that there was "probative value to the argument that an ROE set below 10 [percent] could negatively impact future investment in the NETOs."[273]

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[269] Trial Staff Brief Opposing Exceptions at 36-38 (citing *Allegheny Power*, Opinion No. 469, 106 FERC ¶ 61,241 P 24, *reh'g denied,* Opinion No. 469-A, 108 FERC ¶ 61,151 (2004), *dismissed in part vacated in part and remanded sub nom. Allegheny Power v. FERC*, 437 F.3d 1219 (D.C. Cir. 2006); *Sys. Energy Resources, Inc.*, Opinion No. 446, 92 FERC at 61,446; Opinion No. 445, 92 FERC at 61,260-63).

[270] Complainants Brief Opposing Exceptions at 57 (citing *Xcel Energy Servs., Inc.*, 122 FERC ¶ 61,098, at P 73, *clarified*, 125 FERC ¶ 61,092 (2008); Order No. 679, FERC Stats. & Regs. ¶ 31,222 at PP 99, 102).

[271] NETOs Brief Opposing Exceptions at 95 (citing Ex. NET-600 at 37-38; Tr. 454:25-455:3, 856:3-6; Ex. NET-400 at 26; Tr. 455:4-6, 855:23-856:9).

[272] NETOs Brief Opposing Exceptions at 96.

[273] *Id.* at 98 (citing Initial Decision, 144 FERC ¶ 63,012 at P 576).

138. Complainants argue that "Commission precedent requires 'highly unusual circumstances indicating anomalously high or low risk factors and a very persuasive demonstration' before a base ROE can properly be adjusted upwards from the center of the DCF results," and that NETOs' prediction of market changes falls short of these standards.[274]

139. Complainants take issue with NETOs' claim that low bond yields results in higher utility stock prices and lower dividend yields, arguing that "investors' comparison-shopping makes them willing to accept lower equity returns when debt yields are low."[275] Complainants argue that the DCF analysis process takes that effect into account and its doing so does not result in anything abnormal or unrealistic.[276]

140. Complainants take issue with NETOs' claim that the DCF-estimated ROE should be adjusted upwards due to anticipated interest rate increases since the core DCF method is to infer the return term from share prices paid in the past six months, and argues that "expectations about the pace and vigor of economic recovery, and of associated Federal Reserve monetary policy, are already baked into study-period share prices and analysts' forecasts of the proxies' future earnings."[277] Complainants argue that when the Commission *has* attributed a higher ROE than the DCF results, it was because the utility was substantially riskier than the proxies; but here, Complainants argue, the NETOs are less risky than the proxy group on which the Initial Decision relied and NETOs have "not made the 'very persuasive' showing of greater risk that precedent requires as a precondition to placing a base ROE above the DCF center."[278]

141. Complainants argue that predictions of capital market changes cannot justify raising the ROE in this proceeding.[279] Complainants take issue with NETOs' efforts "to shift the focus of this proceeding to the returns they expect will be demanded by the

[274] Complainants Brief Opposing Exceptions at 42 (citing Opinion No. 524, 142 FERC ¶ 61,198 at P 241).

[275] Complainants Brief Opposing Exceptions at 43–44.

[276] *Id.* at 44.

[277] *Id.* at 47–48.

[278] *Id.* at 48–49 (citing Opinion No. 524, 142 FERC ¶ 61,198 at P 241).

[279] Complainants Brief Opposing Exceptions at 49.

investors of 2017."[280] Complainants argue that, if NETOs' predictions are correct, it will have the opportunity to then file for a rate increase; the Commission's decision-making in the meantime, however, "requires reference to the DCF results of record, not predictions of how capital costs may rise by 2017."[281]

4. Commission Determination

142. We acknowledge that under the DCF analysis, the Commission typically sets the base ROE with regard to multiple entities at the midpoint of the zone of reasonableness. However, for the reasons set forth below, we conclude that a mechanical application of the DCF methodology with the use of the midpoint here would result in an ROE that does not satisfy the requirements of *Hope* and *Bluefield*. Therefore, based on the record in this case, including the unusual capital market conditions present, we conclude that the just and reasonable base ROE for the NETOs should be set halfway between the midpoint of the zone of reasonableness and the top of the zone of reasonableness. Based on the record thus far in this proceeding, we tentatively find that the just and reasonable base ROE for the NETOs is 10.57 percent, which is halfway between the 9.39 percent midpoint of the zone of reasonableness and the 11.74 percent top of that zone. This finding is tentative because it is subject to the submission of the record evidence at the paper hearing, described below, as to the appropriate long-term growth rate given our adoption of the two-step DCF methodology.

143. Having applied the DCF model and risk screens to develop a proxy group and estimate the zone of reasonable ROEs for similar companies – a zone of 7.03 percent to 11.74 percent – the Commission must next determine where to place the just and reasonable ROE within that zone of reasonableness. *Hope* once again sets forth the principle guiding this determination: the just and reasonable ROE should be "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[282]

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[280] *Id.* at 50.

[281] *Id.*

[282] *Hope*, 320 U.S. at 603; *see also Bluefield*, 262 U.S. at 693 ("The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties."). *Cf. supra* P 102 (describing the NETOs' competition with other utilities and other non-utility companies to attract capital).

144. While the Commission has previously found the midpoint of the zone of reasonableness to be the appropriate measure of central tendency for determining the base ROE for a diverse group of utilities (as opposed to the median, used for a single utility),[283] the midpoint does not represent a just and reasonable outcome *if* the midpoint does not appropriately represent the utilities' risks.[284] The Commission's ultimate task is to ensure that the resulting ROE satisfies the requirements of *Hope* and *Bluefield*.

145. Parties on both sides of the instant ROE issue argue that the unique capital market conditions have impacted the level of equity return the NETOs' require to meet the capital attraction standards of *Hope* and *Bluefield*.[285] We are concerned that capital market conditions in the record are anomalous, thereby making it more difficult to determine the return necessary for public utilities to attract capital. In these circumstances, we have less confidence that the midpoint of the zone of reasonableness established in this proceeding accurately reflects the equity returns necessary to meet the *Hope* and *Bluefield* capital attraction standards.[286] We find it is necessary and reasonable to consider additional record evidence, including evidence of alternative benchmark

[283] *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 91, *remanded on other grounds sub nom. S. Cal. Edison Co. v. FERC*, 717 F.3d 177.

[284] *See Petal Gas*, 496 F.3d at 699.

[285] *See, e.g.*, Ex. C-1, 5-6 (Test. of Complainants' witness Woolridge); NETOs Brief on Exceptions at 32. For example, bond yields are at historic lows, with the yield on U.S. Treasury bonds during the six-month study period ending March 2013 below 2 percent. Ex. NET-405; Ex. NET-400 at 32-33. Until the financial crisis of 2008, the yield on U.S. Treasury bonds had not fallen below 3 percent since the 1950s. Ex. NET-450. U.S. Treasury bond yields are not an input in the DCF model, but they reflect current capital market conditions, which could have an indirect impact on the two inputs in the DCF model—dividend yield and growth rate.

[286] As the NETOs' witness Lapson testified, "There is 'model risk' associated with the excessive reliance or mechanical application of a model when the surrounding conditions are outside of the normal range. 'Model risk' is the risk that a theoretical model that is used to value real-world transactions fails to predict or represent the real phenomenon that is being modeled." Ex. NET-400 at 40.

methodologies and state commission-approved ROEs, to gain insight into the potential impacts of these unusual capital market conditions on the appropriateness of using the resulting midpoint. [287]

146. The NETOs presented five alternative benchmark methodologies in this proceeding: risk premium analysis, the CAPM, comparison of electric ROEs with natural gas pipeline ROEs, comparison of electric utility DCF results with non-utility DCF results, and expected earnings analysis. Of those five, we find the risk premium analysis, the CAPM, and expected earnings analyses informative,[288] and each produces a midpoint (or median) ROE higher than the midpoint of our DCF analysis here. In considering these other methodologies, we do not depart from our use of the DCF methodology; rather, we use the record evidence to inform the just and reasonable placement of the ROE within the zone of reasonableness established in the record by the DCF methodology.

147. The risk premium methodology, in which interest rates are a direct input, is "based on the simple idea that since investors in stocks take greater risk than investors in bonds, the former expect to earn a return on a stock investment that reflects a 'premium' over and above the return they expect to earn on a bond investment."[289] As the NETOs explain, investors' required risk premiums expand with low interest rates and shrink at higher interest rates. The link between interest rates and risk premiums provides a helpful indicator of how investors' required returns on equity have been impacted by the

[287] *See, e.g., Distrigas of Mass. Corp.*, 41 FERC at 61,550 ("The DCF methodology, which we endorse, is but one analytical tool. A risk premium analysis, . . . will also be considered. The weight to be given the results of each such methodology rests on the accuracy and sensibleness of the judgmental imputs [*sic*] and factors that the respective witnesses employed."); *see also,* Roger A. Morin, New Regulatory Finance at 428-430 (Public Utilities Reports, Inc. 2006) (The results from one methodology . . . may be distorted by short-term aberrations.).

[288] We will not consider the non-utility DCF analysis or the natural gas pipeline ROE analysis because those methodologies are not based on electric utilities.

[289] Roger A. Morin, New Regulatory Finance 108 (Public Utilities Reports, Inc. 2006). CAPM estimates risk premiums indirectly, whereas the risk premium analysis methodology develops risk premiums directly. *Id.* at 110.

interest rate environment.[290] The NETOs' risk premium analysis indicates that the NETOs cost of equity is between 10.7 percent and 10.8 percent, which is higher than the 9.39 percent midpoint produced by our DCF analysis.[291] Similar to the risk premium analysis, the NETOs' CAPM uses interest rates as the input for the risk-free rate, which makes it useful in determining how the interest rate environment has impacted investors' required returns on equity.[292] Further, CAPM is utilized by investors as a measure of the cost of equity relative to its risk. Using the same proxy companies from our DCF analysis, before screening for low-end outliers, the NETOs' CAPM analysis produces an ROE range of 7.4 percent to 13.3 percent, with a midpoint value of 10.4 percent and a median value of 10.9 percent.[293] Finally, the NETOs' expected earnings analysis, given its close relationship to the comparable earnings standard that originated in *Hope*, and the fact that it is used by investors to estimate the ROE that a utility will earn in the future can be useful in validating our ROE recommendation.[294] Once again using the same proxy group that we used in our DCF analysis, the expected earnings analysis has an

[290] While the Commission has in the past rejected the use of risk premium analyses to estimate investor-required returns on equity, those cases are distinguishable from the instant proceeding because they involved proposals to establish a constant risk premium based on the average difference between state commission ROEs and bond rates over multi-year periods. *See New England Power Co.*, 31 FERC ¶ 61,378, at 61,841-42 (1985); *Boston Edison Co.*, Opinion No. 411, 77 FERC at 62,171-72, *aff'g in relevant part*, 66 FERC at 65,075-76, *remanded on other grounds sub nom. Boston Edison Co. v. FERC*, 233 F.3d 60 (2000); *Jersey Cent. Power & Light Co.*, 77 FERC at 61,007; *N. Ind. Pub. Serv. Co., Inc.*, 101 FERC ¶ 61,394, at P 38 (2002).

[291] *See* NETOs Brief on Exceptions at 44.

[292] While the Commission has in the past rejected the use of CAPM analyses, those cases are distinguishable from the instant proceeding because they involved CAPM analyses that were based on historic market risk premiums, *see, e.g.*, *ITC Holdings Corp., et al. v. Interstate Power and Light Co. and Midwest Indep. Sys. Op., Inc.*, 121 FERC ¶ 61,229, at P 43 n.37 (2007), whereas the NETOs' CAPM analysis is based on forward-looking investor expectations for the market risk premium.

[293] Ex. NET-708. While NETO's exhibit does not provide a median value, we calculate it to be 10.4 percent using the 41 companies in our DCF analysis.

[294] Roger A. Morin, New Regulatory Finance 381 (Public Utilities Reports, Inc. 2006). The comparable earning standard uses the return earned on book equity by enterprises of comparable risk as the measure of fair return. *Id.*

ROE range of 8.1 percent to 16.1 percent, with a midpoint value of 12.1 percent and a median value of 10.2 percent.[295] The record evidence from each of these models affirms our setting the ROE at a point above the midpoint under these circumstances.

148. In addition, other record evidence of state commission-approved ROEs supports adjusting the ROE to a point halfway up the upper half of the zone of reasonableness in this case. The Commission has repeatedly held that it does not establish utilities' ROE based on state commission ROEs for state-regulated electric distribution assets, because those ROEs are "established at different times in different jurisdictions which use different policies, standards, and methodologies in setting rates."[296] The wisdom of that rationale is no less applicable now than in the Commission's earlier cases. However, in this proceeding, we are faced with circumstances under which the midpoint of the zone of reasonableness established in this proceeding has fallen below state commission-approved ROEs, even though transmission entails unique risks that state-regulated electric distribution does not. While the midpoint in this case is 9.39 percent, the record indicates that, over the 24-month period from October 1, 2010 through September 30, 2012, approximately 85 percent to 91 percent of state commission authorized ROEs were between 9.8 percent and 10.74 percent.[297] Although we are not using state commission-approved ROEs to establish the NETOs' ROE in this proceeding, the discrepancy between state ROEs and the 9.39 percent midpoint serves as an indicator that an upward adjustment to the midpoint here is necessary to satisfy *Hope* and *Bluefield*.

149. The financial and business risks faced by investors in companies whose focus is electric transmission infrastructure differ in some key respects when compared to other electric infrastructure investment, particularly state-regulated electric distribution. For example, investors providing capital for electric transmission infrastructure face risks including the following: long delays in transmission siting, greater project complexity, environmental impact proceedings, requiring regulatory approval from multiple jurisdictions overseeing permits and rights of way, liquidity risk from financing projects

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[295] Ex. NET-709. While the NETOs' exhibit does not provide a median value, we calculate it to be 10.2 percent using the 41 companies in our DCF analysis.

[296] *Middle South Services, Inc.*, Opinion No. 124, 16 FERC ¶ 61,101, at 61,221 (1981); *see also Boston Edison Co.*, Opinion No. 411, 77 FERC ¶ 61,272, at 62,171-62,172 (1996); *Jersey Cent. Power & Light Co.*, Opinion No. 408, 77 FERC at 61,002.

[297] Ex. NET-400 at 26-27 (citing Ex. NET-402; Ex. NET-403); *see also* Ex. NET-400 at 13 ("Individual transmission tariffs decided since 2006 have typically included base-level ROEs that . . . were within or above the high end of the range of returns available in state jurisdictions.").

that are large relative to the size of a balance sheet, and shorter investment history.[298] We find that these factors increase the NETOs' risk relative to the state-regulated distribution companies. However, as noted above, the record in this proceeding indicates that the vast majority of state commission-authorized ROEs reflected on this record range from 9.8 percent to 10.74 percent,[299] and our DCF analysis in this proceeding produces a midpoint of 9.39 percent, we find that the record evidence concerning state commission authorized ROEs supports setting the NETOs' base ROE above the midpoint.

150. Our obligation as a Commission is to ensure that we meet the requirements of *Hope* and *Bluefield* that ROE be set at a level sufficient to attract investment in interstate electric transmission. Such investment helps promote efficient and competitive electricity markets, reduce costly congestion, enhance reliability, and allow access to new energy resources, including renewables.[300] While a mechanical application of the two-step constant growth DCF methodology produces a midpoint of 9.39 percent in the anomalous capital market conditions reflected in the record, there is also record evidence that a decrease in ROE of that magnitude (down from 11.14 percent) could undermine the ability of the NETOs to attract capital for new investment in electric transmission.[301] As discussed above, a 9.39 percent ROE would be generally below the ROEs set by state commissions for electric utilities within their jurisdiction. Reducing the NETOs' ROE to that level "would put interstate transmission [investments] at a competitive disadvantage in the capital market in contrast with more conventional electric utility activities."[302] In addition, such a reduction in ROE could lead investors to view investments in interstate

[298] *See* Ex. NET-400 at 10-15, n.12; NETOs Brief Opposing Exceptions at 95-97.

[299] Ex. NET-400 at 26-27 (citing Ex. NET-402; Ex. NET-403).

[300] *See* Ex. NET-400 at 19-23 and 30-31.

[301] *Id*. at 16-19. For example, the NETOs' witness pointed out that a May 3, 2012 UBS Investment Research sector comment stated, "We believe companies will redeploy capital elsewhere if transmission returns are materially reduced. In our view, the cost of capital could actually increase, because as returns are set lower, valuation multiples will also be reset much lower than current levels. Additionally, the second order effects on other state and Federal government policy objectives, i.e. renewables development, could be significant, in our view." *Id*. at 18.

[302] *Id*. at 24.

transmission as more unstable, diminishing "investors' confidence in FERC jurisdictional investment in transmission."[303]

151. In these circumstances, we find that the NETOs should be awarded an ROE above the midpoint of the zone of reasonableness established by our DCF analysis. The Commission has traditionally looked to the central tendency to identify the appropriate return within the zone of reasonableness.[304] Similarly, we believe that here in selecting the appropriate return we likewise should look to the central tendency to identify the appropriate return but, in light of the record in this proceeding, we should look to the central tendency for the top half of the zone of reasonableness,[305] thus identifying an appropriate return reflective of capital market conditions in the record and the need to meet the capital attraction standards of *Hope* and *Bluefield*. And thus, we will set the NETOs' ROE at the point that is halfway between the midpoint of the zone of reasonableness and the top of the zone.[306]

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[303] *Id*. at 43. *See also* Ex. NET-600 at 42 ("In my professional opinion, cutting the base ROE by approximately 150 basis points . . . would undermine the favorable access to capital that currently allows for and fosters major development of transmission infrastructure by transmission owners throughout the United States. Strong cash flow and healthy levels of return produce the corporate financial resources that allow utilities such as the NETOs to enter into multi-year commitments to fund major capital investments with both equity and debt, without regard to the cycles in capital and banking markets. . . .A steep reduction in base ROE will affect the capital market appeal of electric transmission investment by the NETOs and other utilities across the nation.").

[304] *See generally, e.g., Midwest Independent Transmission System Operator, Inc.*, 106 FERC ¶ 61,302, at P 10 (2004) (given a range of returns, the "most appropriate" and "most just and reasonable" single return that best considers that range is the central tendency), *aff'd in relevant part sub nom. Pub. Serv. Comm'n of Ky. v. FERC*, 397 F.3d 1004, 1010-11 (D.C. Cir. 2005).

[305] *See infra* P 156 (explaining that the participants have had a full opportunity to submit evidence on the placement of the base ROE above the midpoint of the zone of reasonableness, and contest the evidence relied upon in our finding that it is appropriate to place the base ROE halfway between the midpoint of the zone of reasonableness and the top of that zone).

[306] Concurrently with this opinion we are setting for trial-type evidentiary hearings and settlement judge procedures other pending cases where the issue is the appropriate ROE. Nothing in this order precludes participants in those proceedings from developing a record in those cases supporting a different point in the range of reasonable returns than

(continued…)

152. In sum, based on the record evidence in this case, including the unusual capital market conditions present, we find that, to ensure a base ROE that satisfies the *Hope* and *Bluefield* standards under these circumstances, a base ROE in the upper half of the zone of reasonableness represents a just and reasonable base ROE for the NETOs. When placing a base ROE above the central tendency of the zone of reasonableness, the Commission has in the past placed the base ROE at the midpoint of the upper half of the zone.[307] We, therefore, find that a base ROE halfway between the midpoint of the zone of reasonableness and the top of that zone represents a just and reasonable ROE for the NETOs. Accordingly, based on the record evidence thus far in this proceeding, we tentatively find that a base ROE of 10.57 percent, the point halfway between the 9.39 percent midpoint of the zone of reasonableness and the 11.74 percent top of that zone, is appropriate for the NETOs. As noted, our finding concerning the specific numerical just and reasonable ROE for the NETOs is subject to the outcome of the paper hearing on the appropriate long-term growth projection to be used in the two-step DCF methodology.

153. EMCOS argues that the NETOs' base ROE should not be placed above the midpoint because the DCF methodology is designed to encourage transmission investment and ROE adders are available if the base ROE fails in that respect. Similarly, Trial Staff argues that it is inappropriate to place the NETOs' base ROE above the midpoint because the policy considerations for doing so are weighed in determining incentive rates. We reject both of these arguments. The purpose of the Commission's ROE analysis is to determine a level of return sufficient to satisfy *Hope* and *Bluefield*. Under that precedent, we are tasked with ensuring that the base ROE, among other things, enables the utility to attract investment. In contrast, ROE incentive adders are intended to encourage transmission investment above the level produced by a base ROE due to the circumstances of a certain project or projects. Although section 219 of the FPA gives us authority to provide incentives above the base ROE, nothing in section 219 relieves us from first setting the base ROE at a place that meets *Hope* and *Bluefield*. As

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the midpoint of the upper half of the range. *See Transcon. Gas Pipe Line Corp*., Opinion No. 414-A, 84 FERC ¶ 61,084, at 61,427-3 (1998) ("the Commission has determined that the parties to a rate proceeding may present evidence they believe is warranted to support any ROE that is within the DCF-derived zone of reasonableness. . . .").

[307] *See, e.g.*, Opinion No. 445, 92 FERC at 61,266; *Consumers Energy Co.*, Opinion No. 429, 85 FERC at 61,363-64. We note that the Commission has also in the past established the base ROE at the top of the zone of reasonableness, *see, e.g.*, Opinion No. 524, 142 FERC ¶ 61,197 at P 4; however, the record in this proceeding does not support, nor do the NETOs argue in favor of, setting the base ROE at the top of the zone.

shown above, our decision regarding the placement of the ROE in the zone meets that precedent.

D. Establishment of Paper Hearing

154. Because we change our approach to setting ROEs in this order, to now and henceforth use the two-step DCF methodology in determining the ROE for public utilities, and the parties did not address that methodology on the record, we will reopen the record for the limited purpose of allowing the participants to this proceeding an opportunity to present written evidence concerning one issue unique to the application of the two-step DCF methodology to the facts of this proceeding. Specifically, because the one-step DCF methodology does not include a long-term growth projection, the participants have not had an opportunity to present evidence concerning the appropriate long-term growth projection to be used for public utilities under the two-step DCF methodology. Therefore, we establish a paper hearing proceeding to provide the participants, including Trial Staff, the opportunity to submit additional evidence and argument concerning the limited issue of the appropriate long-term growth projection to be used in the two-step DCF methodology.

155. However, use of the two-step DCF methodology does not affect the other issues litigated by the parties at the hearing. The two-step DCF methodology uses the same IBES short-term growth projections as the one-step DCF methodology, and the same raw data is used to calculate dividend yields under both methodologies. In addition, the issues of using a national vs. a regional proxy group, application of credit screens, exclusion of companies with dividend cuts or merger activity within the six-month study period, exclusion of outliers, and the placement of the base ROE within the zone of reasonableness are unaffected by what DCF methodology is used. We conclude that the Commission need not establish hearing procedures on the placement of the base ROE within the zone of reasonableness because the hearing already held before the Presiding Judge provided the parties a full opportunity to present evidence on all these issues, including a full opportunity to contest all the evidence we have relied upon in our findings concerning placement in the zone.[308] Accordingly, in order to resolve this proceeding as expeditiously and efficiently as possible consistent with due process, we will not reopen the record for the purpose of allowing any additional evidence to be presented on those issues. For the same reasons, we will not allow any further updating of the financial data beyond the October 2012 through March 2013 period approved in this order.

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[308] *See, e.g.*, Ex. NET-300 at 7-8, 44-45, 45-72, 81-82; Ex. NET-400 at 26-27; Ex. S-12; Ex. NET-500 at 12.

156. Initial briefs are due within 45 days of the issuance of this order, and reply briefs are due within 30 days after the submission of initial briefs. The page limit for each brief will be 25 pages;[309] however, we impose no page limit on attached expert testimony.

VII. Elimination of the Treasury Bond Update

157. The Commission's policy in public utility ROE cases has been to establish a just and reasonable ROE, within a zone of reasonableness, based upon test-period evidence. However, because capital market conditions can change between the date the utility files its case-in-chief and the date the Commission issues a final decision, the Commission updates the ROE within the zone of reasonableness at the time of the final decision to reflect those capital market changes.[310] The Commission's long-standing practice has been to base this post-hearing adjustment on the change in U.S. Treasury bond yields during the same time period.[311] We now change that practice.

158. The premise underlying the use of U.S. Treasury bonds for the post-hearing ROE adjustment is that changes in ROE over time track changes in U.S. Treasury bond yields. However, while U.S. Treasury bond yields are an important indicator of capital market conditions and therefore inform our determination of an appropriate base ROE, the capital market conditions since the 2008 market collapse and the record in this proceeding have shown that there is not a direct correlation between changes in U.S. Treasury bond yields and changes in ROE. Therefore, the premise underlying the Commission's use of U.S. Treasury bond yields for post-hearing ROE adjustments is not always accurate. In *Southern California Edison Company*, a 2008 case in which the post-hearing adjustment was at issue, expert testimony indicated that, as U.S. Treasury bond yields decreased DCF results instead went up, indicating an inverse relationship between

[309] We take this opportunity to remind the participants of the requirements contained in Rule 2003 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2003 (2013).

[310] *E.g.*, *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 100 (citing *City of Vernon, Cal.*, Opinion No. 479, 111 FERC ¶ 61,092 (2005); *Jersey Cent. Power & Light Co.*, Opinion No. 408, 77 FERC ¶ 61,001).

[311] *E.g.*, *Ill. Power Co.*, 15 FERC ¶ 61,050, at 61,095 (1981); *see also Union Elec. Co. v. FERC*, 890 F.2d 1193 (D.C. Cir. 1989) (affirming the Commission's use of U.S. Treasury bond yields to make post-hearing adjustments within the range of reasonableness).

U.S. Treasury bond yields and utility ROE.[312] The record in this proceeding also shows an inverse relationship, but with rates moving in opposite directions: U.S. Treasury bond yields have increased while DCF results for the NETOs have gone down.[313]

159. The record in this proceeding also casts doubt on the magnitude, not just the direction, of the relationship between U.S. Treasury bond yields and utility ROE. The Commission's practice traditionally has been to adjust the ROE using a 1:1 correspondence between the ROE and the change in U.S. Treasury bond yields—i.e., for every basis point change in the U.S. Treasury bond yield the Commission would adjust the ROE by one basis point. However, the record in this proceeding indicates that the 1:1 correspondence may not be accurate under current financial conditions, and that a significantly different ratio might be more appropriate—i.e., for every basis point the U.S. Treasury bond yields change, the Commission should adjust the ROE by a fraction of that amount.[314] Thus, the record evidence indicates that, currently, adjusting ROEs based on changes in U.S. Treasury bond yields may not produce a rational result, as both the magnitude and direction of the correlation may be inaccurate.

160. Upon consideration of the record evidence in this proceeding, and in light of the economic conditions since the 2008 market collapse more generally, U.S. Treasury bond yields do not provide a reliable and consistent metric for tracking changes in ROE after the close of the record in a case. Accordingly, we conclude that, rather than updating ROEs by taking official notice of post-hearing changes in U. S. Treasury bond yields, a more reasonable approach is to allow the participants in a rate case to present the most recent financial data available at the time of the hearing, including post-test period financial data then available. This approach will ensure that all participants have an opportunity to present evidence and argument concerning the financial data used to determine the public utility's ROE, while allowing the ROE to be based on the most recent financial data available at the time of the hearing consistent with the due process

[312] *S. Cal. Edison Co. v. FERC*, 717 F.3d at 187-88 (remanding for the Commission to consider evidence that the U.S. Treasury bond yields and corporate bond yields might be inversely related and, therefore, not rationally related).

[313] *Compare* Initial Decision, 144 FERC ¶ 63,012 at P 551 n.49 (stating that the NETOs' DCF analyses in this proceeding indicate a lower cost of equity estimate for the prospective period than the refund period); *with* Ex. EMC-1 at 6-7 (indicating that the average 10-year U.S. Treasury bond yield in Oct. 2012 was between 1.7 and 1.8 percent) and Tr. 560 (indicating that the average 10-year U.S. Treasury bond yield for the period from Oct. 2012 to Mar. 2013 increased slightly to 1.83 percent).

[314] *See generally* May 8, 2013 Transcript at 562-570, 597, 605-606.

rights of the participants. This approach is also consistent with our longstanding practice in natural gas and oil pipeline rate cases.[315] We will, therefore, no longer use changes in U.S. Treasury bond yields to conduct post-hearing adjustments in public utility ROE proceedings.

VIII. Impact of the DCF Methodology Change on Existing ROE Transmission Incentive Adders

161. As noted above, the Commission is changing its approach to require that cost of equity estimates be calculated using the two-step DCF methodology. In general, the two-step DCF methodology will produce a narrower zone of reasonableness than use of the one-step DCF methodology for two reasons: (1) long-term growth rates are more stable than short-term growth rates, and (2) the two-step DCF methodology does not calculate a high-end estimate and low-end estimate for each proxy group company's cost of equity, but rather calculates one estimate for each company.

162. In section 219(a) of the FPA, Congress directed the Commission to establish incentive-based rate treatments to foster investment in transmission facilities. The Commission implemented FPA section 219 in Order No. 679.[316]

163. In order to satisfy the requirement of FPA section 219(d) that any rate incentives be consistent with FPA section 205, the Commission in Order No. 679 stated, "an incentive rate of return sought by an applicant must be within a range of reasonable returns and the rate proposal as a whole must be within the zone of reasonableness before it will be approved."[317]

164. Based on the Commission's policy that the total ROE including any incentive ROE is limited to the zone of reasonableness, the Commission has found in the past that an incentive ROE may not be implemented in full by the utility if the total ROE exceeds the zone of reasonableness. In *Pacific Gas and Electric Company*, for example, the Commission stated that a 200 point basis adder previously granted to Pacific Gas & Electric Company would be limited to within the range of the zone of reasonableness

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[315] Opinion No. 510, 134 FERC ¶ 61,129 at PP 242-246, *order on reh'g*, 142 FERC ¶ 61,198 at PP 205-206.

[316] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[317] *Id*. P 2; *see also id.* P 93.

determined at hearing.[318] The Commission has consistently applied this policy in other recent incentive ROE cases.[319] Nothing in this order changes this Commission policy.

165. Accordingly, when a public utility's ROE is changed, either under section 205 or section 206 of the FPA, that utility's total ROE, inclusive of transmission incentive ROE adders, should not exceed the top of the zone of reasonableness produced by the two-step DCF methodology.

IX. Conclusion

166. On balance, we find that our actions in this order, including the shift to the use of the two-step DCF methodology, the placement of the NETOs' base ROE at the midpoint of the upper half of the zone of reasonableness, and the elimination of the post-hearing adjustment based on U.S. Treasury bonds, taken together produce a base ROE that reasonably balances investor and consumer interests consistent with *Hope* and *Bluefield* and allow just and reasonable rates for consumers and transmission owners.[320]

The Commission orders:

(A) The Initial Decision is hereby affirmed in part and reversed in part, as described in the body of this order.

[318] *Pac. Gas & Elec. Co.*, 141 FERC ¶ 61,168, at P 26 (2012) ("While we continue to grant the 200 basis-point adder for the Path 15 upgrade, we remind PG&E that any ROE adder is limited to within the range of reasonableness of the ROE . . . ").

[319] *See Trans Bay Cable, LLC*, 145 FERC ¶ 61,151, at PP 18-19 (2013); *Atl. Path 15, LLC*, 135 FERC ¶ 61,037 (2011).

[320] *See, e.g.*, *Hope*, 320 U.S. at 603.

(B) A paper hearing is hereby established, as discussed in the body of this order. Initial briefs are due within 45 days of the issuance of this order, and reply briefs are due within 30 days after the submission of initial briefs. Briefs are limited to 25 pages.

By the Commission. Commissioner Norris is dissenting in part with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix

EL11-66-000: MARTHA COAKLEY, ET.AL. V. BANGOR HYDRO-ELECTRIC CO., ET.AL.
FERC DCF Analysis: Natural Gas Model Using Data for the Six-Month Period Beginning October 2012 and Ending March 2013
Data Screens: Value Line data & I/B/E/S growth; Pays common dividend; No merger activity in past 6 months
Risk Screens: Credit Ratings (S&P: A to BBB-, Moody's A1 to Baa3)

Ticker	Company Name	6 Mos. Avg Div. Yield	Growth Rate ("g") I/B/E/S	GDP	Composite	Adj. Div. Yield	DCF Result	Reason for Removal
ALE	ALLETE, Inc.	4.37%	6.00%	4.39%	5.46%	4.49%	9.95%	
LNT	Alliant Energy Corp.	4.14%	5.87%	4.39%	5.38%	4.25%	9.63%	
AEE	Ameren Corp.	4.99%	-1.80%	4.39%	0.26%	4.99%	--	Low-end Outlier
AEP	American Electric Power Co., Inc.	4.22%	3.60%	4.39%	3.86%	4.31%	8.17%	
AVA	Avista Corp.	4.84%	4.00%	4.39%	4.13%	4.94%	9.07%	
BKH	Black Hills Corp.	4.00%	6.00%	4.39%	5.46%	4.11%	9.57%	
CNP	CenterPoint Energy, Inc.	3.99%	5.00%	4.39%	4.80%	4.09%	8.89%	
CNL	Cleco Corp.	3.20%	8.00%	4.39%	6.80%	3.30%	10.10%	
CMS	CMS Energy Corp.	4.09%	5.90%	4.39%	5.40%	4.20%	9.60%	
ED	Consolidated Edison, Inc.	4.26%	2.00%	4.39%	2.80%	4.32%	7.12%	
D	Dominion Resources, Inc.	4.22%	7.27%	4.39%	6.31%	4.36%	10.67%	
DTE	DTE Energy Co.	3.97%	4.42%	4.39%	4.41%	4.05%	8.46%	
DUK	Duke Energy Corp.	4.62%	4.20%	4.39%	4.26%	4.72%	8.98%	
EIX	Edison International	2.91%	-1.90%	4.39%	0.20%	2.91%	--	Low-end Outlier
EE	El Paso Electric Co.	3.04%	3.70%	4.39%	3.93%	3.10%	7.03%	
EDE	Empire District Electric Co.	4.73%	3.00%	4.39%	3.46%	4.81%	8.28%	
FE	FirstEnergy Corp.	5.26%	4.60%	4.39%	4.53%	5.38%	9.91%	
GXP	Great Plains Energy Inc.	4.04%	6.55%	4.39%	5.83%	4.16%	9.99%	
HE	Hawaiian Electric Industries, Inc.	4.75%	3.30%	4.39%	3.66%	4.83%	8.50%	
IDA	IDACORP, Inc.	3.39%	4.00%	4.39%	4.13%	3.46%	7.59%	
TEG	Integrys Energy Group, Inc.	5.01%	5.67%	4.39%	5.24%	5.15%	10.39%	
NEE	NextEra Energy, Inc.	3.72%	6.20%	4.39%	5.60%	3.82%	9.42%	
NU	Northeast Utilities	3.67%	8.04%	4.39%	6.82%	3.79%	10.62%	
NWE	NorthWestern Corp.	4.18%	5.00%	4.39%	4.80%	4.28%	9.08%	

OGE	OGE Energy Corp.	2.87%	4.55%	4.39%	4.50%	2.93%	7.43%	
OTTR	Otter Tail Corp.	4.60%	5.00%	4.39%	4.80%	4.71%	9.51%	
POM	Pepco Holdings, Inc.	5.46%	3.63%	4.39%	3.88%	5.57%	9.45%	
PCG	PG&E Corp.	4.34%	3.10%	4.39%	3.53%	4.41%	7.94%	
PNW	Pinnacle West Capital Corp.	4.10%	7.30%	4.39%	6.33%	4.23%	10.56%	
POR	Portland General Electric Co.	3.86%	5.58%	4.39%	5.18%	3.96%	9.14%	
PPL	PPL Corp.	4.96%	2.70%	4.39%	3.26%	5.04%	8.31%	
PEG	Public Service Enterprise Group Inc.	4.59%	-0.68%	4.39%	1.01%	4.61%	--	Low-end Outlier
SCG	SCANA Corp.	4.26%	4.43%	4.39%	4.42%	4.36%	8.77%	
SRE	Sempra Energy	3.50%	5.65%	4.39%	5.23%	3.59%	8.82%	
SO	Southern Company	4.40%	4.80%	4.39%	4.66%	4.50%	9.16%	
TE	TECO Energy, Inc.	5.09%	2.90%	4.39%	3.40%	5.18%	8.58%	
UIL	UIL Holdings Corp.	4.72%	8.10%	4.39%	6.86%	4.88%	11.74%	
VVC	Vectren Corp.	4.64%	5.00%	4.39%	4.80%	4.75%	9.55%	
WR	Westar Energy, Inc.	4.42%	6.50%	4.39%	5.80%	4.55%	10.34%	
WEC	Wisconsin Energy Corp.	3.51%	5.37%	4.39%	5.04%	3.60%	8.64%	
XEL	Xcel Energy, Inc.	3.90%	5.12%	4.39%	4.88%	3.99%	8.87%	
	Zone of Reasonableness					**7.03%**	**---**	**11.74%**
					Midpoint:		**9.39%**	
					75th Percentile:		**10.57%**	

Long-term U.S. Gross Domestic Product (GDP) Growth Estimates For the Fourth Quarter of 2012

Source	Year Beginning	Nominal GDP ($Billion)	Year Ending	Nominal GDP ($Billion)	Annual GDP Growth (%)
IHS Global Insight [1]	2017	$ 19,369	2043	$ 57,599	4.28%
EIA [2]	2017	$ 19,421	2040	$ 51,037	4.29%
SSA [3]	2017	$ 20,392	2067	$ 191,986	4.59%
Average:					**4.39%**

Notes

[1] IHS Global Insight: Long-Term Macro Forecast - Baseline (U.S. Economy 30-Year Focus, First Quarter (March 1, 2013), Table Summary 1(a), http://www.globalinsight.com/

2 Report: Annual Energy Outlook 2013 (Release date: April 2013): Table 20. Macroeconomic Indicators. Nominal GDP=(Real GDP)*(GDP Chain-Type Price index). http://www.eia.gov/forecasts/aeo/data.cfm?filter=macroeconomic#macroeconomic (Table 20)

3 Social Security Administration: The 2012 OASDI Trustees Report (April 25, 2012), Table VI.F4.-- OASDI and HI Annual and Summarized Income, Cost, and Balance as a Percentage of GDP, Calendar Years 2012-90, Intermediate Assumptions. Note: (GDP2067)=(GDP2065)*((GDP2070/GDP2065)^(2/5)) http://www.ssa.gov/oact/tr/2012/VI_F2_OASDHI_GDP.html#181864

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Martha Coakley, Massachusetts Attorney General; Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Company; Associated Industries of Massachusetts; The Energy Consortium; Power Options, Inc.; and the Industrial Energy Consumer Group

Docket No. EL11-66-001

v.

Bangor Hydro-Electric Co.; Central Maine Power Co.; New England Power Co. d/b/a National Grid; New Hampshire Transmission LLC d/b/a NextEra; NSTAR Electric and Gas Corp.; Northeast Utilities Service Co.; The United Illuminating Co.; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Co.; Vermont Transco, LLC

(Issued June 19, 2014)

NORRIS, Commissioner, *dissenting in part*

We act today to address the backlog of complaint cases filed before the Commission arguing that returns on equity (ROE) for a number of public utilities are too high, and thus the rates derived from such ROEs are no longer just and reasonable. These cases have sat for too long, and I thank Chairman LaFleur for her leadership in working to promptly address the complaints under her watch.

Today's order addresses the complaint filed against the New England transmission owners' ROE. It also serves to announce the Commission's new approach for making determinations on ROE complaints as well as any ROEs proposed under Federal Power Act (FPA) section 205. Based on the record in this proceeding, today's order finds that an upward adjustment from long-standing Commission policy to set the ROE at the

central tendency of the zone of reasonableness is warranted. The order then adjusts the ROE to the midpoint of the upper half of the zone.

While I agree that an upward adjustment from the central tendency is warranted in this case, the decision to grant New England transmission owners an ROE at the midpoint of the upper half of the zone of reasonableness is unjustified, lacks reasoning to support it, and sets troubling precedent. I am concerned that this determination subjects consumers to unjust and unreasonable rates in this proceeding and potentially in future ROE proceedings.

Given unusual capital market conditions that all parties to this proceeding acknowledge, particularly the historically low bond yields, I support the Commission's decision to look beyond the results of our traditional discounted cash flow methodology to inform the placement of the ROE within the zone of reasonableness. The record in this proceeding shows that a straight-forward application of the discounted cash flow methodology would result in a dramatic decrease in ROE and result in a level below that generally set by state commissions for electric distribution assets. This level risks failing to meet our *Hope* and *Bluefield*[1] requirements that ROEs be set so as to enable transmission owners to attract capital for new investment in transmission. I strongly believe that as a nation we still need more investment in transmission to promote competitive markets, reduce congestion, enhance reliability, and enable access to renewable resources. For these reasons, I conclude in this proceeding that an upward adjustment from the central tendency is warranted.

However, I cannot support the upward adjustment from the central tendency approved in today's order. With little justification or support, today's order agrees to the New England transmission owners' request to set their ROE at the midpoint of the upper half of the zone of reasonableness. Today's order has not met the burden to show that a 118 basis point upward adjustment from the central tendency to the midpoint of the upper half of the zone is a necessary and appropriate measure in this proceeding to meet our *Hope* and *Bluefield* requirements, or our FPA section 205 and 206 mandate to ensure that rates are just and reasonable.

[1] *FPC v. Hope Natural Gas Co.*, 320 U.S. 581 (1944) (*Hope);* and *Bluefield Water Works & Improvement Co. V. Pub. Serv.* Comm'n, 262 U.S. 679 (1923) (*Bluefield).*

Indeed, today's order cites only two cases from over a decade ago where the Commission approved an ROE adjustment to the midpoint of the upper half.[2] These cases do not provide relevant precedent, because they involved adjusting the ROE above the central tendency based on the risk profile of a utility that differed from the proxy group studied, a determination that was not made in the current proceeding.[3]

Looking beyond today's order, my broader concern is that the precedent established through this adjustment could become the new norm that would potentially ratchet up and lock in substantially higher ROEs in future cases. I am further troubled by today's order in light of recent Commission decisions on Order No. 1000 compliance filings that have served to protect incumbent transmission owners from competition in the development of new transmission. Simply put, not only will incumbent transmission owners be more insulated from competition, they will also be the primary beneficiaries of the new precedent established in this proceeding that could provide for substantially higher ROEs.

Given the potential significance of today's decision, I would have set the appropriate level of the upward adjustment from the central tendency for paper hearing. The New England transmission owners convincingly argue in the record that an upward adjustment is warranted, but then with limited justification argue that the correct adjustment is the midpoint of the upper half of the zone of reasonableness. Meanwhile, consumer representatives and Commission trial staff at the hearing before the judge argue that no deviation from the central tendency is warranted, consistent with existing Commission policy. Parties were not on notice that the Commission would now deviate from its long-standing precedent that relies on the central tendency. A paper hearing would have efficiently afforded all affected parties the opportunity to make their case in the record as to the appropriate level of the upward adjustment from the central tendency. Regrettably, today's order tilts the balance in favor of the New England transmission owners without further recourse and fails to adequately give a voice to consumer interests.

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[2] *Consumers Energy Co.*, 85 FERC ¶ 61,100 (1998); and *S. Cal. Edison Co.*, 88 FERC ¶ 61,254 (1999).

[3] Notably, moving from the central tendency to the midpoint of the upper half of the zone of reasonableness first in *Consumers Energy* and then in *S. Cal. Edison* resulted in an 18 basis point and a 58 basis point upward adjustment, respectively. In contrast, the adjustment in this case results in a much larger 118 basis point increase.

Finally, I note that in future ROE cases, if parties wish to argue for an upward adjustment, they should make their case for the appropriate level of the adjustment. The Commission should then determine whether or not the record evidence in each individual proceeding warrants an adjustment, and if so, to what level.

For these reasons, I respectfully dissent in part.

_____

John R. Norris, Commissioner

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. 2016 Electric Rate Increase Application

Case No. PU-16-666

FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

June 16, 2017

Appearances

Commissioners Randy Christmann, Julie Fedorchak, and Brian Kroshus.

Karl Liepitz, Assistant General Counsel, P.O. Box 5650, 1200 West Century Avenue, Bismarck, ND 58506-5650 and Paul Sanderson, Evenson Sanderson, PC, 103 S. 3rd St., Suite 5, Bismarck, ND 58501, appearing on behalf of Montana-Dakota Utilities Co.

John M. Schuh, Legal Counsel, Public Service Commission, State Capitol, 600 E. Boulevard Avenue, Bismarck, ND 58505, and Mitch Armstrong, Special Assistant Attorney General, 122 E. Broadway Ave., Bismarck, ND 58501, appearing on behalf of Public Service Commission Advocacy Staff.

John B. Coffman, John B. Coffman, LLC, 871 Tuxedo Blvd., St. Louis, MO 63119-2044, and David Tschider, Tschider & Smith, 418 E. Rosser Ave., Ste. 200, Bismarck, ND 58501, appearing on behalf of AARP.

Illona Jeffcoat-Sacco, General Counsel, Public Service Commission, State Capitol, 600 E. Boulevard Avenue, Bismarck, North Dakota 58505, appearing on behalf of the Public Service Commission Advisory Staff.

Patrick Ward, Administrative Law Judge, Office of Administrative Hearings, 2911 North 14th Street, Suite 303, Bismarck, North Dakota 58503 as Procedural Hearing Officer.

Preliminary Statement

On October 14, 2016, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. (MDU) filed an application and notice to increase its North Dakota electric service rates based on a 2017 test year (Application). The Application proposed an increase in electric rates to provide additional annual revenue of $13,381,639, or an overall increase in projected annual retail revenues of 6.6 percent, at current rates as of

the filing date. Filed with the Application were revised tariffs, direct testimony, exhibits and supporting statements.

MDU concurrently submitted an Application and Notice for an interim increase in electric rates in the annual amount of $13,027,771 to be effective within 60 days from filing.

On November 2, 2016, the Public Service Commission (Commission) suspended MDU's general rate increase application by motion.

On November 30, 2016, the Commission issued an Order approving an interim rate increase of $11,695,592 to become effective for service rendered on or after December 13, 2016.

On November 30, 2016, the Commission issued a Notice of Intervention Deadline, Notice of Public Input Sessions and Notice of Hearing, scheduling public input sessions for January 23, 2017, and January 25, 2017, and scheduling the formal hearing for April 10, 2017. The Notice of Hearing encouraged anyone interested in becoming a party to the proceeding to file a petition to intervene by January 27, 2017. The public input sessions were held as scheduled. The notice identified the following issues to be considered in this proceeding:

1. What is the value of MDU's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is MDU's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?

3. What is a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota?

5. Are MDU's proposed rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

On January 27, 2017, a Petition to Intervene was filed by AARP.

On February 3, 2017, the Administrative Law Judge granted the petition to intervene of AARP.

On April 7, 2017, MDU, Commission Advocacy Staff (Advocacy Staff), and AARP entered into a Settlement Agreement that would resolve all the issues in this proceeding. A copy of the Settlement Agreement is attached. The Settlement Agreement provides for implementation of a net increase in electric rates for retail customers in North Dakota to yield a net annual revenue increase of $7.5 million, or approximately 3.7%, effective upon a final order in this proceeding. This revenue increase is based upon a return on equity of 9.65 percent and a return on rate base of 7.364 percent for retail rates and all riders except for the Generation Rider, which will continue at least through December 31, 2019 and will be established based on a return on equity of 9.45 percent. The parties agreed that the true-up adjustments applicable under the Generation, Transmission, and Renewable Riders approved on an interim basis will be calculated based on a return on equity of 9.45 percent or an overall rate of return of 7.262 percent.

On April 10, 2017, a public hearing was held as scheduled in the Commission Hearing Room, State Capitol, 600 E. Boulevard Avenue, 12th Floor, Bismarck, North Dakota 58505.

On May 15, 2017, MDU filed a response to the Commission's April 19, 2017 letter to the parties regarding questions from the Commission's April 18, 2017 work session.

On June 1 and June 6, 2017, MDU filed responses to the Commission's June 1, 2017 letter to the parties regarding questions from the Commission's May 30, 2017 work session.

On June 8, 2017, Advocacy Staff filed a response to the Commission's June 1, 2017 letter to the parties regarding questions from the Commission's May 30, 2017 work session.

Having allowed all interested persons an opportunity to be heard, and having heard, reviewed and considered all testimony and evidence presented, the Commission makes the following:

Findings of Fact

1. MDU is a Division of MDU Resources Group, Inc., a Delaware corporation, duly authorized to provide electric service to retail customers in North Dakota.

2. The Settlement Agreement proposes a net increase in MDU's electric rates for retail customers in North Dakota to yield an annual revenue increase of $7.5 million effective upon a final order in this proceeding.

3. The Settlement Agreement proposes a return on equity of 9.65 percent effective upon a final order in this proceeding resulting in an overall rate of return of 7.364 percent based on the following capital structure:

	Ratio	Cost	Return
Long Term Debt	42.673%	5.245%	2.238%
Short Term Debt	4.840%	2.402%	0.116%
Preferred Stock	1.084%	4.579%	0.050%
Common Equity	51.403%	9.650%	4.960%
Total	100.000%		7.364%

4. The Settlement Agreement proposes the true-up adjustments applicable under the Generation, Transmission, and Renewable Riders approved on an interim basis in Case Nos. PU-15-703, PU-15-747 and PU-15-704 respectively will be calculated based on a return on equity of 9.45 percent or an overall rate of return of 7.262 percent based on the following capital structure:

	Ratio	Cost	Return
Long Term Debt	42.673%	5.245%	2.238%
Short Term Debt	4.840%	2.402%	0.116%
Preferred Stock	1.084%	4.579%	0.050%
Common Equity	51.403%	9.450%	4.858%
Total	100.000%		7.262%

True-up adjustment account balances remaining to be collected are:

Rider	True-Up (Over)/Under Collection Balance (as of December 31, 2016)
Transmission	$4,115,134
Renewable	(947,527)
Generation	1,834,599
Environmental	3,060,271

5. The Settlement Agreement proposes the Lewis and Clark RICE Units that are currently in the Company's Generation Rider will continue to be recovered through the Generation Rider and the Heskett III generator will be rolled in to base retail rates at this time. The overall return on rate base identified in Paragraph 4 is applicable under the Generation Rider until December 31, 2019. As of January 1, 2020, the Generation Rider recovering the Lewis and Clark RICE Units will be subject to the Company's overall authorized rate of return at that time. The Lewis and Clark RICE Units will be rolled into retail rate base in the Company's first rate case after December 31, 2019, at the then depreciated value. Should any generating units be placed into the generator rider other than the RICE units, those units will be subject to the overall authorized rate of return at that time.

6. The Settlement Agreement proposes existing wind facilities (Cedar Hills, Diamond Willow and Thunder Spirit) will be recovered through the Renewable Rider Rate 55.

7. The Settlement Agreement proposes the transmission assets currently recovered through the Transmission Rider will be moved to base retail rates and the Transmission Rider will continue to recover the types of regional transmission related expenses as submitted in the Application.

8. The Settlement Agreement proposes the Big Stone Air Quality Control Systems project and the Lewis & Clark Mercury and Air Toxics Standard project will be moved to base retail rates.

9. The Settlement Agreement proposes future decommissioning costs associated with costs incurred to decommission the Company's production facilities upon retirement must be initiated in this case at an annual amount of $500,000 with the annual amount collected recorded as a reduction to rate base.

10. The Settlement Agreement proposes the following allocation of revenues resulting in an increase by rate class as described below.

Customer Class	$	%
Residential Service	$4,114,698	5.2%
Small General Service	914,489	6.8%
General Service	2,295,884	2.2%
Municipal Lighting	2,751	0.2%
Municipal Pumping	164,815	5.5%
Outdoor Lighting Service	7,475	1.0%
Total North Dakota Electric	**$7,500,112**	**3.7%**

11. The Settlement Agreement proposes that MDU will provide an update to the Commission regarding each retail electric service contract reflecting a discounted rate by September 30, 2017.

12. The Settlement Agreement proposes MDU will file compliance tariffs reflecting the revenue requirement provisions and the revenue allocation denoted in Paragraph 9 of the Settlement Agreement, including the following revisions to tariffs upon issuance of an Order:

- MDU agrees to keep the current language on its Firm Service Economic Development Rate 34 that allows the Commission to review agreements under

this tariff.

- The "Time and Manner of the Filing" section on each of the rider schedules will be eliminated and MDU agrees to file its annual rider updates such that the Commission has a 90-day review period.
- MDU agrees not to institute Off-Peak Demand Charges in this case.
- The Basic Service Charges and Demand Charges as proposed by MDU, with the exception of the Residential Basic Service Charge described in Paragraph 13, are agreed to by the parties to the Settlement Agreement except that the Basic Service Charges for any of the non-residential tariff schedules shall not be less than currently authorized Basic Service Charge amounts.
- MDU agrees to revise its Employee Discount tariff language in Rate Schedule 100 to more clearly describe that the discounts on electric billings only apply to retirees that retired on or before December 31, 2009.
- The parties to the Settlement Agreement agree to all other tariff provision changes (notwithstanding specific charges) as proposed by MDU.

13. The Settlement Agreement proposes the Residential Daily Basic Service Charge will be increased to $0.46 per day.

14. The Settlement Agreement proposes MDU will develop a communication plan regarding consumer deposit information, in conjunction with Commission Staff, to be presented on the Company's website.

15. The Settlement Agreement proposes MDU will calculate its total Fuel and Purchased Power costs monthly versus having the charge as two parts with one being in base rates and the remaining part being the monthly adjustment that in the past has been shown on Rate 58. This eliminates the need to show a "Base Fuel and Purchased Power" rate on each rate schedule. MDU further agrees to eliminate the monthly tariff sheets that MDU has been filing and provide a table on MDU's website where the monthly fuel cost adjustments are easy for customers to find. MDU agrees to consult with Commission Staff for proper placement of the table on MDU's website.

16. The Settlement Agreement proposes MDU will utilize a stratified random sampling technique for selecting samples and the use of a ratio estimation technique to expand the sample data into class demand estimates for future class cost of service study purposes.

17. Since the net rate increase is less than the current interim increase collected from customers a refund will be due to customers. MDU will submit a refund plan within 30 days of this Order.

From the foregoing Findings of Fact, the Commission makes the following:

Conclusions of Law

1. The Commission has jurisdiction in these proceedings.

2. The rates proposed by the Settlement Agreement are necessary to provide a just and reasonable rate of return on MDU's property, used and useful, for the service and convenience of the public in North Dakota.

3. The rates proposed by Settlement Agreement are designed to result in a basis of charge to customers that are just and reasonable without discrimination.

From the foregoing Findings of Fact and Conclusions of Law, the Commission issues the:

Order

The Commission Orders:

1. The Settlement Agreement, a copy of which is attached to this Order and made a part of this Order, is approved.

2. MDU shall file, for Commission approval, compliance rate schedules consistent with this Order and the Settlement Agreement.

3. Within ninety (90) days of the Commission's approval of refund plan, MDU shall issue refunds to customers to reflect the difference in annual revenues collected under the interim increase and the effective date of the compliance rates approved by the Commission. The refunds shall be calculated in the manner provided in the Settlement Agreement.

PUBLIC SERVICE COMMISSION

Brian Kroshus **Commissioner**	**Randy Christmann** **Chairman**	**Julie Fedorchak** **Commissioner**

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

In the Matter of the Application of MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc., for Authority to Establish Increased Rates for Electric Service	)))))	**Case No. PU-16-666**

SETTLEMENT AGREEMENT

This Settlement Agreement is entered into by and between Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. ("Montana-Dakota" or "Company"), the Advocacy Staff of the North Dakota Public Service Commission ("Advocacy Staff"), and Intervenor AARP (collectively the "Settling Parties"). The Settling Parties agree this Settlement Agreement, if approved by the Public Service Commission ("Commission"), would resolve all outstanding expense, revenue, return, and rate design issues in this case between the Settling Parties in a manner consistent with the public interest and will result in just and reasonable rates for the Company's electric service in North Dakota.

PROCEDURAL HISTORY

1. On October 14, 2016, Montana-Dakota filed an application and notice to increase its North Dakota electric service rates based on a 2017 test year. The Application proposed an increase in electric rates to provide additional annual revenue of $13,381,639, or an overall increase in projected annual retail revenues of 6.6 percent, at current rates as of the filing date. Filed with the Application were revised tariffs, direct testimony, exhibits and supporting statements. The Company proposed the requested increase be divided among the customer classes as follows:

Customer Class	Percent Increase
Residential	9.4%
Small General	10.9%
Large General	4.0%
Municipal Lighting	1.1%
Municipal Pumping	9.7%
Outdoor Lighting	1.6%
Total	6.6%

2. Montana-Dakota concurrently submitted an Application and Notice for an interim increase in electric rates in the annual amount of $13,027,771 to be effective within 60 days from filing.

3. The Commission suspended Montana-Dakota's general rate increase application by motion on November 2, 2016.

4. On November 30, 2016, the Commission issued an Order approving an interim rate increase of $11,695,592 to become effective for service rendered on or after December 13, 2016.

5. On November 30, 2016, the Commission issued a Notice of Intervention Deadline, Notice of Public Input Sessions and Notice of Hearing, scheduling public input sessions for January 23, 2017, and January 25, 2017, and scheduling the formal hearing for April 10, 2017. The Notice of Hearing also encouraged anyone interested in becoming a party to the proceeding to file a petition to intervene by January 27, 2017. The public input sessions were held as scheduled.

6. A Petition to Intervene was filed by the AARP. On February 3, 2017, the Administrative Law Judge granted the petition to intervene of AARP.

7. Settlement discussions were held between the Settling Parties pursuant to the Commission's Settlement Guidelines dated January 4, 1995. As a result of multiple

settlement discussions, the Settling Parties reached this Settlement Agreement.

8. The Settlement Agreement is supported by the administrative record. Accordingly, the Settling Parties jointly recommend the Commission issue an Order approving this Settlement Agreement in its entirety, without conditions or modifications.

TERMS OF SETTLEMENT AGREEMENT

1. Overall Revenue Increase. The Parties agree to, and recommend the Commission approve, a net increase in Montana-Dakota's electric rates for retail customers in North Dakota to yield an annual revenue increase of $7.5 million effective upon a final order in this proceeding. This represents an overall increase in rates of 3.7%. The change between the Company's Application and the amount agreed to herein is attributable to the following adjustments:

	(Million $'s)
Company's Application as Filed	$13.4
Update for 2016 Actual Results	(1.1)
ROE at 9.65%	(2.0)
Decommissioning	(1.4)
Incentive Plan Costs	(0.5)
Other Capital and O&M	(0.9)
Net Revenue Increase	$7.5

2. Return on Equity. The Parties agree to, and recommend the Commission approve, a return on equity of 9.65 percent effective upon a final order in this proceeding resulting in an overall rate of return of 7.364 percent based on the following capital structure:

	Ratio	Cost	Return
Long Term Debt	42.673%	5.245%	2.238%
Short Term Debt	4.840%	2.402%	0.116%
Preferred Stock	1.084%	4.579%	0.050%
Common Equity	51.403%	9.650%	4.960%
Total	100.000%		7.364%

3. Generation, Transmission, and Renewable Rider True-Up Adjustments. The Settling Parties agree that the true-up adjustments applicable under the Generation, Transmission, and Renewable Riders approved on an interim basis in Case Nos. PU-15-703, PU-15-747 and PU-15-704 respectively will be calculated based on a return on equity of 9.45 percent or an overall rate of return of 7.262 percent based on the following capital structure.

	Ratio	Cost	Return
Long Term Debt	42.673%	5.245%	2.238%
Short Term Debt	4.840%	2.402%	0.116%
Preferred Stock	1.084%	4.579%	0.050%
Common Equity	51.403%	9.450%	4.858%
Total	100.000%		7.262%

4. Generation Rider. The Settling Parties agree that the Lewis and Clark RICE Units that are currently in the Company's generation rider will continue to be recovered through the Generation Rider and the Heskett III generator will be rolled in to base retail rates at this time. The overall return on rate base identified in Paragraph 3 shall be applicable under the Generation Rider until December 31, 2019. As of January 1, 2020, the Generation Rider recovering the Lewis and Clark RICE Units will be subject to the Company's overall return on rate base in effect on that date. The Lewis and Clark RICE Units will be rolled into retail rate base in the Company's first rate case after December 31, 2019, at the then depreciated value.

5. Renewable Rider. The Settling Parties agree that all existing wind facilities (Cedar Hills, Diamond Willow and Thunder Spirit) will be recovered through the Renewable Rider Rate 55.

6. Transmission Rider. The Settling Parties agree that the transmission assets currently recovered through the Transmission Rider will be moved to base retail rates and the Transmission Rider will continue to recover the regional transmission related expenses as submitted in the Application.

7. Environmental Rider. The Settling Parties agree that the Big Stone Air Quality Control Systems project and the Lewis & Clark Mercury and Air Toxics Standard project will be moved to base retail rates.

8. Decommissioning Expense. The Settling Parties agree that future decommissioning costs associated with costs incurred to decommission the Company's production facilities upon retirement shall be initiated in this case at an annual amount of $500,000 with the annual amount collected recorded as a reduction to rate base.

9. Revenue Allocation. The Settling Parties agree to the following allocation of revenues resulting in an increase by rate class as described below.

Customer Class	$	%
Residential Service	$4,114,698	5.2%
Small General Service	914,489	6.8%
General Service	2,295,884	2.2%
Municipal Lighting	2,751	0.2%
Municipal Pumping	164,815	5.5%
Outdoor Lighting Service	7,475	1.0%
Total North Dakota Electric	**$7,500,112**	**3.7%**

A residential customer using 980 Kwh with a $0.46 daily basic service charge will see an increase of $4.50 per month on average.

10. Contract Discount Rates. The Company agrees that it will provide an update to the Commission regarding each contract reflecting a discounted rate by September 30, 2017.

11. Compliance Tariffs. The Company shall file compliance tariffs reflecting the revenue requirement provisions and the revenue allocation denoted in Paragraph 9 of this Settlement Agreement, including the following revisions to tariffs upon issuance of an Order:

- The Company agrees to keep the current language on its Firm Service Economic Development Rate 34 that allows the Commission to review agreements under this tariff.

- The "Time and Manner of the Filing" section on each of the rider schedules shall be eliminated and the Company agrees to file its annual rider updates such that the Commission has a 90-day review period.

- The Company agrees not to institute Off-Peak Demand Charges in this case.

- The Basic Service Charges and Demand Charges as proposed by the Company, with the exception of the Residential Basic Service Charge described in Paragraph 12, are agreed to by the Settling Parties except that the Basic Service Charges for any of the non-residential tariff schedules shall not be less than currently authorized Basic Service Charge amounts.

- The Company agrees to revise its Employee Discount tariff

language in Rate Schedule 100 to more clearly describe that the discounts on electric billings only apply to retirees that retired on or before December 31, 2009.

- The Settling Parties agree to all other tariff provision changes (notwithstanding specific charges) as proposed by the Company.

12. Residential Basic Service Charge. The Settling Parties agree the Residential Daily Basic Service Charge will be increased to $0.46 per day.

13. Consumer Deposit Information. The Company agrees to develop a communication plan regarding consumer deposit information, in conjunction with Commission Staff, to be presented on the Company's website.

14. Monthly Fuel Cost Adjustments. The Company agrees to calculate its total Fuel and Purchased Power costs monthly versus having the charge as two parts with one being in base rates and the remaining part being the monthly adjustment that in the past has been shown on Rate 58. This eliminates the need to show a "Base Fuel and Purchased Power" rate on each rate schedule. The Company further agrees to eliminate the monthly tariff sheets that the Company has been filing and provide a table on the Company's website where the monthly fuel cost adjustments are easy for customers to find. The Company agrees to consult with Commission Staff for proper placement of the table on the Company's website.

15. Load Research Studies. The Company agrees to utilize a stratified random sampling technique for selecting samples and the use of a ratio estimation technique to expand the sample data into class demand estimates for future class cost of service study purposes.

OTHER TERMS AND CONDITIONS

A. Basis of Settlement. It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission. This Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base for this or any future proceeding, nor any principle or precedent regarding rate design methodology.

B. Effect of the Settlement Negotiations. It is understood and agreed that all offers of settlement and discussions related to this Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement Agreement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or otherwise.

C. Interim Rate Refund. Since the base rate increase is less than the current interim increase collected from customers a refund will be due to customers. A refund plan will be submitted within 30 days of an entry of an Order in this case.

D. Applicability and Scope. This Settlement Agreement shall be binding on the Settling Parties, and their successors, assigns, agents, and representatives. Consistent with the Commission's settlement guidelines, this Settlement Agreement does not set policy or overturn precedent. This Settlement Agreement shall not in any respect constitute an agreement, admission or determination by any of the Settling Parties as to the merits of any specific allegation or contention made by the Settling Parties in this proceeding.

E. Effective Date. This Settlement Agreement shall be effective on the date

of the Commission Order approving the Settlement Agreement. The revised rates and tariffs agreed to by this Settlement Agreement shall be effective on the dates specified herein.

F. Modification. If the Commission's Order modifies or conditions approval of this Settlement Agreement, it shall be deemed terminated if any Settling Party files a letter with the Commission within three (3) business days of notice of such Order stating that a condition or modification to the Settlement Agreement is unacceptable to such party.

G. Suspension. On November 3, 2016, the Commission approved a motion to suspend the rates filed in this case. The Settling Parties agree to suspend the rate, classification, contract, practice, or rule beyond the time it would otherwise go into effect, and beyond six months, pursuant to N.D.C.C. § 49-05-06 while the Commission considers this matter. Further, if the Commission's order modifies or declines this Settlement, the Settling Parties agree to extend the suspension until such time as these proceedings are concluded.

CONCLUSION

The Settling Parties agree that adoption to the foregoing terms would resolve the issues in this proceeding. The terms of this Settlement Agreement are a result of negotiations between the Settling Parties, are in the public interest and will result in reasonable electric rates. For these reasons, the Settling Parties urge the Commission to approve the Settlement Agreement.

Dated this _____ day of April, 2017.

MONTANA-DAKOTA UTILITIES CO.

By:_____

Its:

Dated this 7th day of April, 2017.

NORTH DAKOTA PUBLIC SERVICE ADVOCACY STAFF

By: Whitehall D. Winston

Its: Attorney

Dated this _____ day of April, 2017.

AARP

By:_____

Its:

Dated this _____ day of April, 2017.

MONTANA-DAKOTA UTILITIES CO.

By:_____

Its:

Dated this _____ day of April, 2017.

NORTH DAKOTA PUBLIC SERVICE ADVOCACY STAFF

By:_____

Its:

Dated this 7th day of April, 2017.

AARP

By: John B Coffman

Its: Attorney

Dated this 7th day of April, 2017.

MONTANA-DAKOTA UTILITIES CO.

By: Garret Senger

Its: **Garret Senger**
EVP - Regulatory Affairs,
Customer Service, Gas Supply

Dated this _____ day of April, 2017.

NORTH DAKOTA PUBLIC SERVICE ADVOCACY STAFF

By: _____

Its:

Dated this _____ day of April, 2017.

AARP

By: _____

Its:

Liability Strategies Group

Global Markets

Deutsche Bank

February 2006

Corporate Dividend Policy

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Executive Summary

This paper discusses the theory and practice of corporate dividend and share repurchase policy drawing on the results of a recent survey.

Theoretical Considerations

- The table below lists the factors that are important in the choice between dividends and repurchases as a payout mechanism

Factor	Dominating Payout Form
Taxes	Depends
Conveying information	Depends on time horizon
Management bonding	Dividends
Shareholder rights	Depends on other factors
Investor preferences	Depends on preferences
Attracting monitors	Depends on other factors
Managing EPS	Repurchases
Changing capital structure	Depends on other factors
Residual policy	Depends on other factors

Survey Results

- Dividends continue to be the most important distribution mechanism. Of those firms who make some kind of distribution, 94% pay dividends, compared to 39% of the firms buying back shares
- When firms decide on the choice of distribution mechanism, they assign roughly equal weights to five factors:
  - The signal it sends to capital markets
  - The flexibility afforded by the distribution mechanism
  - The accounting implications
  - The tax efficiency of the alternatives
  - The attractiveness to different investors
- All of the above factors, except for the accounting implications, have strong theoretical support
- More than three quarters of the firms that pay dividends have a dividend payout ratio target. However, they are willing to deviate from that target when they set the level of the dividend. Firms set the dividend level so that they do not have to cut it; in addition it is important for companies to keep the dividend per share level stable or growing
- When firms globally are faced with insufficient cash flows to maintain the dividend, their first response is to cut the dividend, followed by cutting deferrable investment and borrowing up to the credit rating limit. The willingness of firms to cut the

dividend when cash flows are insufficient reduces the relative signalling power of dividends over share repurchases

- ➢ A notable exception is the North American region where cutting dividends is only considered after several other options have been exhausted

- Firms pay special dividends as a return of excess funds to shareholders
- Firms repurchase shares to return excess funds to shareholders, to increase leverage, and to take advantage of temporary mispricing of their shares. Increasing reported EPS and mitigating dilution from employee stock option schemes also affect repurchase decisions, although less strongly

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Introduction

This Paper

This paper provides an overview of current dividend and share repurchase policy theory together with a detailed analysis of the results of a recent corporate survey. The paper is divided into three sections:

- **This Introduction**
- **Theoretical Considerations**
- **Survey Results**

Global Survey of Corporate Financial Policies & Practices

The empirical evidence in this paper is drawn from a survey conducted during mid 2005 by Professor Henri Servaes of London Business School and Professor Peter Tufano of Harvard Business School. The project was originated and sponsored by Deutsche Bank AG with the Global Association of Risk Professionals (GARP) acting as secondary sponsor.

334 companies globally participated with responses distributed widely by geography and by industry. Further details of the sample can be found in the note "Survey Questions and Sample" which is available at www.dbbonds.com/lsg/reports.jsp.

Related Papers

In addition to this paper, five other papers drawing on the results of the survey include:

- CFO Views
- Corporate Capital Structure
- Corporate Debt Structure
- Corporate Liquidity
- Corporate Risk Management

All these papers are available at www.dbbonds.com/lsg/reports.jsp. The website also contains a streaming video of Professors Servaes and Tufano presenting an overview of the results at a Deutsche Bank hosted conference.

Notation and Typographical Conventions

The symbol $\bar{x}$ denotes the mean of a dataset, while $\tilde{x}$ denotes the median. N denotes the size of the dataset. All questions in the survey were optional and some questions were not asked directly, depending on the answers to previous questions. Therefore, the number of responses, N, to different questions varies and is shown for each question. Items in *italics* indicate that the term appeared as one of the answer options in the survey question. Items underlined indicate a reference to one of the other papers in this series. Due to rounding, the figures in some charts may not add up to the 100% or the total shown.

Unless otherwise stated, all data in this document is drawn from the results of The Global Survey of Corporate Financial Policies and Practices.

Theoretical Considerations

In this section we discuss the various arguments about dividend and share repurchase policy that have been advanced on theoretical grounds.

Irrelevance

To understand how payout policy may affect shareholder value, it is important to understand under the circumstances under which it does not matter.

As a starting point in the analysis, let's consider a very simplified scenario in which:

- There are no taxes
- Corporate executives have the same set of information as investors
- There are no transaction costs
- Investors and markets are rational
- The firm's level of investment is fixed
- There are no costs of recontracting or bankruptcy
- The interest of managers and shareholders are aligned

We call these the *perfect capital markets* assumptions. Under these conditions, consider the following example.

Example 1

A firm has assets that generate annual cash flows of €15 in perpetuity. To maintain its assets, the firm needs to invest €5 annually.

Equity investors in this all-equity firm demand a required rate of return of 10%, to compensate them for the inherent risk of the assets.

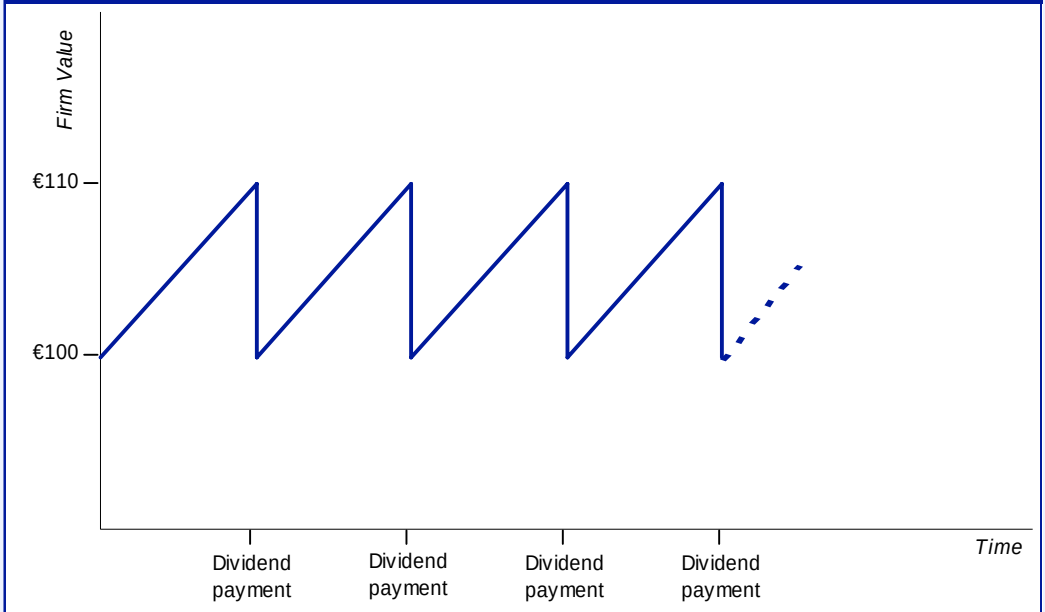
If the firm just pays out €10 per year as a dividend, after having reinvested €5, the value of the firm is €100 [=10/10%].[1] If the firm has 100 shares outstanding, each share is worth €1. This can be computed either as firm value/number of shares outstanding, or as dividend per share dividend by the required rate of return: €1.00 [=0.10/10%].

Let us examine the immediate effect on the value of the firm of the dividend payment. The valuation of €100 computed above assumes that the next dividend is paid exactly one year from now. As time goes by, firm value increases to reflect the fact that the next dividend payment comes closer. Right before the €10 dividend payment, firm value will be nearly €110 because investors are entitled to €10 almost immediately plus a perpetuity of €10 starting one year from now. After the dividend payment, the value of the firm declines back to €100.

Figure 1 illustrates of the value of the firm over time.

[1] See Appendix II for derivation of this formula.

Figure 1: Example Firm Value over Time with Dividend



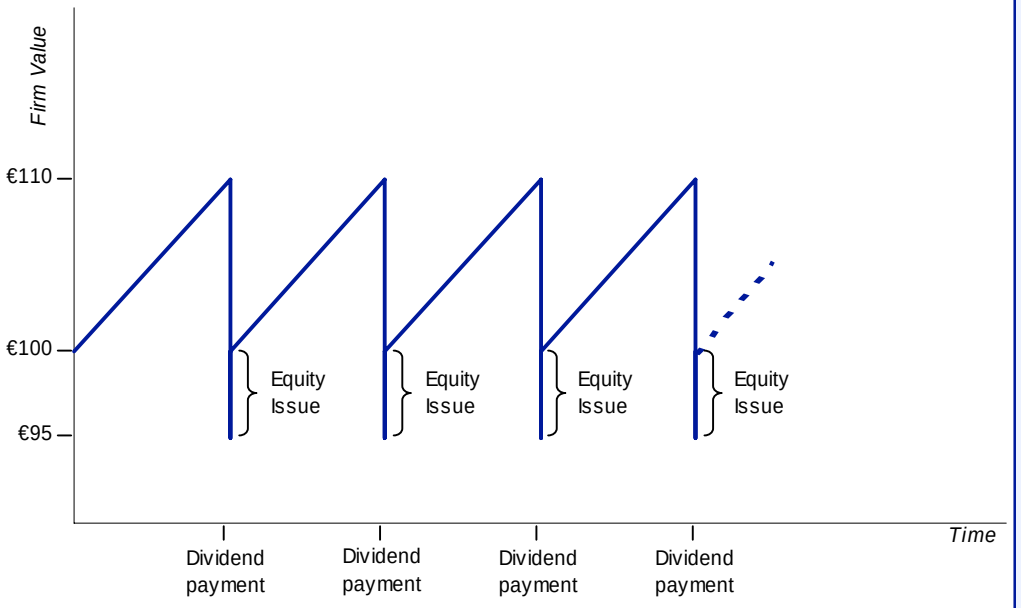
The value of a share will increase to €1.10 over time as the dividend payment date approaches and drop back to €1.00 once the dividend is paid.

Example 2

What happens to firm value if instead of paying out €10, the firm pays out the entire €15 and then immediately raises the additional funding through an equity issue?

Firm value will drop temporarily to €95 after the dividend payment, but immediately after the equity issue, it will increase again to €100 and the above scenario continues. The following graph illustrates this pattern.

Figure 2: Example Firm Value over Time with Dividend and Equity Issue



Thus, fundamentally, firm value will not be affected by the decision to pay out all earnings as a dividend, as long as the firm raises additional financing to continue its

predetermined investment policy [see Miller and Modigliani (1961) for the first theoretical analysis of this issue].

Example 3

But does this firm value effect also apply to shareholders? After all, the €15 annual dividend payment corresponds to a dividend per share of €1.50, which at a required rate of return of 10% seems to translate into a share price of €15. However, this logic is flawed. The dividend per share in one year will be €1.50, but it will be smaller in subsequent years because there will be more shares outstanding after the equity issue.

Figure 3 illustrates what happens over the following 10 years in this example

Figure 3: Share Price with Equity Issuance

Year	Shares Outstanding Start of Year	Dividend	Dividend Per Share	Number of Shares Issued	Shares Outstanding Year End
1	100.00	15.00	0.1500	5.26	105.26
2	105.26	15.00	0.1425	5.54	110.80
3	110.80	15.00	0.1354	5.83	116.64
4	116.64	15.00	0.1286	6.14	122.77
5	122.77	15.00	0.1222	6.46	129.24
6	129.24	15.00	0.1161	6.80	136.04
7	136.04	15.00	0.1103	7.16	143.20
8	143.20	15.00	0.1048	7.54	150.73
9	150.73	15.00	0.0995	7.93	158.67
10	158.67	15.00	0.0945	8.35	167.02

At the end of the first year, the firm pays a dividend per share of €0.15. Firm value declines to €95 or €0.95 per share after the dividend payment. The firm then needs to issue 5.26 [=5/0.95] more shares, increasing the number of shares outstanding to 105.26. At the end of the second year, the total dividend is still €15, but divided by 105.26 shares, this implies a dividend per share of only €0.1425. The firm will again have to issue €5 worth of shares. The share price after the dividend payment has now declined 0.9025 [=95/105.26], so the firm will have to issue 5.54 [=5/0.9025] new shares. This will repeat indefinitely. However, note that today's price per share is not affected. The expected dividend per share in year 1 is €0.15, declining at a 5% rate annually. We can therefore value this as a growing perpetuity with a growth rate of –5%.

The value of a cash flow C_1 starting one year from now, and growing at a rate of g%, with a required rate of return of r% is[2]

$$\frac{C_1}{r-g}$$

Thus, the value of a share in the company is: €1.00 [=0.15/ (0.10-(-0.05))]. This is exactly the same as the share value with a dividend payment of €0.10 per share annually. Both firm value and share price are unaffected by the decision to increase the payout. This result is also known a Miller and Modigliani's dividend irrelevance

[2] See Appendix II for derivation of this formula.

proposition. It says that the value of the firm is unaffected by dividend policy as long as investment policy is fixed.

If the firm decided to pay the €15 out as a dividend, we would see the share price decline over time, which is not the case if the firm pays €10 out as a dividend. However, the investor is not worse off, because the decline in share price is compensated by a higher dividend. This is illustrated in the following figure.

Figure 4: Evolution of Dividends and Capital Gains

Year	Share Price at the Start of Year	Dividend Per Share	Capital Gain	Share Price at End of Year	Total Return
1	1.0000	0.1500	-0.0500	0.95	10%
2	0.9500	0.1425	-0.0475	0.90	10%
3	0.9025	0.1354	-0.0451	0.86	10%
4	0.8574	0.1286	-0.0429	0.81	10%
5	0.8145	0.1222	-0.0407	0.77	10%
6	0.7738	0.1161	-0.0387	0.74	10%
7	0.7351	0.1103	-0.0368	0.70	10%
8	0.6983	0.1048	-0.0349	0.66	10%
9	0.6634	0.0995	-0.0332	0.63	10%
10	0.6302	0.0945	-0.0315	0.60	10%

The annual return is 10% for every year, made up of a 15% dividend yield and a 5% capital loss. Thus, the investor takes more in dividend income, but sacrifices stock price appreciation. If investors do not want this outcome, they can reinvest part of the dividend, so that their portfolio holdings in the company continue to be €1. The following figure illustrates this strategy

Figure 5: Keeping € Investment in the Firm Constant

Year	Shares Held at Start of Year	Share Price at Start of Year	Share Price at Year End	Dividend Per Share	Total Dividend Received by Investor	Dividend Reinvested	Shares Purchased	Total Shares Held	Portfolio Holdings
1	1.000	1.000	0.950	0.150	0.15	0.05	0.053	1.053	1.00
2	1.053	0.950	0.903	0.143	0.15	0.05	0.055	1.108	1.00
3	1.108	0.903	0.857	0.135	0.15	0.05	0.058	1.166	1.00
4	1.166	0.857	0.815	0.129	0.15	0.05	0.061	1.228	1.00
5	1.228	0.815	0.774	0.122	0.15	0.05	0.065	1.292	1.00
6	1.292	0.774	0.735	0.116	0.15	0.05	0.068	1.360	1.00
7	1.360	0.735	0.698	0.110	0.15	0.05	0.072	1.432	1.00
8	1.432	0.698	0.663	0.105	0.15	0.05	0.075	1.507	1.00
9	1.507	0.663	0.630	0.100	0.15	0.05	0.079	1.587	1.00
10	1.587	0.630	0.599	0.095	0.15	0.05	0.084	1.670	1.00

The investor starts with 1 share held at the start of the year. The investor receives a dividend of €0.15, but reinvests €0.05 in the firm. These funds are employed to purchase 0.053 new shares at a price of €0.95. At the end of the year, the investor now holds 1.053 shares worth €0.95 each, for a total portfolio of €1.00. This scenario continues in the subsequent 10 years.

In sum, investors can decide for themselves how much they want as a 'net' dividend and how much they want to reinvest in the firm. Firms cannot affect value by changing dividend payout policy, as long as investment decisions are fixed.

Example 4

Could the firm in the above example have increased its value if it decided to employ the €10 of excess funds to repurchase shares instead of paying a dividend? Again, the answer is no. If the firm employs the funds to repurchase shares, there will be fewer shares outstanding and each share is worth more. However, the value of the firm as a whole is unaffected. A shareholder in the above scenario can expect a 10% share price appreciation annually, but no dividend income. The following figure lists the relevant variables in case of a share repurchase.

Figure 6: Share Repurchase Instead of a Dividend Payment

Year	Shares Outstanding Start of Year	Price Per Share at Year-End	Shares Repurchased	Shares Outstanding at Year End
1	100.00	1.10	9.09	90.91
2	90.91	1.21	8.26	82.64
3	82.64	1.33	7.51	75.13
4	75.13	1.46	6.83	68.30
5	68.30	1.61	6.21	62.09
6	62.09	1.77	5.64	56.46
7	56.45	1.95	5.13	51.32
8	51.32	2.14	4.67	46.65
9	46.65	2.36	4.24	42.41
10	42.41	2.59	3.86	38.55

If an investor wants some income from the shares, the investor can simply sell some shares on the open market to maintain their ownership in the firm at €1. Note that investors in the firm who buy shares back are not taking on more risk by having returns in the form of capital gains. It is completely up to investors to determine how much exposure they want to the firm. If they want less exposure, they can sell their stock. Thus, the firm's choice between dividends and capital gains has nothing to do with the risk appetite of investors.

In sum, the irrelevance argument of payout policy suggests that firms cannot create value when changing their payout policy as long as the level of investment is held fixed. An investor who does not receive enough income can always sell some shares to create a home-made dividend. Similarly, investors who do not want the dividends can use them to purchase more shares and maintain or increase their ownership in the company.

We now relax the perfect capital market assumptions one by one to examine their effect on optimal payout policy.

Personal Taxes and Dividend–Repurchase Choice

In the above example, investors were indifferent between dividends and repurchases because their returns were exactly the same in both scenarios: 10%. Investors did not care whether they received a 10% capital appreciation or a 10% dividend yield, or any combination between the two. However, this is not the case if the personal tax rate on dividends is different from the personal tax on capital gains. Investors then need to decide whether they value a 10% capital gain more than a 10% dividend. This depends on two factors:

- The statutory tax rates on dividends and capital gains
- The expected holding period of the investor

Even if the two tax rates are the same, the payments of dividends have immediate tax consequences, but were dividends not paid, but rather reinvested to produce capital gains, the tax consequences arise when the shares are sold. If the investor does not plan on selling their shares for say 10 years, the *effective* capital gains tax rate is much lower than the statutory capital gains tax rate.

The firm's decision is then one of using that distribution method which imposes the lowest personal taxes on investors. In some countries, this decision is straightforward. For example, in the United States, there are virtually no investors who pay a lower tax on dividends than on capital gains.[3] The conclusion is that, from a tax perspective, U.S. companies should never pay dividends. Capital gains are virtually always taxed lower.

The situation in, for example, the U.K. is less straightforward. The effective tax rate on dividend payments for individuals in the highest bracket is 25%. The capital gains tax is 40% for those individuals; however, investors who hold shares for longer periods of time can exclude some gains from taxes. For a holding period of 10 years or more, 40% of the gains can be excluded. This implies that the actual tax rate is 40% of 60% of the gain or 24%. Moreover, there is the effect of deferment—holding shares for 10 years implies you only pay capital gains taxes in 10 years. The implication is that U.K. companies should pay dividends if most of their investors have a short-term holding period, while they should repurchase shares if most of their investors have a long-term holding period.

The fact that the method of payout depends on the tax preference of investors leads to what is called *dividend clienteles*. That is, firms attract a clientele of investors who favour the payout policies adopted by the firm. Firms with high payouts will attract investors who pay low taxes on dividends, while firms with low payouts or payouts through repurchases attract investors who pay low taxes on capital gains. Because the investors have chosen investments based on their current payout policy, the firm does not benefit from changing its policy.

While the dividend clientele argument has some appeal, we note two caveats:

- As the above discussion suggests, in the US most investors prefer capital gains, yet many firms still pay dividends

[3] The only major exception is corporations who receive dividends from their ownership in other corporations. They only have to pay taxes on 30% of the dividend. This reduces the effective tax on dividend income to 30% of the corporate tax rate of 35%, which is 10.5%.

- If investors focus too much on payout policy in their portfolio decisions, they are likely to end up with a portfolio that is less diversified and may lack exposure to certain sectors of the economy

The dividend clientele argument does not necessarily rely on taxes alone. If, for whatever reason, certain groups of investors prefer companies with certain payout policies, they could also form a dividend clientele.

Asymmetric Information

In this section, we discuss the choice between paying dividends or repurchasing shares when investors have less information about the prospects of the firm than managers. Two separate questions need to be addressed:

- Are firms indifferent between dividend payments and repurchases?
- Will payout policy affect the investment policy of the firm so that we can no longer rely on the irrelevance result?

Signalling and Underinvestment

We will deal with the second question first. In the section on Irrelevance, we argued that firm value does not depend on payout policy, as long as investment policy is fixed. But, if the market is poorly informed about the firm's prospects, would firms have an incentive to give up some of their investment? Miller and Rock (1985) argued that this is exactly what will happen. The market will interpret a dividend payment (or a repurchase) as a signal of quality, which will create an incentive for the firm to underinvest, so that more funds are available to signal quality.[4] The surprising result of their analysis is that high quality firms will underinvest more, because they can afford it, and therefore have the greatest incentive to signal.

This dividend signalling theory has several implications:

- Firms will pay dividends to signal quality to the market
- Firms will be very reluctant to cut their dividend because that will provide a negative signal
- Firms will not increase their dividend unless they feel comfortable that they can maintain the dividend in the future; as a result, the pattern in dividend payments will be much smoother than the pattern in earnings or cash flows
- Dividend increases are associated with positive stock price changes
- Dividend cuts are associated with negative stock price changes
- Firms may forego projects that add value to the firm in order not to have to cut the dividend

Note that this is self reinforcing: firms are reluctant to cut dividends—investors know this and hence interpret dividend cuts to indicate a serious problem, making firms more reluctant to cut dividends.

Thus, dividend policy is employed to convey information at the cost of underinvestment. This signalling argument also applies to repurchases, except that repurchases are generally not considered permanent by investors. That is, if a firm repurchases shares

[4] See also Bhattacharya (1979) for an analysis of dividend signalling.

in one year, the market generally does not expect this to continue in the future. Many observers, therefore, argue that the signalling power of repurchases is weaker than that of dividends to communicate long-run prospects for the firm.

Signalling and Undervaluation

There is a second angle to the asymmetric information argument, which does not require the firm to invest less than optimal. If managers are better informed about the prospects of the firm than investors, they may be able to use payout policy to rectify undervaluation. By increasing dividends or repurchases, managers can inform the market about the true quality of the firm. Dividends are much less flexible than repurchases in this context, because they entail commitment for the future and because they are generally paid periodically. Repurchases may work better to correct undervaluation, especially when the firm already has a repurchase programme in place. In that case, the firm can repurchase shares in the open market whenever it feels that the current share price is too low, given the firm's prospects.

There is a third option, which is to pay a special dividend. A special dividend is not different from a regular dividend, except that through its designation, investors should see it as a one-off. Special dividends are less flexible than repurchases, but more flexible than regular dividends. As discussed earlier, mechanisms that are less flexible may have more signalling power, however. The following figure summarizes the trade-off between flexibility and signalling power.

Figure 7: Different Payout Options in Terms of Flexibility and Signalling Power

	Ordinary Dividend	Special Dividend	Share Repurchase
Flexibility	Low	Medium	High
Signalling Power	High	Medium	Lower

Despite the apparent appeal of special dividends as a signalling mechanism, DeAngelo et al. (2004) find that, at least in the United States, the number of firms paying special dividends has declined over time.

In sum, from a signalling perspective, dividends may be preferred over repurchases because they provide less flexibility to the firm.

There is another drawback to repurchases, as pointed out by Brennan and Thakor (1990). Suppose that there is an information gap between management and shareholders. Moreover, suppose that some shareholders are better informed than others, so that the information gap for them is smaller. What happens when a firm engages in a share repurchase under these conditions? Shareholders with the least information may decide to sell because of liquidity or other reasons. However, shareholders with more information about the true prospects of the firm may decide to hold on to their shares if they know that the firm's prospects are likely to improve. Thus, a repurchase does not treat all shareholders equally. A dividend accrues to all shareholders and therefore treats all shareholders equally. This discriminatory aspect of repurchases may make them less appealing to certain groups of investors.

Managerial Self-Interest

Jensen (1986), among others, has argued that managers often have the incentives or inclination to grow the firm beyond its optimal size through investments and acquisitions that do not add value to the firm. This non-value maximizing behaviour is sometimes

called empire building. Shareholders are concerned about this, and can take various actions to curtail these actions.

Some managers may not wish to engage in empire-building and would like to inform the market about their intentions. Statements to this effect may not be very credible because there is no true commitment. Payout policy can help, however. By setting payouts at a certain level, managers commit to returning funds to shareholders. Thus, payouts act as a bonding mechanism. Again, ordinary dividends may be more powerful than special dividends and repurchases because only ordinary dividends are expected to be repeated.

If this bonding argument is valid, we should find that managers of firms who cut their dividend are more likely to be replaced. This is indeed to the case, at least based on U.S. evidence [see Kaplan and Reishus (1990)].

One concern regarding the validity of this explanation is that managers can always make high payouts, and use capital markets to raise the necessary funds through equity or debt issues. Thus, firms must either be prohibited from accessing capital markets, or the mere fact that they access capital markets must lead to increased scrutiny, which affects the ability of managers to engage in self-serving behaviour [see Easterbrook (1984)].

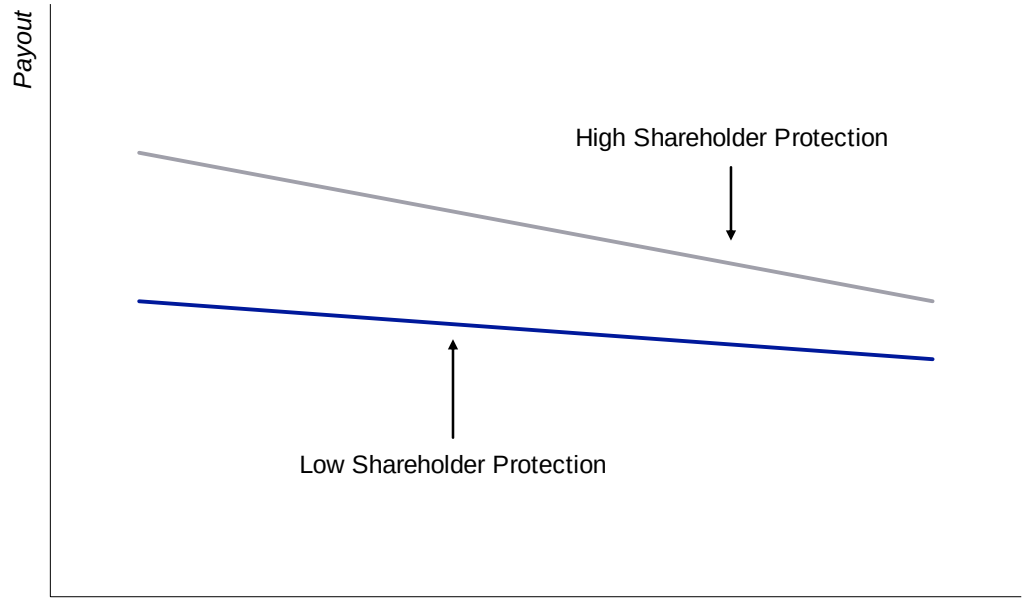
Managerial Self-Interest and Shareholder Rights

An argument related to managerial self-interest deals with shareholder rights across countries. This argument has been proposed and developed by LaPorta et al. (2000).

If the legal system in a country does not give shareholders means to control the firm and its managers, these shareholders may be unsure that they will earn a proper return on their investment. We would expect payouts to be higher in countries where shareholders are better protected. Moreover, when shareholders are better protected, they are willing for firms to keep funds for reinvestment, because the shareholders know that they can get their money out at a later time, when the returns on the investment have been realized. This negative relationship between payout and investment opportunities does not necessarily hold in countries with poor investor protection, because shareholders may prefer to be paid before insiders get a chance to dissipate the funds.

The following figure illustrates the relationship between payout and growth opportunities in countries with different legal regimes, based on this argument.

Figure 8: Outcome Model of Dividends

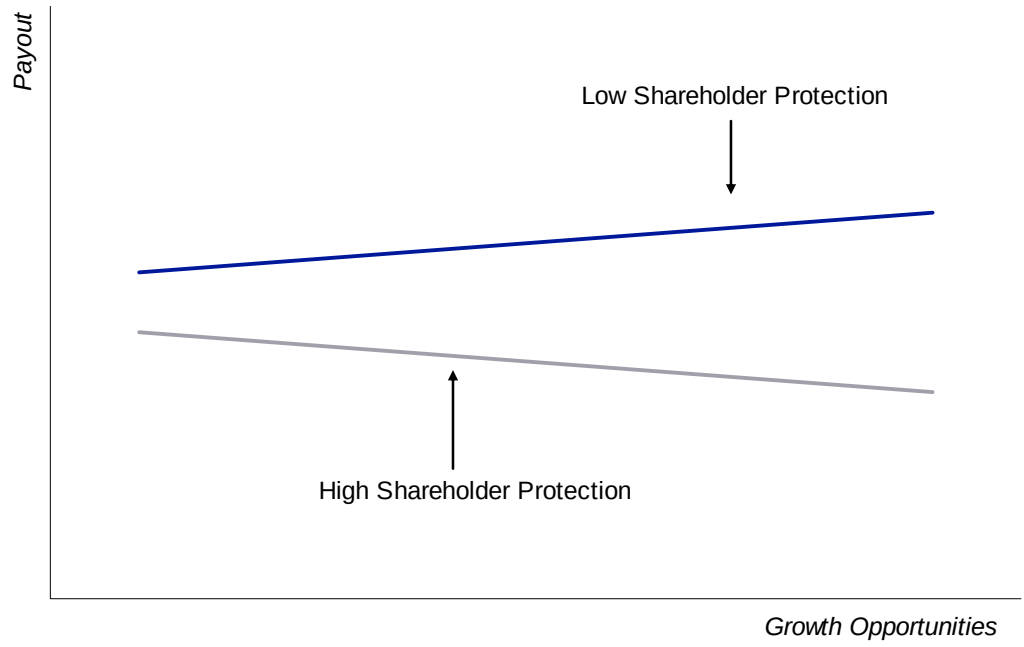


LaPorta et al. (2000) call this argument the Outcome Model of Dividends.

Using the same structure, another relationship is also possible. This alternative relationship assumes that payouts act as a substitute for shareholder protection. That is, in countries where shareholders have few rights, insiders use payout policy to bond themselves to their minority shareholders (this is essentially the same argument as was made in the previous section). Why would insiders do this? They would only do this if they may need minority shareholders in the future for additional financing. Thus, firms with lots of investment opportunities may actually have higher payouts because they want to establish a reputation for returning funds to shareholders. Firms with few opportunities do not need to access capital markets and, consequently, have no need to establish a reputation. This hypothesized relationship should not hold in countries where shareholders are well-protected because managers do not need to establish a reputation for concern for minority shareholders.

The following figure illustrates the relationship between payout and growth opportunities in countries with different legal regimes, based on this argument.

Figure 9: Substitute Model of Dividends



LaPorta et al. (2000) call this the Substitute Model of Dividends.

Using data for 4,103 companies from 33 countries, LaPorta et al. (2000) find support for the outcome model of dividend policy. Firms in countries with good shareholder protection pay out more in dividends than firms in countries with poor shareholder protection. Moreover, the relationship between dividend payout and growth opportunities is negative in countries with good shareholder protection, but not in countries with poor shareholder protection.

Investor Preferences

According to various "investor preference" arguments, investors favour one payout form over another for unknown reasons. It can thus be called a behavioural argument because there is no economic rationale behind these preferences. Companies cater to these preferences by choosing the payout method currently favoured by investors [see Baker and Wurgler (2004)].

For this argument to work, it must be the case that share prices of firms that cater to investor preferences are higher than share prices of firms that do not (or managers believe this to be the case). Otherwise, there is no reason for a firm to adjust its payout policy. Given that the price differential is based on investor irrationality, this argument also relies on limits to relative value investing. If not, a relative value investor would simply sell short the shares of the firms that cater to investor demand and purchase shares of firms that do not. The price difference between the two sets of firms would be the profit for the relative value investor.

Monitoring and Dividend Clienteles

Suppose that investors generally prefer returns in the form of capital gains, whether this is for tax reasons or not. However, suppose that a subset of investors prefer dividend income. Would it ever make sense for firms to cater to this small subset? Allen et al. (2000) argue that it could make sense if these investors are more skilled at monitoring

the firm and its managers than other investors. In other words, firms cater to particular investors because these investors are better at assessing the performance of the company and taking action if necessary.

Managers might cater to these investors for at least two reasons:

- It may be a way for high quality managers to bond themselves and indicate that they are not afraid of being closely monitored
- The monitors may actually provide valuable advice to management, which enhances the value of the firm

Note that causality is different in the two explanations. The first explanation suggests that high quality firms are signalling quality by agreeing to be monitored. The second suggests that monitoring itself may enhance the value of the firm.

Managing EPS

Conducting a share repurchase right before the end of the firm's fiscal year is likely to have little effect on the overall earnings of the firm. However, the reduction in the number of shares outstanding will have an immediate impact on Earnings Per Share. If investors do not see through this, then the firm could, at least in the short run, increase its share price. Executives may also engage in this practice because their compensation contracts target certain levels or growth rates in EPS. Over time, the ability to repurchase shares strategically may allow the firm to deliver a pattern of EPS that is smoother (less volatile) than it would be otherwise. If the market values this reduction in volatility, value is created.

It is important to establish that the arguments presented above are only valid if investors are not fully rational. Rational investors should not care about the volatility of individual shares because this volatility matters little in a portfolio context. They should also see through the fact that the increase in EPS achieved through a share repurchase is also temporary. The following example illustrates the second point.

Example 5:

Suppose that a firm has two assets:

- Productive assets of €80, earning a rate of return of 20%
- Cash of €20, earning a rate of return of 5%

Assume also that:

- Earnings on these two sets of assets are all paid out as dividends and so there is no growth
- The firm has 100 shares outstanding, so each share is trading for €1

Earnings of the firm are €17 [= 80×20%+20×5%], or €0.17 on a per share basis. Thus, the shares of this firm are trading at a P/E ratio of 5.88 [=1/0.17].

If the firm employs all of its cash holdings, right before the end of the year to repurchase shares, total earnings will not be affected because the repurchase is conducted when virtually all the interest has already been earned. However, the number of shares declines from 100 to 80, thereby increasing EPS from €0.17 to €0.2125.[5] If investors are irrational and apply the same P/E to this level of EPS, the share price will indeed increase to €1.25 [=0.2125×5.88].

When investors are rational, however, this repurchase should not have any consequences for the share price. The firm has reduced its asset base by €20 and the value of the firm should therefore decline by €20. Shares should remain at €1 per share.

It is correct to note that the decline in shares is much smaller than the expected decline in profits, now that the cash holdings are no longer earning a rate of return. The number of shares declines by 20% (from 100 to 80), but profits only decline by 5.88% (from 17 to 16). One might argue that, even if investors are rational, this should warrant a price increase. However, that argument would be incorrect. When the firm had assets consisting of some cash, the earnings of the firm were safer, because the returns on the cash were virtually guaranteed. Once the cash is gone, the earnings stream becomes riskier. As a result, investors are only willing to pay €80 for an earnings stream of €16, which implies that the P/E ratio of the firm will decline from 5.88 to 5.00.

The only reason why the ability to smooth or manage EPS through share repurchase may have true economic consequences, is if the firm has entered into contracts that take into account EPS or rely on EPS to draw inferences.

Stock Option Dilution

When firms employ stock options to compensate managers and employees, the number of shares outstanding increases as the options are exercised. This has negative consequences for reported EPS. As discussed previously, if managers believe that this EPS effect has an effect on share value, then firms may employ share repurchases to offset the effect of the share issues.

[5] This is a dramatized example. In practice, the denominator of the EPS calculation is harder to manipulate because it is the average number of shares trading over the year. A transaction close to year end would have limited impact. Nevertheless, the EPS impact of a share repurchase does not necessarily mirror the true economic effect so manipulation is sometimes possible and this is an argument that is often heard in practice.

Changing Capital Structure

Each time a firm makes a distribution to its shareholders, be it through dividends or share buybacks, it is returning capital to equityholders and hence the value of the firm's equity is reduced. This increases the fraction of the firm financed through debt. If the distribution is small and repeated yearly or even more frequently, the actual changes in the firm's debt-to-equity ratio are small. However, distributions are also a mechanism through which firms can dramatically increase the level of debt financing in the firm.

Suppose that a firm is pleased with its operations (i.e., the asset side of the balance sheet), but comes to the conclusion that it does not employ enough debt financing. The best way to introduce more debt financing to the firm, without affecting its current operations, is to issue the debt and immediately return the proceeds to its shareholders. To decide whether this happens through a repurchase or through a dividend, the firm should consider the items discussed in previous sections of this paper. What is important in this context is that a distribution conducted to change capital structure can be quite substantial.

Residual Distribution Policy

A residual distribution policy is one where firms make their investment decisions based on investment opportunities and available funds. If they do not have sufficient funds available to make investments, they consider accessing capital markets. If they have excess funds (and they do not believe they will need the funds in the near future), they return the remainder to shareholders. The exact method employed does not really matter, but the firm could take into account some of the previous arguments, such as taxes, or the ability to manage EPS.

If firms follow a residual policy, their total payout is as volatile as the excess cash flows generated by the firm. There is no attempt to smooth payouts, whether they are in the form of dividends or repurchases. Under this scenario, payouts do not convey information to the market, albeit that the amount of payout may still be employed by market participants to gauge how much is being invested. In other words, even if the firm does not employ payout policy to convey information, the firm cannot prevent investors from using the payout to try and infer how the firm is performing.

Summary

- The table below lists the factors that are important in the choice between dividends and repurchases as a payout mechanism

Factor	Dominating Payout Form
Taxes	Depends
Conveying information	Depends on time horizon
Management bonding	Dividends
Shareholder rights	Depends on other factors
Investor preferences	Depends on preferences
Attracting monitors	Depends on other factors
Managing EPS	Repurchases
Changing capital structure	Depends on other factors
Residual policy	Depends on other factors

Survey Results

In this section we present the results of the survey pertaining to corporate dividend and share repurchase policy but first discuss the questions we asked.

Survey Questions

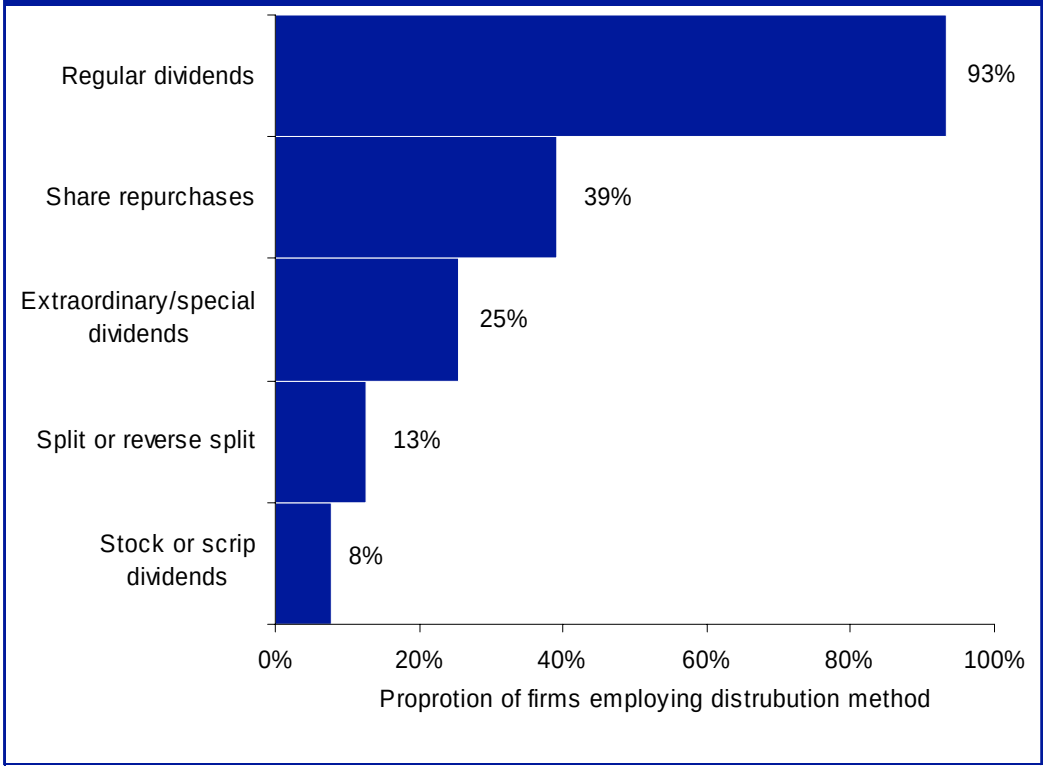
The survey is designed to shed light on the practical relevance of various theoretical considerations discussed in the previous section. In particular, we have asked questions to study the following issues:

- How do firms choose between dividends and share repurchases?
- Did they pay a special dividend or a stock dividend over the last 5 years?
- What dividend policy do firms follow, and what items do they target in their policy (payout, yield, dividend level, dividend growth)?
- How much have firms paid out and in what form over the last 5 years?
- How important is maintaining the dividend and which actions would firms take before they would consider cutting the dividend?
- Why have firms decided to pay a special dividend, if they did so?
- What factors have firms considered when deciding to repurchase shares?

Preferred Distribution Method

We started by asking companies which distribution methods they had employed over the last five years. Respondents could select more than one option. Figure 11 provides an overview of the responses for those firms that employed at least one of the methods.

Figure 11: Distribution Methods



Q5.1: "Over the last five years, have you done any of the follow ing?" N=205.

Regular cash dividends are clearly the preferred distribution mechanism, employed by 93% of all respondents, followed by share repurchases which have been employed by 39% of all firms. A quarter of all firms have paid a special dividend. For completeness, we also asked whether companies split their stock or paid a stock dividend.[6] Both happen rather infrequently: 13% of the firms have split their stock and only 8% have paid a stock dividend.

There are important differences in distribution methods across the world. Regular cash dividends are most important in every region. However, special dividends are more important than buybacks in Asia (excluding Japan), Australia and New Zealand, Germany, and Latin America. In North America, share repurchases are almost as important as regular dividends, with 95% of the respondents paying regular dividends and 85% of the respondents buying back shares.

How the Choice of Distribution Mechanism is Made

In this section, we investigate which factors firms take into account when deciding on the choice among regular dividends, special dividends, and share repurchases, based on the theoretical discussion in the previous section. In this part of the survey, we only ask those companies who have distributed funds through at least one of the three distribution mechanism. Figure 12 lists the five factors we proposed, together with the number of respondents ranking these factors as important or very important, corresponding to a 4 or 5 on a scale ranging from 0 to 5.

[6] Note that neither of these actions actually distributes any cash to shareholders.

Figure 12: Factors Determining the Method of Distribution

Factors	%4 or 5	N
Signalling	39%	152
Flexibility in changing level of distribution	36%	151
Tax efficiency of the alternatives	31%	156
Attractiveness to different investors	30%	149
Accounting implications	29%	154

Q5.3: "How important are the following factors in your choice between paying Regular Dividends, paying Special Dividends and Repurchasing Shares?" Scale is Not Important (0) to Very Important (5).

None of the factors receive overwhelming support, but they all receive moderate support. The signal sent to capital markets is considered to be important by 39% of the survey participants, followed by the flexibility, which is listed as being important by 36% of the participants. Tax efficiency, attractiveness to investors, and accounting implications follow with 31%, 30% and 29% of the firms ranking these factors at the high end of the scale.

Figure 13 shows the relative importance of these factors across different regions.

Figure 13: Factors Determining the Method of Distribution - Regional Ranking

	Asia excluding Japan	Australia & New Zealand	Germany	Japan	Latin America	North America	Western Europe excluding Germany
Signalling	2	1	1	4	1	1	2
Flexibility in changing level of distribution	5	3	3	2	2	1	3
Tax efficiency of the alternatives	3	5	2	5	3	4	1
Attractiveness to different investors	1	3	5	1	4	5	4
Accounting implications	4	1	4	3	4	3	5

Q5.3: "How important are the following factors in your choice between paying Regualr Dividends, paying Special Dividends and Repurchasing Shares?" Table shows relative ranking of factors by firms in different regions. See Appendix III for *N* by region.

The signal sent to capital markets is one of the top two answers in all regions, except for Japan. This is perhaps the case because dividends are generally small in Japan and have relatively little signalling power as a result.

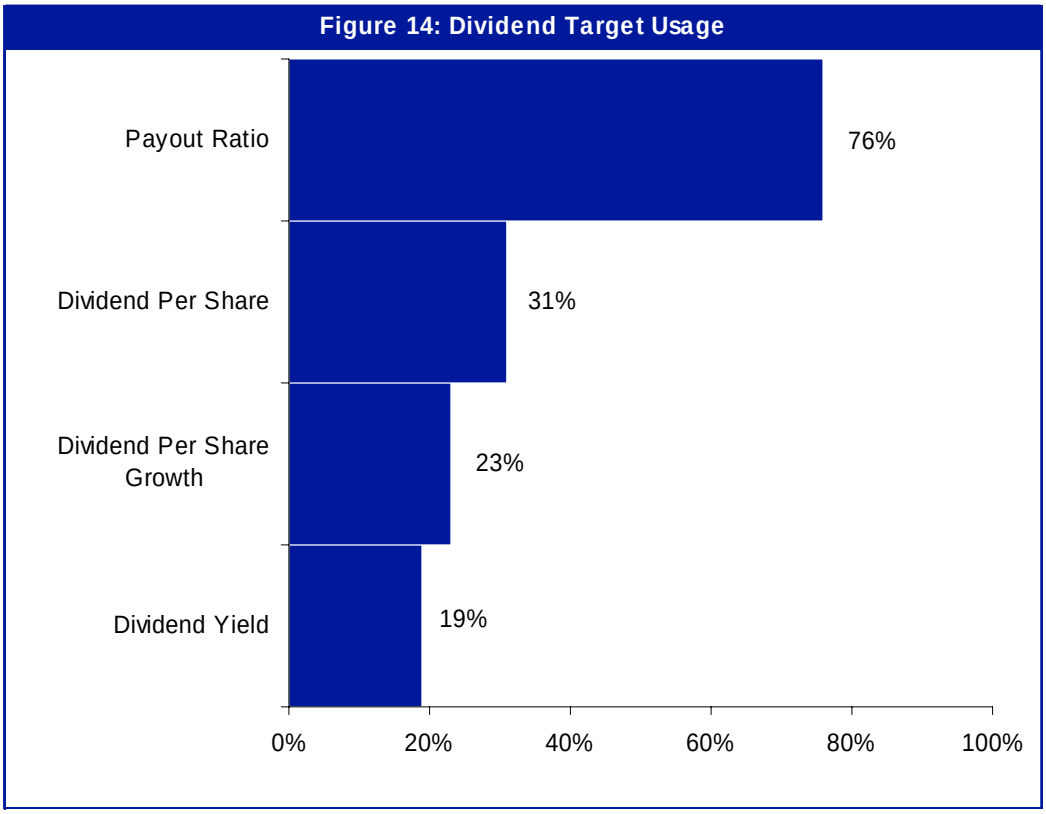
Understanding Regular Dividends

In this section, we document how firms set dividend policy.

Targets

We first ask how firms set their dividend targets, allowing firms to select multiple targets. Figure 14 shows the results:

Figure 14: Dividend Target Usage



Q5.6: "For which of the following do you have target ranges and what are those ranges?" N=106.

By far the largest fraction of firms (76%) have a dividend payout ratio target in mind; dividend per share targets are second-most popular, chosen by 31% of firms. Dividends likely increase as the firm grows, and we suspect that these companies set dividend per share targets in the short-run, while setting other types of targets in the long-run. 23% of all respondents have targets for dividend per share growth, while 19% of the firms have specific targets on dividend yield.

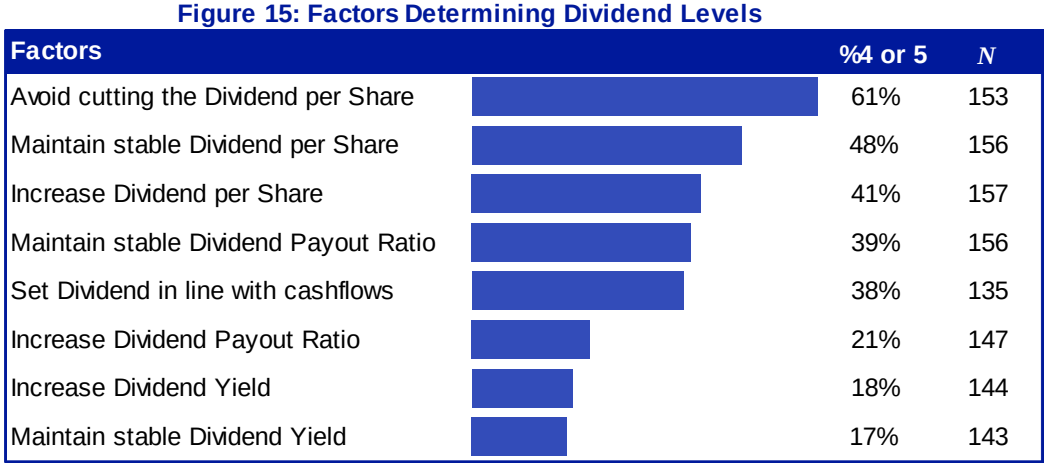
The primary target is the dividend payout ratio in all regions of the world, except for Japan where 50% of the companies have a payout ratio target, but 80% have a dividend per share target. Dividends in Japan are fairly low; moreover they have grown relatively little over time as the economy has grown slowly or not at all. This may explain why Japanese firms have focused on the dividend level, instead of a payout ratio. Two other interesting differences emerge. First, North American firms also have a payout ratio as the most common target, as listed by 64% of the respondents. However, a substantial fraction of North American firms (45%) have a Dividend Per Share growth target. Second, 41% of Asian (ex-Japan) firms have a dividend yield target; this is a higher fraction than anywhere else in the world.

Dividend Patterns

While the majority of the firms worldwide have a target payout ratio, this does not mean that they will always stick to the ratio—the target may be a soft target, rather than a hard target, a target they have in mind, but a target from which they are willing to deviate in some circumstances. For example, if firms believe in dividend signalling, they may prefer to have a smooth pattern in dividends per share, rather than a stable payout ratio. We asked survey participants about the importance of these different objectives. Figure 15 illustrates the importance of different objectives in setting dividend per share levels. It

lists the fraction of firms that rank each objective as a 4 or 5 on a scale going from 0 (Not Important) to 5 (Very Important).

Figure 15: Factors Determining Dividend Levels



Factors	%4 or 5	N
Avoid cutting the Dividend per Share	61%	153
Maintain stable Dividend per Share	48%	156
Increase Dividend per Share	41%	157
Maintain stable Dividend Payout Ratio	39%	156
Set Dividend in line with cashflows	38%	135
Increase Dividend Payout Ratio	21%	147
Increase Dividend Yield	18%	144
Maintain stable Dividend Yield	17%	143

Q5.7: "How important are the following objectives?" Scale is Not Important (0) to Very Important (5).

The primary objective firms have in mind when they set the dividend is to avoid cutting it in the future: 61% of all firms consider this to be important. This is followed by the desire to keep the dividend per share stable and to increase it; 48% of all firms believe that it is important to keep the dividend stable and 41% indicate that increasing the dividend is an important objective. The three highest ranked objectives all have to do with the dividend per share and not the payout ratio, nor the dividend yield. Thus, while most firms have a dividend payout ratio target, this does not mean that they apply this target rigidly. Instead, consistent with the dividend signalling arguments, firms try to keep the dividend stable, and avoid setting it too high today so that it may have to be cut tomorrow.

The next two objectives in terms of importance are keeping the dividend payout ratio stable (important for 39% of the firms) and setting dividends in line with the firm's cash flows (important for 38% of the firms). 21% of the firms would like to increase their payout ratio. Maintaining a stable dividend yield or increasing the yield are important for less than 20% of the companies.

Figure 16 ranks the factors in order of importance across different regions.

Figure 16: Factors Determing Dividend Levels - Regional Ranking

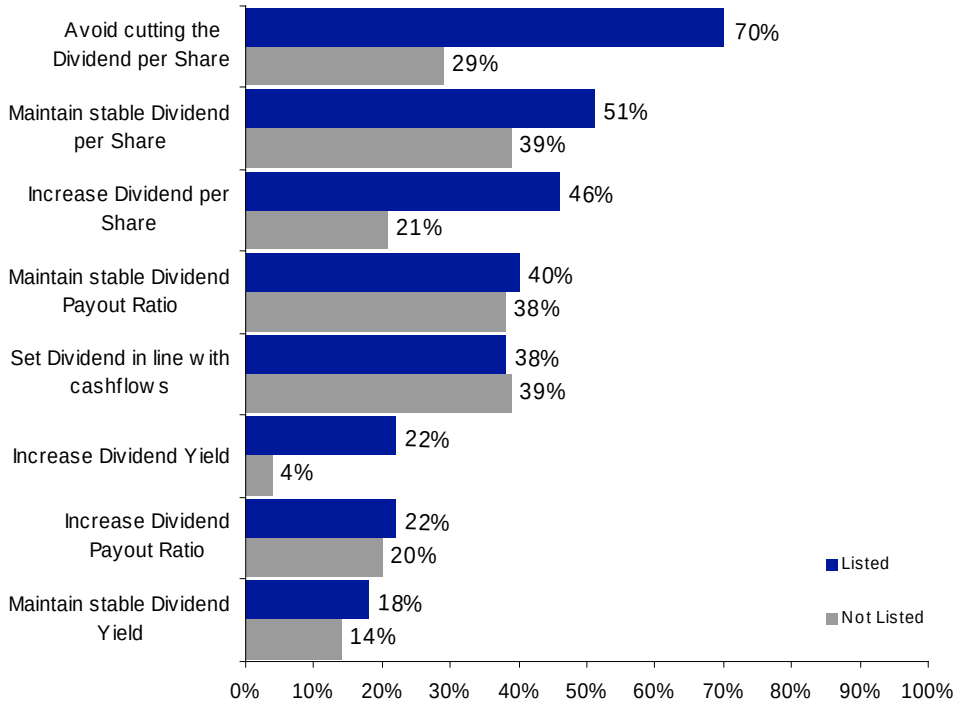
	All	Asia excluding Japan	Australia & New Zealand	Germany	Japan	Latin America	North America	Western Europe excluding Germany
Avoid cutting the Dividend per Share	1	1	2	1	3	4	1	1
Maintain stable Dividend per Share	2	2	3	2	1	3	3	2
Increase Dividend per Share	3	6	3	5	2	6	2	3
Maintain stable Dividend Payout Ratio	4	3	5	4	6	1	4	5
Set Dividend in line with cashflows	5	4	1	3	5	2	5	4
Increase Dividend Payout Ratio	6	8	6	6	4	5	7	7
Increase Dividend Yield	7	5	8	6	7	7	5	8
Maintain stable Dividend Yield	8	7	7	8	8	7	7	6

Q5.7: "How important are the following objectives?" Scale is Not Important (0) to Very Important (5).
See Appendix III for *N* by region.

Avoiding dividend cuts is the first or second response for all regions, except for Japan, where it ranks third, and Latin America, where it ranks fourth. In Latin America, the main objective of firms is to keep the dividend payout ratio stable. This is a substantial difference from the other regions, because keeping the payout ratio stable does imply some variability in the level of the dividend. This also suggests that firms in these regions will be more willing to cut the dividend level. Japanese firms' primary objective is to keep the dividend per share stable.

Not surprisingly, the choice of objectives when setting the dividend per share differs between listed and unlisted companies, as illustrated in Figure 17.

Figure 17: Response to Low Cashflows



Q5.7: "How important are the following objectives?" Scale is Not Important (0) to Very Important (5).

The overall findings described earlier apply mainly to listed companies, for whom dividend signalling is important. These firms therefore prefer a stable dividend and will avoid cutting the dividend if possible. Firms that are not listed, on the other hand, are less concerned with the information gap between the firm and its investors. As such, they are less concerned with the signalling power of dividends. The primary objective of these firms is to set the dividend in line with cash flows. Avoiding cutting the dividend per share is only fourth in the list of objectives for these firms, after the desire to maintain a stable dividend per share.

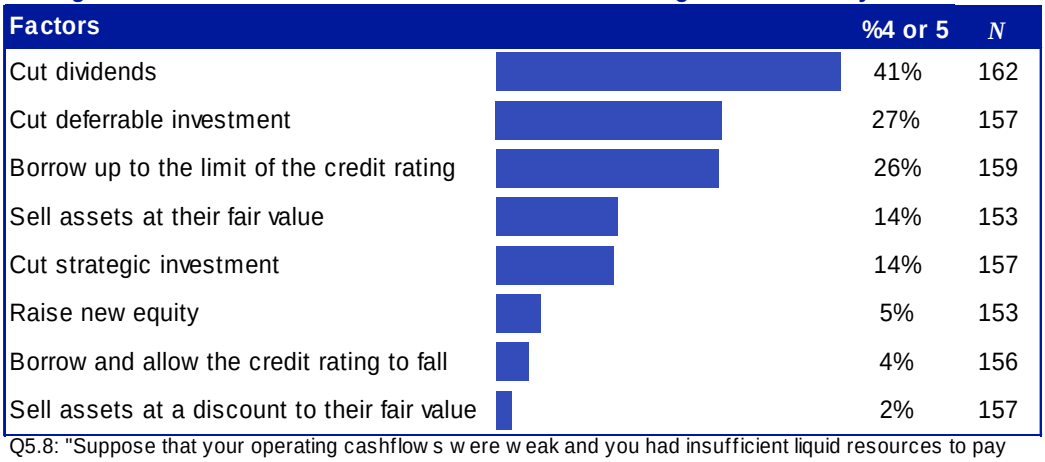
Responding to Low Cashflow

The results for the overall sample indicate that firms attempt to set their dividend so that they do not have to cut it. This assumes that companies will use enough foresight so that dividends are not increased today if this increase cannot be maintained in the future. It is not possible, however, to anticipate all possible events, and there may come a time when companies do not have sufficient cash flows available to continue investing and maintaining the dividend at the same time. We asked companies what actions they would take if they faced such a situation.[7]

More specifically, we listed a number of possible actions and asked companies how likely they would be to take each of these actions, on a six-point scale, where a zero is never and a 5 is very likely. Figure 18 shows the responses.

[7] Some of these findings are also discussed in the companion article CFO Views on the Importance and Execution of the Finance Function.

Figure 18: What to Do When You Do Not Have Enough Funds to Pay Dividends



Factors	%4 or 5	N
Cut dividends	41%	162
Cut deferrable investment	27%	157
Borrow up to the limit of the credit rating	26%	159
Sell assets at their fair value	14%	153
Cut strategic investment	14%	157
Raise new equity	5%	153
Borrow and allow the credit rating to fall	4%	156
Sell assets at a discount to their fair value	2%	157

Q5.8: "Suppose that your operating cashflow s w ere w eak and you had insufficient liquid resources to pay Regular Dividends at the most recent level. How likely w ould you be to take each of these actions?" Scale is Never (0) to Very Likely (5).

The action companies are most likely to take is to cut the dividend. It receives an average score of 2.9 and 41% of all firms believe that this is a likely outcome. In light of existing research and the fact that companies want to avoid cutting the dividend, it seems quite surprising that firms would not consider any other action first. However, it does suggest that firms are not willing to take actions that might not be in the long-term interest of the firm, just to maintain a dividend policy that is no longer in line with available cash flows. The second most likely action is to cut deferrable investment, with an average score of 2.4; 27% of the respondents consider this a likely response to the shortage of funds. 26% of the firms are likely to borrow money up to their credit rating limit to maintain the dividend. All other actions are much less likely: 14% of the firms would cut strategic investment and the same fraction would sell assets at fair value; only 5% of the firms would raise equity, 4% would borrow funds and allow their credit rating to decline and only 2% would sell assets below fair value. It is striking that there is a substantial difference between the fraction of firms that would sell assets below fair value and the fraction that would cut strategic investment. Both fractions are relatively low, but it is interesting that firms would much rather cut strategic investment than sell existing assets at a discount.

There are a number of differences in the response across regions. Firms in Australia and New Zealand would rather raise new equity than cut the dividends. This is perhaps the case because both countries have imputation tax systems that allow investors to offset their own tax bills by the corporate taxes paid by the firm, but only on the profits paid out as dividends. Cutting the dividend would therefore reduce this offset. Cutting the dividend is second in line though. Firms in Japan and North America would rather cut deferrable investment first in order to pay the dividend. If that is not sufficient, Japanese firms would cut the dividend too. North American firms would not—they prefer to take several other actions first. After cutting deferrable investment, North American firms would borrow money to pay the dividend, as long as they do not lose their credit rating. Next, they would sell assets at fair value and cut strategic investment. Only if all these actions are insufficient, would they resort to a dividend cut. The preferences of North American firms are thus very much at odds with those of firms elsewhere. One could argue that the first choice of North American firms, which is to cut deferrable investment, may be sensible. But this conclusion is not necessarily the right one. Even if an investment can be deferred, deferral is not free. North American firms are willing to pay this cost, presumably because they feel that the negative signal associated with the

dividend cut outweighs the cost of deferral. It is more surprising, however, that North American firms would actually cut strategic investments rather than cut the dividend. That said, distorting investment to signal quality to the market is one of the costs of signalling identified in the Theoretical Considerations section of this paper. It appears that this theory works particularly well in North America.

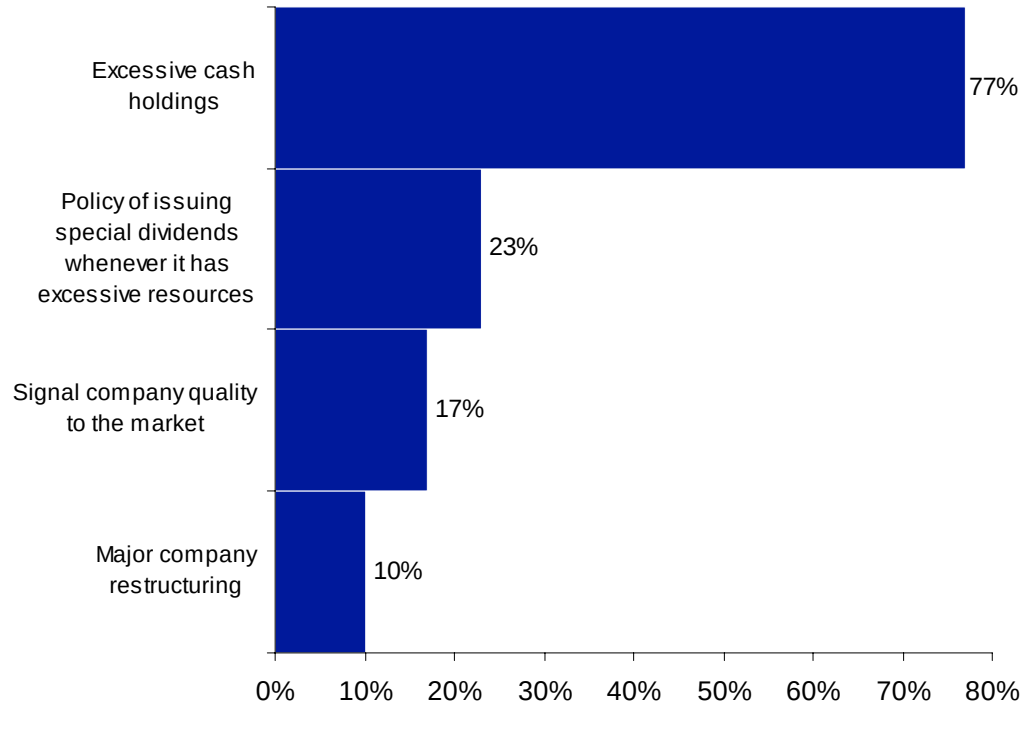
Could it be that North American firms attach too much weight to maintaining the dividend? This is plausible, but certainly not the only explanation. The quality of the signal sent through dividends is obviously higher for firms that have a longer track record of paying a stable or increasing dividend. If North American firms have a better track record of stable dividend payments than firms elsewhere, then their greater reluctance to cut the dividend is certainly warranted. This clearly requires further investigation.

When we look at the response for listed versus unlisted firms, we find that both groups would rather cut their dividend than do anything else. There is a difference between investment-grade and non-investment grade firms, however. Investment grade firms' first option is to cut deferrable investment rather than to cut the dividend. For non-investment grade firms and firms that are not rated, the dividend cut remains the number one choice, possibly because these firms have not built up as much of a track record in terms of dividends, resulting in less of a reluctance to cut the dividend. In addition, the cost of deferring investments may be too large for these firms.

Understanding Special Dividends

Only 25% of the firms in our survey have paid a special dividend. We asked companies why, allowing them to provide multiple answers. Figure 19 contains the responses.

Figure 19: Factors Determining Special or Extraordinary Dividends



Q5.9: "Why did you pay the Special or Extraordinary Dividend?" N=30.

77% of the firms paid a special dividend to distribute excess cash holdings, and another 23% actually have a policy of paying special dividends to distribute excess cash on a regular basis. 17% use special dividends to signal their quality to capital markets but only 10% pay the special dividend as a result of a major company restructuring. A number of companies provide other reasons (not shown in the figure), although a careful reading of the exact motives for these companies indicates that most of these can be classified as related to a restructuring as well.

Overall, special dividends mainly occur because firms have excess cash that they want to distribute, whether they have a policy of doing so or not.

Understanding Share Repurchases

As discussed in the section on the Preferred Distribution Method, 39% of the respondents who distributed funds in the last five years used share repurchases for some or all of the distribution. The following figure lists the factors that were important in the decision to repurchase shares, based on a six-point scale, ranging from 0 to 5. Firms that mark a factor with a 4 or 5 are assumed to be firms that believe a factor is important. We also list the average score for each of the factors.

Figure 20: Factors Determining Share Repurchases

Factors	%4 or 5	Average	N
Return excess capital to shareholders	46%	2.94	72
Increase the leverage of the Company	32%	2.23	69
Exploit temporary mispricing	27%	1.99	70
Increase EPS	26%	2.38	68
Tax efficient distribution	23%	2.20	70
Mitigate dilution from employee schemes	23%	2.03	69
Exploit persistent mispricing	13%	1.58	67
Concentrate equity holdings	9%	1.15	68
Manage EPS volatility	6%	1.18	67
Reduce the amount of capital	6%	1.04	67

Q5.11: "How important were the following factors in your decision to repurchase shares?" Scale is Not Important (0) to Very Important (5).

Only one factor receives substantial support: 46% of all participants indicate that the return of excess capital to shareholders is an important factor in their decision to buy back shares. Close to one third of the firms, 32%, mention that they bought shares back to increase the leverage of the company, while 27% bought shares back to take advantage of temporary mispricing in their companies' shares. All of these factors support the theoretical arguments discussed earlier.

26% of all respondents indicate that they bought shares back to increase reported EPS. Moreover, this factor receives an average score of 2.4, which is higher than the average score for leverage increases or exploiting mispricing. As indicated in the previous section, there is no theoretical reason to believe that an increase in EPS accomplished through a share buybacks actually creates economic value. The only exception to this is if firms have written specific contracts based on the level of EPS. We believe it is

unlikely, however, that this is the reason why firms want to increase reported EPS. There are two other possible underlying motivations which we believe are more likely:

- Firms want to increase EPS because shareholders and capital markets in general do not fully understand the mechanism through which this increase has been accomplished; as such, shareholders do ascribe value to the EPS increase
- Executives want to report increased EPS for other reasons; one possibility is that executive compensation contracts have been written based on EPS

Close to one quarter of the firms, 23%, indicate that they bought shares back to neutralize the dilution associated with employee stock option plans. Thus, firms are concerned with the implications of stock option plans on reported EPS and buy shares back offset this effect. Again, we are not sure that this concern is fully warranted. About the same fraction of firms buy shares back because they believe that this is more efficient from a tax perspective than alternative distribution forms.

The other factors receive much less support. Exploiting persistent mispricing, managing EPS volatility, concentrating equity holdings, or reducing the amount of capital available to the firm are not important in the decision to repurchase shares.

In sum, many of the factors that are important from a theoretical perspective also receive practical support. The one exception is the use of repurchases to increase EPS, which appears to be very important from a practical perspective.

Summary

- Dividends continue to be the most important distribution mechanism: 94% of all firms pay dividends, compared to 39% of the firms buying back shares
- When firms decide on the choice of distribution mechanism, they assign roughly equal weights to five factors:
  - The signal it sends to capital markets
  - The flexibility afforded by the distribution mechanism
  - The accounting implications
  - The tax efficiency of the alternatives
  - The attractiveness to different investors
- All of the above factors, except for the accounting implications, have strong theoretical support
- More than three quarters of the firms that pay dividends have a dividend payout ratio target. However, they are willing to deviate from that target when they set the level of the dividend. Firms set the dividend level so that they do not have to cut it; in addition it is important for companies to keep the dividend per share level stable or growing
- When firms are faced with insufficient cash flows to maintain the dividend, their first response is to cut the dividend, followed by cutting deferrable investment and borrowing up to the credit rating limit. The willingness of firms to cut the dividend when cash flows are insufficient reduces the relative signalling power of dividends over share repurchases

- A notable exception is the North American region where cutting dividends is only considered after several other options have been exhausted

- Firms pay special dividends as a return of excess funds to shareholders
- Firms repurchase shares to return excess funds to shareholders, to increase leverage, and to take advantage of temporary mispricing of their shares. Increasing reported EPS and mitigating dilution from employee stock option schemes also affect repurchase decisions, although less strongly

Appendices

Appendix I: References

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Appendix II: Formula Derivations

The Value of a perpetual cashflow

We follow the logic outlined by Brealey and Myers (2005).

Start with the general formula for the present value of a cashflow:

$$V = \sum_{i=1}^{\infty} \frac{C}{1+r} = \frac{C}{1+r} + \frac{C}{(1+r)^2} + \frac{C}{(1+r)^3} + \cdots$$

Define: $x := \frac{1}{1+r}$ and $a := Cx$ to give (1) $V = a(1 + x + x^2 + x^3 + \cdots)$.Multiply both sides by x to give (2) $Vx = a(x + x^2 + x^3 + \cdots)$. Subtract (2) from (1) to give $V(1-x) = a$ which expands to:

$$V\left(1 - \frac{1}{1+r}\right) = \frac{C}{1+r}$$

Multiply both sides by $1+r$ and rearrange to give:

$$V = \frac{C}{r}$$

Value of a growing perpetual cashflow

We again follow Brealey and Myers (2005). In this case:

$$V = a(1 + x + x^2 + \cdots)$$

where $a = C_1/(1+r)$ and $x = (1+g)/(1+r)$. From above we see that:

$$V = \frac{a}{1-x} = \frac{C_1 \big/ (1+r)}{1 - (1+g)\big/(1+r)} = \frac{C_1}{r-g}$$

Appendix III: Detailed Results

In this Appendix we present the results of the questions asked in the Dividend section, plus other relevant questions and full segmental breakdowns.

As before, the symbol $\bar{x}$ denotes the mean of a dataset, while $\tilde{x}$ denotes the median. N denotes the size of the dataset. All questions in the survey were optional and some questions were not asked directly, depending on the answers to previous questions. Therefore, the number of responses, N, to different questions varies and is shown for each question.

This was an anonymous survey and to further protect the confidentiality of participants, results are shown on an aggregated basis and the statistics are only displayed if there are at least 5 datapoints in the sub-sample. Sub-samples without five datapoints are marked “<5” and the statistics are shown as “na”.

5.1: Use of Different Distribution Mechanisms by Region, Ratings and Listing

Question: Over the last five years, have you done any of the following?

Question 5.1: Use of Different Distribution Mechanisms by Region, Ratings and Listing						
	Regular dividends	Extraordinary/ special dividends	Share repurchases	Stock or scrip dividends	Split or reverse split	*N*
All	93%	25%	39%	8%	13%	205
Region						
Asia excluding Japan	90%	33%	30%	33%	7%	30
Australia & New Zealand	100%	40%	20%	0%	20%	5
Eastern Europe, Middle East and Germany	na	na	na	na	na	<5
Germany	95%	33%	25%	3%	15%	40
Japan	100%	32%	56%	4%	4%	25
Latin America	100%	44%	11%	0%	0%	9
North America	90%	0%	85%	0%	25%	20
Western Europe excluding Germany	90%	18%	35%	4%	15%	71
Undisclosed	na	na	na	na	na	<5
Ratings						
Investment Grade	97%	17%	50%	1%	9%	76
Non-investment Grade	84%	11%	37%	11%	21%	19
Not Rated	na	na	na	na	na	<5
Undisclosed	92%	34%	31%	10%	13%	106
Listing						
Listed	95%	19%	48%	9%	15%	151
Not Listed	88%	42%	12%	4%	6%	52
Undisclosed	na	na	na	na	na	<5

5.1: Use of Different Distribution Mechanisms by Industry

Question: Over the last five years, have you done any of the following?

Results of Question 5.1: Use of Different Distribution Mechanisms by Industry

	Regular dividends	Extraordinary/ special dividends	Share repurchases	Stock or scrip dividends	Split or reverse split	*N*
All	93%	25%	39%	8%	13%	205
Industry						
Automobiles	100%	29%	43%	0%	0%	7
Business Services	na	na	na	na	na	<5
Chemicals	100%	38%	38%	8%	8%	13
Consumer	91%	32%	32%	6%	12%	34
Consumer Finance	100%	57%	43%	14%	14%	7
Diversified & Conglomerates	83%	83%	50%	33%	17%	6
Health Care & Pharmaceuticals	90%	20%	60%	0%	30%	10
Industrials and Materials	97%	14%	43%	5%	16%	37
Media	100%	50%	50%	0%	13%	8
Metals & Mining	100%	25%	13%	0%	0%	8
Oil & Gas	100%	18%	27%	0%	0%	11
Technology	67%	7%	53%	13%	33%	15
Telecommunications	80%	60%	40%	40%	0%	5
Transportation Services	87%	13%	33%	7%	13%	15
Utilities	100%	27%	18%	0%	0%	11
Undisclosed & Other	100%	7%	43%	21%	14%	14

5.2: Proportion of Cash Distributed by Different Distribution Mechanisms

Question: What proportion of the cash paid to shareholders over the last five years was distributed via:

Results of Question 5.2: Proportion of Cash Distributed by Different Distribution Mechanisms													
	1% - 10%	11% - 20%	21% - 30%	31% - 40%	41% - 50%	51% - 60%	61% - 70%	71% - 80%	81% - 90%	91% - 100%	$\bar{x}$	$\tilde{x}$	N
Regular dividends	15%	4%	8%	9%	11%	4%	4%	6%	4%	36%	57.9%	55.0%	161
Extraordinary or special dividends	42%	21%	13%	5%	8%	5%	0%	0%	0%	5%	21.8%	15.0%	38
Share repurchases	23%	11%	10%	10%	11%	11%	8%	3%	2%	10%	38.8%	35.0%	61

5.2: Proportion of Cash Distributed by Different Distribution Mechanisms by Region

Question: What proportion of the cash paid to shareholders over the last five years was distributed via:

Results of Question 5.2: Proportion of Cash Distributed by Different Distribution Mechanisms by Region

	All			Asia excluding Japan			Australia & New Zealand			Eastern Europe, Middle East & Africa			Germany			Japan			Latin America			North America			Western Europe excluding Germany			Undisclosed		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
Regular dividends	57.9	55.0	161	53.2	45.0	22	69.0	65.0	5	na	na	<5	71.1	90.0	28	0.3	0.3	21	63.8	70.0	8	0.5	0.6	16	62.9	75.0	56	na	na	<5
Extraordinary or special dividends	21.8	15.0	38	21.3	15.0	8	na	na	<5	na	na	<5	18.6	15.0	11	na	na	<5	na	na	<5	na	na	<5	21.7	25.0	9	na	na	<5
Share repurchases	38.8	35.0	61	25.0	15.0	5	na	na	<5	na	na	<5	32.1	45.0	7	0.2	0.2	11	na	na	<5	56.9	55.0	16	38.7	35.0	19	na	na	<5

Means and Medians in Percent

5.2: Proportion of Cash Distributed by Different Distribution Mechanisms by Industry

Question: What proprtion of the cash paid to shareholders over the last five years was distributed via:

Results of Question 5.2: Proportion of Cash Distributed by Different Distribution Mechanisms by Industry

	All			Automobiles			Business Services			Chemicals			Consumer			Consumer Finance			Diversified/Conglomerates			Health Care & Pharmaceuticals			Industrials and Materials			Media			Metals and Mining			Oil and Gas			Technology			Telecommunications			Transportation Services			Utilities			Undisclosed & Other		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
Regular dividends	57.9	55.0	161	60.0	70.0	6	na	na	<5	64.1	75.0	11	58.6	65.0	28	na	na	<5	na	na	<5	43.8	35.0	8	62.4	75.0	31	45.0	45.0	7	53.6	45.0	7	63.0	85.0	10	66.3	80.0	8	na	na	<5	60.0	60.0	10	60.0	50.0	10	62.0	60.0	10
Extraordinary or special dividends	21.8	15.0	38	na	na	<5	na	na	<5	na	na	<5	30.0	20.0	10	na	na	<5	23.0	15.0	5	0.0	0.0	<5	0.0	0.0	<5	na	na	<5	na	na	<5	na	na	<5	na	na	<5	na	na	<5	na	na	<5	na	na	<5	na	na	<5
Share repurchases	38.8	35.0	61	na	na	<5	na	na	<5	na	na	<5	42.1	25.0	7	na	na	<5	na	na	<5	58.3	65.0	6	29.2	15.0	12	na	na	<5	na	na	<5	na	na	<5	41.7	40.0	6	na	na	<5	na	na	<5	na	na	<5	na	na	<5

Means and Medians in Percent

5.2: Proportion of Cash Distributed by Different Distribution Mechanisms by Ratings and Listing

Question: What proportion of the cash paid to shareholders over the last five years was distributed via:

Question 5.2: Proportion of Cash Distributed by Different Distribution Mechanisms by Ratings and Listing

	All			Ratings											Listing								
				Investment Grade			Non-investment Grade			Not Rated			Undisclosed			Listed			Not Listed			Undisclosed		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
Regular dividends	57.9	55.0	161	58.2	55.0	63	37.7	15.0	15	na	na	<5	61.3	75.0	80	58.6	60.0	122	57.1	60.0	38	na	na	<5
Extraordinary or special dividends	21.8	15.0	38	13.0	5.0	10	na	na	<5	na	na	<5	26.6	15.0	25	22.6	15.0	21	21.9	15.0	16	na	na	<5
Share repurchases	38.8	35.0	61	44.4	45.0	32	46.7	40.0	6	na	na	<5	29.5	20.0	22	38.7	35.0	57	na	na	<5	na	na	<5

Means and Medians in Percent

5.3: Factors Affecting Distribution Choice

Question: How important are the following factors in your choice between paying Regular dividends, paying Special Dividends and Repurchasing Shares?

Results of Question 5.3: Factors Affecting Distribution Choice									
	Not Important 0	1	2	3	4	Very Important 5	$\bar{x}$	$\tilde{x}$	N
Tax efficiency of the alternatives	20%	17%	10%	22%	20%	12%	2.4	3.0	156
Accounting implications e.g., EPS impact	22%	10%	10%	29%	21%	8%	2.4	3.0	154
Signalling	15%	12%	9%	25%	27%	12%	2.7	3.0	152
Flexibility in changing level of distribution	18%	7%	16%	24%	21%	15%	2.7	3.0	151
Attractiveness to different investors	21%	15%	11%	22%	23%	7%	2.3	3.0	149

5.3: Factors Affecting Distribution Choice by Region

Question: How important are the following factors in your choice between paying Regular Dividends, paying Special Dividends and Repurchasing Shares?

Results of Question 5.3: Factors Affecting Distribution Choice by Region

	All			Asia excluding Japan			Australia & New Zealand			Eastern Europe, Middle East & Africa			Germany			Japan			Latin America			North America			Western Europe excluding Germany			Undisclosed		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
Tax efficiency of the alternatives	2.4	3.0	156	3.2	3.0	25	na	na	<5	na	na	<5	1.9	1.5	26	1.6	1.5	20	1.8	1.0	8	3.0	3.0	19	2.5	3.0	49	na	na	<5
Accounting implications e.g., EPS impact	2.4	3.0	154	3.0	3.0	25	na	na	<5	na	na	<5	1.5	1.0	25	2.8	3.0	19	1.6	1.5	8	3.5	4.0	19	2.1	3.0	49	na	na	<5
Signalling	2.7	3.0	152	3.3	4.0	24	na	na	<5	na	na	<5	1.9	1.0	25	2.2	3.0	19	2.8	3.0	8	4.0	4.0	19	2.5	3.0	48	na	na	<5
Flexibility in changing level of distribution	2.7	3.0	151	3.0	3.0	24	na	na	<5	na	na	<5	1.7	1.0	25	2.8	3.0	20	2.3	2.0	7	4.1	4.0	19	2.4	3.0	47	na	na	<5
Attractiveness to different investors	2.3	3.0	149	3.6	4.0	23	na	na	<5	na	na	<5	1.4	1.0	24	2.8	3.0	20	1.3	0.5	8	3.2	3.0	19	1.9	1.5	46	na	na	<5

Means and Medians in Percent

5.3: Factors Affecting Distribution Choice by Industry

Question: How important are the following factors in your choice between paying Regular Dividends, paying Special Dividendsand Repurchasing Shares?

Results of Question 5.3: Factors Affecting Distribution Choice by Industry

	All			Automobiles			Business Services			Chemicals			Consumer			Consumer Finance			Diversified/Conglomerates			Health Care & Pharmaceuticals			Industrials and Materials			Media			Metals and Mining			Oil and Gas			Technology			Telecommunications			Transportation Services			Utilities			Undisclosed & Other		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
Tax efficiency of the alternatives	2.4	3.0	156	1.4	1.0	5	na	na	<5	1.8	1.5	10	2.2	2.5	26	na	na	<5	3.2	4.0	5	1.5	1.0	10	2.5	2.0	31	3.3	4.0	7	3.2	3.5	6	3.1	3.0	10	2.9	3.0	9	na	na	<5	2.7	3.0	10	2.0	2.0	8	1.7	1.5	10
Accounting implications e.g., EPS impact	2.4	3.0	154	1.6	1.0	5	na	na	<5	2.5	3.0	10	2.2	2.0	25	na	na	<5	2.2	3.0	5	2.6	3.0	10	2.6	3.0	30	1.6	1.0	7	2.8	3.5	6	2.6	3.0	10	3.2	3.0	9	na	na	<5	2.5	2.5	10	2.4	3.0	8	1.4	0.5	10
Signalling	2.7	3.0	152	2.6	4.0	5	na	na	<5	3.0	3.0	10	2.5	3.0	26	na	na	<5	3.0	3.0	5	2.3	3.0	9	2.7	3.0	29	2.3	3.0	7	2.7	3.0	6	2.9	3.0	10	3.2	4.0	9	na	na	<5	3.1	3.0	9	2.8	3.0	8	2.3	2.5	10
Flexibility in changing level of distribution	2.7	3.0	151	2.0	1.0	5	na	na	<5	3.1	3.0	9	2.9	3.0	26	na	na	<5	1.4	0.0	5	2.5	3.0	10	2.4	3.0	28	2.1	2.0	7	2.7	3.0	6	3.0	3.0	10	3.7	5.0	9	na	na	<5	3.1	3.0	9	1.9	2.0	8	2.2	2.0	10
Attractiveness to different investors	2.3	3.0	149	2.0	1.0	5	na	na	<5	2.0	2.0	9	1.6	1.0	26	na	na	<5	na	na	<5	2.6	3.0	9	2.4	3.0	28	1.9	1.0	7	2.7	3.0	6	2.6	3.0	10	3.2	3.0	9	na	na	<5	2.4	3.0	9	2.4	2.5	8	2.6	3.0	10

Means and Medians in Percent

5.3: Factors Affecting Distribution Choice by Ratings and Listing

Question: How important are the following factors in your choice between paying regular Dividends, paying Special Dividends and Repurchasing Shares?

Results of Question 5.3: Factors Affecting Distribution Choice by Ratings and Listing

	All			Ratings												Listing								
				Investment Grade			Non-investment Grade			Not Rated			Undisclosed			Listed			Not Listed			Undisclosed		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
Tax efficiency of the alternatives	2.4	3.0	156	2.3	2.5	62	2.4	2.0	16	na	na	<5	2.5	3.0	76	2.4	3.0	121	2.3	2.5	34	na	na	<5
Accounting implications e.g., EPS impact	2.4	3.0	154	2.6	3.0	61	3.1	3.0	16	na	na	<5	2.1	2.0	75	2.8	3.0	120	1.1	0.0	33	na	na	<5
Signalling	2.7	3.0	152	3.2	4.0	61	3.4	4.0	16	na	na	<5	2.2	2.0	73	3.2	3.0	118	0.9	1.0	33	na	na	<5
Flexibility in changing level of distribution	2.7	3.0	151	3.1	3.0	61	2.9	3.0	16	na	na	<5	2.2	2.5	72	3.1	3.0	118	1.2	0.0	32	na	na	<5
Attractiveness to different investors	2.3	3.0	149	2.5	3.0	61	3.0	3.5	16	na	na	<5	2.0	2.0	70	2.7	3.0	116	0.9	0.0	32	na	na	<5

Means and Medians in Percent

5.4: Dividend Payout Ratio by Region, Ratings and Listing

Question: What has been your average Dividend Payout Ratio over the last five years?

Results of Question 5.4: Dividend Payout Ratio by Region, Ratings and Listing															
Range offered	0	1% - 10%	11% - 20%	21% - 30%	31% - 40%	41% - 50%	51% - 60%	61% - 70%	71% - 80%	81% - 90%	91% - 100%	Over 100%			
Midpoint used for mean & median	*0%*	*5%*	*15%*	*25%*	*35%*	*45%*	*55%*	*65%*	*75%*	*85%*	*95%*	*100%*	$\bar{x}$	$\tilde{x}$	N
All	2%	14%	13%	21%	21%	9%	8%	3%	3%	2%	3%	1%	34%	35%	175
Region															
Asia excluding Japan	0%	12%	19%	23%	19%	12%	4%	8%	0%	0%	0%	4%	32%	25%	26
Australia & New Zealand	0%	0%	0%	20%	20%	0%	20%	20%	0%	0%	20%	0%	55%	55%	5
Eastern Europe, Middle East & Africa	na	na	na	na	na	na	na	na	na	na	na	na	na	na	<5
Germany	0%	17%	3%	11%	31%	6%	11%	3%	8%	3%	8%	0%	42%	35%	36
Japan	0%	26%	22%	22%	13%	9%	4%	0%	4%	0%	0%	0%	24%	25%	23
Latin America	0%	0%	11%	33%	22%	11%	11%	0%	0%	0%	11%	0%	39%	35%	9
North America	13%	6%	31%	13%	25%	6%	6%	0%	0%	0%	0%	0%	23%	20%	16
Western Europe excluding Germany	2%	13%	9%	29%	15%	13%	7%	4%	4%	5%	0%	0%	34%	25%	55
Undisclosed	na	na	na	na	na	na	na	na	na	na	na	na	na	na	<5
Ratings															
Investment Grade	4%	6%	13%	26%	23%	10%	10%	4%	1%	1%	1%	0%	33%	35%	70
Non-investment Grade	0%	21%	21%	29%	7%	14%	0%	0%	7%	0%	0%	0%	26%	25%	14
Not Rated	na	na	na	na	na	na	na	na	na	na	na	na	na	na	<5
Undisclosed	0%	18%	13%	17%	21%	8%	7%	2%	5%	3%	5%	1%	35%	35%	87
Listing															
Listed	2%	8%	14%	23%	20%	11%	9%	5%	4%	2%	1%	1%	35%	35%	132
Not Listed	0%	31%	10%	17%	21%	2%	5%	0%	2%	2%	10%	0%	31%	25%	42
Undisclosed	na	na	na	na	na	na	na	na	na	na	na	na	na	na	<5

5.4: Dividend Payout Ratio by Industry

Question: What has been your average Dividend Payout Ratio over the last five years?

Results of Question 5.4: Dividend Payout Ratio by Industry															
Range offered	0	1% - 10%	11% - 20%	21% - 30%	31% - 40%	41% - 50%	51% - 60%	61% - 70%	71% - 80%	81% - 90%	91% - 100%	Over 100%			
Midpoint used for mean & median	*0%*	*5%*	*15%*	*25%*	*35%*	*45%*	*55%*	*65%*	*75%*	*85%*	*95%*	*100%*	$\bar{x}$	$\tilde{x}$	N
All	2%	14%	13%	21%	21%	9%	8%	3%	3%	2%	3%	1%	34%	35%	175
Industry															
Automobiles	0%	50%	33%	17%	0%	0%	0%	0%	0%	0%	0%	0%	12%	10%	6
Business Services	na	na	na	na	na	na	na	na	na	na	na	na	na	na	<5
Chemicals	0%	8%	15%	23%	31%	0%	15%	8%	0%	0%	0%	0%	33%	35%	13
Consumer	4%	15%	7%	7%	33%	11%	4%	4%	4%	4%	7%	0%	38%	35%	27
Consumer Finance	0%	43%	14%	43%	0%	0%	0%	0%	0%	0%	0%	0%	15%	15%	7
Diversified & Conglomerates	0%	40%	0%	20%	40%	0%	0%	0%	0%	0%	0%	0%	21%	25%	5
Health Care & Pharmaceuticals	0%	13%	13%	38%	0%	13%	13%	13%	0%	0%	0%	0%	33%	25%	8
Industrials and Materials	0%	19%	3%	19%	19%	16%	13%	3%	3%	3%	0%	0%	35%	35%	31
Media	0%	0%	13%	25%	38%	0%	0%	0%	25%	0%	0%	0%	40%	35%	8
Metals & Mining	0%	17%	0%	17%	17%	0%	33%	0%	17%	0%	0%	0%	42%	45%	6
Oil & Gas	10%	10%	30%	20%	10%	10%	0%	0%	0%	0%	10%	0%	28%	20%	10
Technology	10%	10%	60%	10%	0%	10%	0%	0%	0%	0%	0%	0%	17%	15%	10
Telecommunications	na	na	na	na	na	na	na	na	na	na	na	na	na	na	<5
Transportation Services	0%	0%	8%	23%	31%	8%	15%	8%	0%	8%	0%	0%	41%	35%	13
Utilities	0%	0%	8%	23%	31%	8%	15%	8%	0%	8%	0%	0%	41%	35%	13
Undisclosed & Other	0%	0%	8%	15%	31%	8%	0%	15%	0%	8%	8%	8%	51%	35%	13

5.5: Dividend Yield by Region, Ratings and Listing

Question: What has been your average Dividend Payout Yield over the last five years?

Results of Question 5.5: Dividend Yield by Region, Ratings and Listing												
Range offered	0% - 1%	1.1% - 3%	3.1% - 5%	5.1% - 7%	7.1% - 9%	9.1% - 11%	11.1% - 13%	13.1% - 15%	Over 15%			
Midpoint used for mean & median	*0%*	*2%*	*4%*	*6%*	*8%*	*10%*	*12%*	*14%*	*16%*	$\bar{x}$	$\tilde{x}$	N
All	20%	46%	26%	4%	2%	1%	0%	0%	0%	3%	2%	139
Region												
Asia excluding Japan	15%	35%	45%	0%	0%	5%	0%	0%	0%	3%	3%	20
Australia & New Zealand	na	na	na	na	na	na	na	na	na	na	na	<5
Eastern Europe, Middle East & Africa	na	na	na	na	na	na	na	na	na	na	na	<5
Germany	5%	50%	40%	5%	0%	0%	0%	0%	0%	3%	2%	20
Japan	42%	58%	0%	0%	0%	0%	0%	0%	0%	1%	2%	24
Latin America	na	na	na		na	na	na	na	na	na	na	<5
North America	41%	59%	0%	0%	0%	0%	0%	0%	0%	1%	2%	17
Western Europe excluding Germany	13%	43%	33%	9%	2%	0%	0%	0%	0%	3%	2%	46
Undisclosed	na	na	na	na	na	na	na	na	na	na	na	<5
Ratings												
Investment Grade	25%	42%	28%	2%	2%	2%	0%	0%	0%	2%	2%	64
Non-investment Grade	21%	57%	7%	7%	0%	7%	0%	0%	0%	3%	2%	14
Not Rated	na	na	na	na	na	na	na	na	na	na	na	<5
Undisclosed	14%	47%	28%	7%	4%	0%	0%	0%	0%	3%	2%	57
Listing												
Listed	21%	45%	26%	5%	2%	2%	0%	0%	0%	3%	2%	131
Not Listed	17%	50%	33%	0%	0%	0%	0%	0%	0%	2%	2%	6
Undisclosed	na	na	na	na	na	na	na	na	na	na	na	<5

5.5: Dividend Yield by Industry

Question: What has been your average Dividend Payout Yield over the last five years?

Results of Question 5.5: Dividend Yield by Industry												
Range offered	0% - 1%	1.1% - 3%	3.1% - 5%	5.1% - 7%	7.1% - 9%	9.1% - 11%	11.1% - 13%	13.1% - 15%	Over 15%			
Midpoint used for mean & median	*0%*	*2%*	*4%*	*6%*	*8%*	*10%*	*12%*	*14%*	*16%*	$\bar{x}$	$\tilde{x}$	N
All	20%	46%	26%	4%	2%	1%	0%	0%	0%	3%	2%	139
Industry												
Automobiles	na	na	na	na	na	na	na	na	na	na	na	<5
Business Services	na	na	na	na	na	na	na	na	na	na	na	<5
Chemicals	11%	44%	44%	0%	0%	0%	0%	0%	0%	3%	2%	9
Consumer	14%	33%	43%		5%	5%	0%	0%	0%	3%	4%	21
Consumer Finance	80%	20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5
Diversified & Conglomerates	na	na	na	na	na	na	na	na	na	na	na	<5
Health Care & Pharmaceuticals	11%	78%	11%	0%	0%	0%	0%	0%	0%	2%	2%	9
Industrials and Materials	15%	62%	12%	8%	4%	0%	0%	0%	0%	2%	2%	26
Media	60%	0%	20%	20%	0%	0%	0%	0%	0%	2%	0%	5
Metals & Mining	0%	20%	40%	40%	0%	0%	0%	0%	0%	4%	4%	5
Oil & Gas	25%	38%	38%	0%	0%	0%	0%	0%	0%	2%	2%	8
Technology	44%	44%	0%	0%	0%	11%	0%	0%	0%	2%	2%	9
Telecommunications	na	na	na	na	na	na	na	na	na	na	na	<5
Transportation Services	0%	44%	56%	0%	0%	0%	0%	0%	0%	3%	4%	9
Utilities	9%	36%	36%	9%	9%	0%	0%	0%	0%	3%	4%	11
Undisclosed & Other	13%	75%	13%	0%	0%	0%	0%	0%	0%	2%	2%	8

5.6: Targets by Region, Ratings and Listing

Question: For which of the following do you have target ranges and what are those targets?

5.6: Targets by Region, Ratings and Listing					
	Regular Dividend Per Share	Dividend Per Share Growth	Payout Ratio	Dividend Yield	*N*
All	31%	23%	76%	19%	106
Region					
Asia excluding Japan	30%	20%	50%	23%	30
Australia & New Zealand	0%	0%	17%	0%	24
Eastern Europe, Middle East and Germany	0%	0%	9%	0%	22
Germany	6%	6%	46%	9%	35
Japan	30%	3%	17%	3%	30
Latin America	4%	4%	25%	0%	28
North America	4%	18%	25%	11%	28
Western Europe excluding Germany	21%	19%	50%	13%	48
Undisclosed	5%	0%	5%	0%	21
Ratings					
Investment Grade	16%	20%	64%	13%	61
Non-investment Grade	12%	12%	23%	8%	26
Not Rated	9%	5%	9%	5%	22
Undisclosed	32%	14%	60%	16%	57
Listing					
Listed	31%	26%	74%	22%	86
Not Listed	15%	5%	43%	3%	40
Undisclosed	0%	0%	0%	0%	20

5.6: Targets by Region, Ratings and Listing

Question: For which of the following do you have target ranges and what are those targets?

5.6: Targets by Region, Ratings and Listing					
	Regular Dividend Per Share	Dividend Per Share Growth	Payout Ratio	Dividend Yield	*N*
All	31%	23%	76%	19%	106
Industry					
Automobiles	0%	0%	5%	0%	21
Business Services	0%	5%	5%	0%	22
Chemicals	10%	6%	26%	0%	31
Consumer	21%	12%	41%	12%	34
Consumer Finance	4%	0%	9%	0%	23
Diversified & Conglomerates	5%	0%	5%	0%	22
Health Care & Pharmaceuticals	8%	4%	12%	4%	25
Industrials and Materials	22%	22%	42%	8%	36
Media	0%	0%	13%	0%	23
Metals & Mining	0%	0%	10%	10%	20
Oil & Gas	4%	0%	13%	0%	24
Technology	5%	10%	10%	20%	20
Telecommunications	0%	0%	9%	0%	22
Transportation Services	7%	0%	29%	4%	28
Utilities	14%	18%	32%	11%	28
Undisclosed & Other	11%	4%	26%	7%	27

5.7: Dividend Objectives

Question: How important are the following objectives?

Results of Question 5.7: Dividend Objectives									
	Not Important 0	1	2	3	4	Very Important 5	$\bar{x}$	$\tilde{x}$	N
Maintain stable Dividend per Share	15%	10%	10%	18%	27%	21%	3.0	3.0	156
Maintain stable Dividend Payout Ratio	12%	13%	12%	23%	24%	15%	2.8	3.0	156
Maintain stable Dividend Yield	20%	22%	18%	22%	10%	6%	2.0	2.0	143
Increase Dividend per Share	14%	7%	13%	25%	27%	14%	2.9	3.0	157
Increase Dividend Payout Ratio	18%	20%	24%	16%	14%	7%	2.1	2.0	147
Increase Dividend Yield	25%	22%	18%	17%	14%	4%	1.9	2.0	144
Avoid cutting the Dividend per Share	11%	6%	7%	15%	22%	39%	3.5	4.0	153
Set Dividend in line with cashflows	6%	13%	20%	23%	24%	13%	2.9	3.0	135

5.7: Dividend Objectives by Region

Question: How important are the following objectives?

Results of Question 5.7: Dividend Objectives by Region

	All			Asia excluding Japan			Australia & New Zealand			Eastern Europe, Middle East & Africa			Germany			Japan			Latin America			North America			Western Europe excluding Germany			Undisclosed		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
Maintain stable Dividend per Share	3.0	3.0	156	3.7	4.0	22	na	na	<5	na	na	<5	2.9	3.0	30	3.4	4.0	22	1.6	0.5	8	3.0	3.0	15	2.7	3.0	50	na	na	<5
Maintain stable Dividend Payout Ratio	2.8	3.0	156	3.8	4.0	24	2.4	2.0	5	na	na	<5	2.5	3.0	31	2.5	3.0	21	3.0	3.5	8	2.7	3.0	15	2.6	3.0	47	na	na	<5
Maintain stable Dividend Yield	2.0	2.0	143	3.3	3.0	20	na	na	<5	na	na	<5	1.4	1.0	29	1.8	1.0	21	1.3	1.0	8	2.4	2.5	14	1.9	2.0	42	na	na	<5
Increase Dividend per Share	2.9	3.0	157	3.3	3.0	22	na	na	<5	na	na	<5	2.7	3.0	30	3.1	3.5	22	1.6	1.0	9	3.4	4.0	14	2.7	3.0	51	na	na	<5
Increase Dividend Payout Ratio	2.1	2.0	147	2.9	3.0	23	na	na	<5	na	na	<5	1.6	1.5	28	2.6	2.5	22	1.6	1.5	8	1.7	2.0	14	1.8	2.0	44	na	na	<5
Increase Dividend Yield	1.9	2.0	144	3.2	3.5	22	na	na	<5	na	na	<5	1.2	1.0	28	2.4	3.0	22	1.1	1.0	7	1.8	2.0	14	1.5	1.0	43	na	na	<5
Avoid cutting the Dividend per Share	3.5	4.0	153	3.7	4.0	21	na	na	<5	na	na	<5	3.1	4.0	30	3.1	3.0	21	1.9	2.0	8	4.9	5.0	14	3.6	4.0	50	na	na	<5
Set Dividend in line with cashflows	2.9	3.0	135	3.5	4.0	22	na	na	<5	na	na	<5	3.1	3.0	26	2.6	3.0	20	3.2	3.0	5	1.9	1.5	14	2.8	3.0	41	na	na	<5

Means and Medians in Percent

5.7: Dividend Objectives by Industry

Question: How important are the following objectives?

Results of Question 5.7: Dividend Objectives by Industry

	All			Automobiles			Business Services			Chemicals			Consumer			Consumer Finance			Diversified/Conglomerates			Health Care & Pharmaceuticals			Industrials and Materials			Media			Metals and Mining			Oil and Gas			Technology			Telecommunications			Transportation Services			Utilities			Undisclosed & Other		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
Maintain stable Dividend per Share	3.0	3.0	156	na	na	<5	na	na	<5	2.4	3.0	12	na	na	<5	2.8	3.0	24	4.0	4.0	5	3.6	4.0	8	2.7	3.0	31	2.3	2.0	6	4.0	4.0	7	3.4	4.0	8	3.1	3.5	8	na	na	<5	2.7	3.0	12	3.6	4.0	10	2.9	4.0	11
Maintain stable Dividend Payout Ratio	2.8	3.0	156	na	na	<5	na	na	<5	2.4	2.0	13	na	na	<5	2.9	3.0	24	2.6	3.0	5	2.3	3.0	8	2.7	3.0	31	3.0	3.0	7	2.6	3.0	5	2.4	2.5	8	2.2	2.0	9	na	na	<5	3.5	4.0	12	3.2	3.0	9	3.3	4.0	11
Maintain stable Dividend Yield	2.0	2.0	143	na	na	<5	na	na	<5	1.7	2.0	11	na	na	<5	2.0	2.0	23	2.0	1.0	5	2.0	1.5	8	1.8	1.5	28	1.8	2.0	6	1.8	1.0	5	1.8	2.0	8	2.6	3.0	9	na	na	<5	2.4	2.5	10	2.6	2.5	8	2.1	1.5	10
Increase Dividend per Share	2.9	3.0	157	3.4	3.0	5	na	na	<5	3.2	3.5	12	3.4	3.0	5	2.5	2.5	24	3.2	3.0	5	3.3	4.0	9	2.6	3.0	30	3.0	4.0	6	3.3	3.0	7	2.4	2.0	9	2.5	3.0	8	na	na	<5	2.7	3.0	12	3.0	3.0	8	3.0	3.0	11
Increase Dividend Payout Ratio	2.1	2.0	147	1.8	1.0	5	na	na	<5	2.4	2.5	12	na	na	<5	2.0	2.0	22	1.6	1.0	5	2.1	1.5	8	1.8	2.0	29	2.2	2.0	5	1.8	2.0	5	1.8	1.5	8	1.8	1.5	8	na	na	<5	2.4	2.0	11	3.1	3.5	8	2.2	2.0	11
Increase Dividend Yield	1.9	2.0	144	2.0	1.0	5	na	na	<5	1.6	1.0	10	na	na	<5	1.8	1.0	22	1.6	1.0	5	2.3	1.5	8	1.9	2.0	29	1.7	2.0	6	1.4	1.0	5	1.3	1.0	8	2.1	2.0	8	na	na	<5	2.2	2.0	11	2.6	3.0	8	1.4	0.5	10
Avoid cutting the Dividend per Share	3.5	4.0	153	na	na	<5	na	na	<5	3.8	5.0	11	na	na	<5	3.6	4.0	23	3.8	4.0	5	3.8	5.0	8	3.2	4.0	30	3.2	4.0	6	3.7	5.0	7	3.3	4.0	8	3.4	4.0	8	na	na	<5	3.3	3.5	12	4.0	5.0	9	3.5	4.0	11
Set Dividend in line with cashflows	2.9	3.0	135	na	na	<5	na	na	<5	2.1	2.5	10	na	na	<5	3.2	3.0	21	3.0	4.0	5	2.0	2.0	6	2.9	3.0	28	2.5	2.5	6	na	na	<5	2.6	3.0	8	2.9	2.0	7	na	na	<5	3.0	3.0	10	3.2	3.5	6	3.2	3.0	12

Means and Medians in Percent

5.7: Dividend Objectives by Ratings and Listing

Question: How important are the following objectives?

Results of Question 5.7: Dividend Objectives by Ratings and Listing

	All			Ratings												Listing								
				Investment Grade			Non-investment Grade			Not Rated			Undisclosed			Listed			Not Listed			Undisclosed		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
Maintain stable Dividend per Share	3.0	3.0	156	2.9	3.0	65	3.4	4.0	15	na	na	<5	2.9	3.0	72	3.2	4.0	124	2.1	2.0	31	na	na	<5
Maintain stable Dividend Payout Ratio	2.8	3.0	156	2.7	3.0	62	3.2	3.0	15	na	na	<5	2.8	3.0	75	2.9	3.0	121	2.4	2.0	34	na	na	<5
Maintain stable Dividend Yield	2.0	2.0	143	1.9	2.0	56	2.1	2.0	15	na	na	<5	2.0	2.0	69	2.2	2.0	113	1.2	0.0	29	na	na	<5
Increase Dividend per Share	2.9	3.0	157	3.1	3.0	65	2.9	4.0	15	na	na	<5	2.6	3.0	73	3.1	3.0	123	1.8	2.0	33	na	na	<5
Increase Dividend Payout Ratio	2.1	2.0	147	2.0	2.0	56	2.5	3.0	15	na	na	<5	2.0	2.0	72	2.2	2.0	116	1.7	1.0	30	na	na	<5
Increase Dividend Yield	1.9	2.0	144	1.9	2.0	55	2.1	2.0	15	na	na	<5	1.8	2.0	70	2.1	2.0	115	0.8	0.0	28	na	na	<5
Avoid cutting the Dividend per Share	3.5	4.0	153	3.8	4.0	63	3.8	4.0	15	na	na	<5	3.2	4.0	71	3.9	4.0	121	2.0	1.0	31	na	na	<5
Set Dividend in line with cashflows	2.9	3.0	135	2.6	3.0	52	3.3	3.5	14	na	na	<5	2.9	3.0	65	2.9	3.0	106	3.0	3.0	28	na	na	<5

Means and Medians in Percent

5.8: Reaction to Weak Cashflows

Question: Suppose that your operating cashflows were weak and you had insufficient liquid resources to pay Regular Dividends at the most recent level. How likely would you be to take each of these actions?

Results of Question 5.8: Reaction to Weak Cashflows

	Never 0	Slightly Likely 1	2	3	4	Very Likely 5	$\bar{x}$	$\tilde{x}$	N
Borrow up to the limit of the credit rating	26%	22%	11%	15%	20%	6%	2.0	2.0	159
Borrow and allow the credit rating to fall	48%	26%	12%	10%	4%	0%	1.0	1.0	156
Cut deferrable investment	10%	27%	15%	20%	17%	10%	2.4	2.0	157
Cut strategic investment	29%	30%	18%	9%	11%	3%	1.5	1.0	157
Sell assets at their fair value	25%	31%	12%	16%	12%	2%	1.6	1.0	153
Sell assets at a discount to their fair value	59%	23%	12%	4%	2%	0%	0.7	0.0	157
Raise new equity	48%	31%	8%	8%	5%	0%	0.9	1.0	153
Cut dividends	9%	14%	17%	20%	22%	19%	2.9	3.0	162

5.8: Reaction to Weak Cashflows by Region

Question: Suppose that your operating cashflows were weak and you had insufficient liquid resources to pay Regular Dividends at the most recent level. How likely would you be to take each of these actions?

Results of Question 5.8: Reaction to Weak Cashflows by Region

	All			Asia excluding Japan			Australia & New Zealand			Eastern Europe, Middle East & Africa			Germany			Japan			Latin America			North America			Western Europe excluding Germany			Undisclosed		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
Borrow up to the limit of the credit rating	2.0	2.0	159	1.8	1.0	24	na	na	<5	na	na	<5	1.6	1.0	34	1.6	1.0	21	2.6	3.0	9	3.2	4.0	14	2.0	2.0	50	na	na	<5
Borrow and allow the credit rating to fall	1.0	1.0	156	1.1	1.0	24	na	na	<5	na	na	<5	0.7	0.0	34	1.0	1.0	21	0.8	0.0	9	1.8	2.0	13	0.8	0.0	49	na	na	<5
Cut deferrable investment	2.4	2.0	157	2.5	2.5	24	na	na	<5	na	na	<5	1.9	1.0	34	2.3	2.0	21	2.0	1.0	9	3.8	4.0	13	2.3	2.0	50	na	na	<5
Cut strategic investment	1.5	1.0	157	1.7	2.0	24	na	na	<5	na	na	<5	1.2	1.0	34	1.8	2.0	21	0.4	0.0	9	2.5	2.0	13	1.5	1.0	49	na	na	<5
Sell assets at their fair value	1.6	1.0	153	1.7	1.0	24	na	na	<5	na	na	<5	1.3	1.0	32	2.1	2.0	21	1.1	1.0	9	2.7	3.0	13	1.6	1.0	48	na	na	<5
Sell assets at a discount to their fair value	0.7	0.0	157	0.8	0.0	24	na	na	<5	na	na	<5	0.4	0.0	33	1.2	1.0	21	0.4	0.0	9	1.2	1.0	13	0.5	0.0	50	na	na	<5
Raise new equity	0.9	1.0	153	1.3	1.0	24	na	na	<5	na	na	<5	0.7	0.0	32	0.9	1.0	21	0.3	0.0	7	0.8	1.0	13	0.9	1.0	48	na	na	<5
Cut dividends	2.9	3.0	162	3.2	3.0	24	na	na	<5	na	na	<5	3.5	4.0	34	2.1	2.0	21	3.0	4.0	9	2.2	2.0	14	2.8	3.0	53	na	na	<5

Means and Medians in Percent

5.8: Reaction to Weak Cashflows by Industry

Question: Suppose that your operating cashflows were weak and you had insufficient liquid resources to pay Regular Dividends at the most recent level. How likely would you be to take each of these actions?

Results of Question 5.8: Reaction to Weak Cashflows by Industry

	All			Automobiles			Business Services			Chemicals			Consumer			Consumer Finance			Diversified/Conglomerates			Health Care & Pharmaceuticals			Industrials and Materials			Media			Metals and Mining			Oil and Gas			Technology			Telecommunications			Transportation Services			Utilities			Undisclosed & Other		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
Borrow up to the limit of the credit rating	2.0	2.0	159	1.2	0.5	6	na	na	<5	2.7	2.5	10	2.0	1.5	26	na	na	<5	na	na	<5	2.1	2.0	9	2.1	2.5	28	2.4	3.0	7	1.0	1.0	7	2.9	3.5	10	2.1	2.0	8	na	na	<5	1.5	1.0	13	1.8	1.0	8	1.6	1.0	13
Borrow and allow the credit rating to fall	1.0	1.0	156	0.0	0.0	6	na	na	<5	1.1	0.5	10	1.1	1.0	25	na	na	<5	na	na	<5	1.2	1.0	9	1.0	0.5	28	1.3	1.0	7	0.8	0.5	6	1.0	0.5	10	1.3	1.0	8	na	na	<5	0.3	0.0	12	1.0	0.5	8	0.7	0.0	13
Cut deferrable investment	2.4	2.0	157	1.3	1.0	6	na	na	<5	3.0	3.5	10	2.1	2.0	25	na	na	<5	1.4	1.0	5	2.7	2.0	9	2.9	3.0	28	2.5	2.5	6	1.7	1.0	6	1.8	1.0	10	2.5	2.5	8	na	na	<5	2.0	1.5	12	2.4	2.5	8	2.8	3.0	13
Cut strategic investment	1.5	1.0	157	0.8	1.0	6	na	na	<5	1.9	1.5	10	1.4	1.0	25	na	na	<5	0.8	1.0	5	2.0	2.0	9	2.0	2.0	28	1.3	1.0	6	1.4	1.0	7	0.8	0.0	9	1.6	1.0	8	na	na	<5	1.4	1.0	12	1.1	1.0	8	1.6	1.0	13
Sell assets at their fair value	1.6	1.0	153	1.8	2.0	6	na	na	<5	1.0	1.0	9	2.2	2.0	24	na	na	<5	1.0	1.0	5	2.0	1.5	8	1.9	1.5	28	1.6	1.0	5	1.0	1.0	7	1.2	1.0	10	2.0	1.0	8	na	na	<5	1.5	1.0	11	1.5	1.5	8	1.5	1.0	13
Sell assets at a discount to their fair value	0.7	0.0	157	0.3	0.0	6	na	na	<5	0.3	0.0	10	0.9	1.0	25	na	na	<5	0.0	0.0	5	1.0	1.0	9	0.9	0.5	28	0.3	0.0	6	0.6	0.0	7	0.6	0.0	10	1.0	1.0	8	na	na	<5	0.4	0.0	11	0.5	0.0	8	0.5	0.0	13
Raise new equity	0.9	1.0	153	0.3	0.0	6	na	na	<5	0.2	0.0	10	1.2	1.0	26	na	na	<5	0.2	0.0	5	1.0	1.0	9	1.1	1.0	27	0.3	0.0	6	0.6	0.0	7	0.6	0.0	8	2.0	2.0	8	na	na	<5	0.8	1.0	10	1.4	1.0	8	0.8	0.5	12
Cut dividends	2.9	3.0	162	3.2	4.0	6	na	na	<5	2.1	2.0	10	3.5	4.0	26	na	na	<5	3.4	3.0	5	2.7	3.0	9	3.0	3.5	28	2.3	2.0	6	3.0	3.0	7	2.9	3.0	10	3.1	3.5	8	na	na	<5	2.7	3.0	13	3.5	4.5	10	2.5	3.0	13

Means and Medians in Percent

5.8: Reaction to Weak Cashflows by Ratings and Listing

Question: Suppose that your operating cashflows were weak and you had insufficient liquid resources to pay Regular Dividends at the most recent level. How likely would you be to take each of these actions?

Results of Question 5.8: Reaction to Weak Cashflows by Ratings and Listing

	All			Ratings												Listing								
				Investment Grade			Non-investment Grade			Not Rated			Undisclosed			Listed			Not Listed			Undisclosed		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
Borrow up to the limit of the credit rating	2.0	2.0	159	2.4	2.0	64	2.9	3.0	15	na	na	<5	1.6	1.0	76	2.2	2.0	120	1.4	1.0	39	na	na	<5
Borrow and allow the credit rating to fall	1.0	1.0	156	1.1	1.0	64	1.5	1.0	15	na	na	<5	0.7	0.0	73	1.1	1.0	117	0.5	0.0	39	na	na	<5
Cut deferrable investment	2.4	2.0	157	2.7	3.0	64	2.7	3.0	15	na	na	<5	2.0	2.0	74	2.6	3.0	119	1.7	1.0	38	na	na	<5
Cut strategic investment	1.5	1.0	157	1.5	1.0	64	2.2	3.0	15	na	na	<5	1.4	1.0	74	1.7	1.0	119	0.9	1.0	38	na	na	<5
Sell assets at their fair value	1.6	1.0	153	1.9	2.0	61	2.1	2.0	15	na	na	<5	1.3	1.0	73	1.9	1.5	116	0.9	1.0	37	na	na	<5
Sell assets at a discount to their fair value	0.7	0.0	157	0.7	0.0	63	1.3	1.0	15	na	na	<5	0.5	0.0	75	0.8	0.0	119	0.3	0.0	38	na	na	<5
Raise new equity	0.9	1.0	153	0.7	0.0	60	1.5	1.0	15	na	na	<5	1.0	1.0	74	1.0	1.0	117	0.8	0.0	36	na	na	<5
Cut dividends	2.9	3.0	162	2.4	2.0	67	3.6	4.0	15	na	na	<5	3.2	3.0	76	2.8	3.0	124	3.2	3.5	38	na	na	<5

Means and Medians in Percent

5.9: Reasons for Special Dividend by Region, Ratings and Listing

Question: Why did you pay the Special or Extraordinary Dividend?

5.9: Reasons for Special Dividend by Region, Ratings and Listing

	Excessive cash holdings	Major company restructuring	Policy of issuing special dividends whenever it has excessive resources	Signal company quality to the market	*N*
All	77%	10%	23%	17%	30
Region					
Asia excluding Japan	na	na	na	na	<5
Australia & New Zealand	na	na	na	na	<5
Eastern Europe, Middle East and Germany	na	na	na	na	<5
Germany	86%	14%	14%	29%	7
Japan	na	na	na	na	<5
Latin America	na	na	na	na	<5
North America	na	na	na	na	<5
Western Europe excluding Germany	67%	11%	33%	0%	9
Undisclosed	na	na	na	na	<5
Ratings					
Investment Grade	60%	20%	0%	40%	5
Non-investment Grade	na	na	na	na	<5
Not Rated	na	na	na	na	<5
Undisclosed	82%	9%	32%	9%	22
Listing					
Listed	80%	7%	0%	33%	15
Not Listed	73%	13%	47%	0%	15
Undisclosed	na	na	na	na	<5

5.9: Reasons for Special Dividend by Industry

Question: Why did you pay the Special or Extraordinary Dividend?

Results of Question 5.9: Reasons for Special Dividend by Industry

	Excessive cash holdings	Major company restructuring	Policy of issuing special dividends whenever it has excessive resources	Signal company quality to the market	*N*
All	77%	10%	23%	17%	30
Industry					
Automobiles	na	na	na	na	<5
Business Services	na	na	na	na	<5
Chemicals	na	na	na	na	<5
Consumer	63%	25%	13%	0%	8
Consumer Finance	na	na	na	na	<5
Diversified & Conglomerates	na	na	na	na	<5
Health Care & Pharmaceuticals	na	na	na	na	<5
Industrials and Materials	na	na	na	na	<5
Media	na	na	na	na	<5
Metals and Mining	na	na	na	na	<5
Oil and Gas	na	na	na	na	<5
Technology	na	na	na	na	<5
Telecommunications	na	na	na	na	<5
Transportation Services	na	na	na	na	<5
Utilities	na	na	na	na	<5
Undisclosed & Other	na	na	na	na	<5

5.10: Net Share Repurchases

Question: What proportion of your shares has your company repurchased (net of issuance) over the last five years?

Results of Question 5.10												
	0% - 1%	1.1% - 3%	3.1% - 5%	5.1% -7%	7.1% - 9%	9.1% - 11%	11.1% - 13%	13.1% - 15%	Over 15%	$\bar{x}$	$\tilde{x}$	*N*
% of Net Shares Repurchased	13%	13%	20%	9%	2%	20%	7%	4%	13%	7.2%	6.0%	46
% of Net Shares Issued	21%	31%	17%	3%	7%	3%	3%	3%	10%	5.1%	2.0%	29

5.10: Net Share Repurchases by Region

Question: What proportion of your shares has your company repurchased (net of issuance) over the last five years?

Results of Question 5.10: Net Share Repurchases by Region

	All			Asia excluding Japan			Australia & New Zealand			Eastern Europe, Middle East & Africa			Germany			Japan			Latin America			North America			Western Europe excluding Germany			Undisclosed		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
% of Net Shares Repurchased	7.2	6.0	46	na	na	<5	na	na	<5	na	na	<5	na	na	<5	na	na	<5	na	na	<5	7.7	6.0	13	7.1	6.0	19	na	na	<5
% of Net Shares Issued	5.1	2.0	29	na	na	<5	na	na	<5	na	na	<5	4.3	4.0	6	4.1	2.0	11	na	na	<5	na	na	<5	na	na	<5	na	na	<5

Means and Medians in Percent

5.10: Net Share Repurchases by Industry

Question: What proportion of your shares has your company repurchased (net of issuance) over the last five years?

Results of Question 5.10: Net Share Repurchases by Industry

	All			Automobiles			Business Services			Chemicals			Consumer			Consumer Finance			Diversified/Conglomerates			Health Care & Pharmaceuticals			Industrials and Materials			Media			Metals and Mining			Oil and Gas			Technology			Telecommunications			Transportation Services			Utilities			Undisclosed & Other		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
% of Net Shares Repurchased	7.2	6.0	46	na	na	<5	na	na	<5	na	na	<5	5.8	3.0	10	na	na	<5	na	na	<5	na	na	<5	5.8	5.0	6	na	na	<5	na	na	<5	na	na	<5	7.8	300.0	6	na	na	<5	na	na	<5	na	na	<5	na	na	<5
% of Net Shares Issued	5.1	2.0	29	na	na	<5	na	na	<5	na	na	<5	na	na	<5	na	na	<5	na	na	<5	na	na	<5	4.3	3.0	8	na	na	<5	na	na	<5	na	na	<5	na	na	<5	na	na	<5	na	na	<5	na	na	<5

Means and Medians in Percent

5.10: Net Share Repurchases by Ratings and Listing

Question: What proportion of your shares has your company repurchased (net of issuance) over the last five years?

Results of Question 5.10: Net Share Repurchases by Ratings and Listing

	All			Ratings												Listing								
				Investment Grade			Non-investment Grade			Not Rated			Undisclosed			Listed			Not Listed			Undisclosed		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
% of Net Shares Repurchased	7.2	6.0	46	8.0	10.0	23	na	na	<5	na	na	<5	6.3	4.0	19	6.8	6.0	41	10.5	10.0	5	na	na	<5
% of Net Shares Issued	5.1	2.0	29	4.0	2.0	15	na	na	<5	na	na	<5	4.4	2.0	10	5.2	3.0	28	na	na	<5	na	na	<5

Means and Medians in Percent

5.11: Factors Affecting Decision to Repurchase Shares

Question: How important were the following factors in your decision to repurchase shares?

Results of Question 5.11: Factors Affecting Decision to Repurchase Shares									
	Not Important 0	1	2	3	4	Very Important 5	$\bar{x}$	$\tilde{x}$	N
Increase the leverage of the Company	26%	13%	14%	14%	22%	10%	2.2	2.0	69
Concentrate equity holdings	50%	18%	16%	7%	1%	7%	1.1	0.5	68
Exploit temporary mispricing	23%	27%	10%	13%	23%	4%	2.0	1.5	70
Exploit persistent mispricing	31%	28%	9%	18%	9%	4%	1.6	1.0	67
Mitigate dilution from employee schemes	29%	16%	13%	19%	12%	12%	2.0	2.0	69
Return excess capital to shareholders	18%	7%	8%	21%	21%	25%	2.9	3.0	72
Tax efficient distribution	21%	16%	17%	23%	13%	10%	2.2	2.0	70
Increase EPS	19%	12%	16%	26%	18%	9%	2.4	3.0	68
Manage EPS volatility	39%	28%	16%	10%	4%	1%	1.2	1.0	67
Reduce the amount of capital	49%	22%	12%	10%	3%	3%	1.0	1.0	67

Means and Medians in Percent

5.11: Factors Affecting Decision to Repurchase Shares by Region

Question: How important were the following factors in your decision to repurchase shares?

Results of Question 5.11: Factors Affecting Decision to Repurchase Shares by Region

	All			Asia excluding Japan			Australia & New Zealand			Eastern Europe, Middle East & Africa			Germany			Japan			Latin America			North America			Western Europe excluding Germany			Undisclosed		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
Increase the leverage of the Company	2.2	2.0	69	3.0	3.5	8	na	na	<5	na	na	<5	1.7	1.5	10	2.4	3.0	11	na	na	<5	1.8	2.0	14	2.3	2.0	21	na	na	<5
Concentrate equity holdings	1.1	0.5	68	3.0	2.5	8	na	na	<5	na	na	<5	0.6	0.0	10	1.5	1.0	11	na	na	<5	0.9	0.5	14	0.8	0.0	21	na	na	<5
Exploit temporary mispricing	2.0	1.5	70	3.4	4.0	8	na	na	<5	na	na	<5	1.1	1.0	10	2.0	2.0	11	na	na	<5	2.2	2.0	14	1.6	1.0	22	na	na	<5
Exploit persistent mispricing	1.6	1.0	67	3.4	4.0	8	na	na	<5	na	na	<5	0.8	0.0	9	1.5	1.0	11	na	na	<5	1.8	1.0	15	1.2	1.0	20	na	na	<5
Mitigate dilution from employee schemes	2.0	2.0	69	2.1	2.0	8	na	na	<5	na	na	<5	1.5	0.0	10	2.4	3.0	11	na	na	<5	3.0	3.5	14	1.3	1.0	22	na	na	<5
Return excess capital to shareholders	2.9	3.0	72	3.3	4.0	9	na	na	<5	na	na	<5	1.8	1.5	10	2.9	3.0	13	na	na	<5	3.9	4.0	14	2.8	3.0	21	na	na	<5
Tax efficient distribution	2.2	2.0	70	2.4	2.5	8	na	na	<5	na	na	<5	1.4	1.0	10	1.3	1.5	12	na	na	<5	3.6	3.5	14	2.1	2.0	21	na	na	<5
Increase EPS	2.4	3.0	68	3.3	3.0	8	na	na	<5	na	na	<5	1.4	1.0	10	2.3	3.0	11	na	na	<5	3.2	3.0	15	2.2	2.5	20	na	na	<5
Manage EPS volatility	1.2	1.0	67	2.4	2.0	8	na	na	<5	na	na	<5	0.2	0.0	10	1.6	2.0	11	na	na	<5	1.4	1.0	14	0.9	1.0	20	na	na	<5
Reduce the amount of capital	1.0	1.0	67	2.0	2.0	8	na	na	<5	na	na	<5	0.2	0.0	10	1.5	1.0	11	na	na	<5	0.6	0.0	14	0.9	0.5	20	na	na	<5

Means and Medians in Percent

5.11: Factors Affecting Decision to Repurchase Shares by Industry

Question: How important were the following factors in your decision to repurchase shares?

Results of Question 5.11: Factors Affecting Decision to Repurchase Shares by Industry

	All			Automobiles			Business Services			Chemicals			Consumer			Consumer Finance			Diversified/Conglomerates			Health Care & Pharmaceuticals			Industrials and Materials			Media			Metals and Mining			Oil and Gas			Technology			Telecommunications			Transportation Services			Utilities			Undisclosed & Other		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
Increase the leverage of the Company	2.2	2.0	69	na	na	<5	na	na	<5	2.2	1.0	5	2.4	3.0	10	na	na	<5	na	na	<5	2.2	2.0	6	2.5	3.0	13	na	na	<5	na	na	<5	na	na	<5	1.4	0.5	8	na	na	<5	2.2	2.0	5	na	na	<5	na	na	<5
Concentrate equity holdings	1.1	0.5	68	na	na	<5	na	na	<5	0.4	0.0	5	1.2	1.0	9	na	na	<5	na	na	<5	1.0	1.0	6	0.9	0.0	14	na	na	<5	na	na	<5	na	na	<5	1.8	1.0	8	na	na	<5	1.0	0.0	5	na	na	<5	na	na	<5
Exploit temporary mispricing	2.0	1.5	70	na	na	<5	na	na	<5	1.0	1.0	5	2.3	2.0	9	na	na	<5	na	na	<5	3.0	3.5	6	1.9	2.0	14	na	na	<5	na	na	<5	na	na	<5	2.0	1.0	8	na	na	<5	1.6	1.0	5	na	na	<5	na	na	<5
Exploit persistent mispricing	1.6	1.0	67	na	na	<5	na	na	<5	1.6	1.0	5	1.8	1.0	10	na	na	<5	na	na	<5	2.3	2.5	6	1.3	1.0	13	na	na	<5	na	na	<5	na	na	<5	1.9	1.0	7	na	na	<5	1.0	1.0	5	na	na	<5	na	na	<5
Mitigate dilution from employee schemes	2.0	2.0	69	na	na	<5	na	na	<5	na	na	<5	1.3	1.0	10	na	na	<5	na	na	<5	2.8	3.0	6	2.1	2.0	14	na	na	<5	na	na	<5	na	na	<5	3.4	3.5	8	na	na	<5	1.4	0.0	5	na	na	<5	na	na	<5
Return excess capital to shareholders	2.9	3.0	72	na	na	<5	na	na	<5	4.4	5.0	5	1.6	1.0	9	na	na	<5	na	na	<5	2.5	2.5	6	2.8	3.0	14	na	na	<5	na	na	<5	na	na	<5	3.8	4.5	8	na	na	<5	3.0	4.0	5	na	na	<5	3.4	4.0	5
Tax efficient distribution	2.2	2.0	70	na	na	<5	na	na	<5	2.4	3.0	5	0.9	0.0	9	na	na	<5	na	na	<5	2.0	2.0	6	1.9	1.5	14	na	na	<5	na	na	<5	na	na	<5	2.6	2.5	8	na	na	<5	2.8	3.0	5	na	na	<5	na	na	<5
Increase EPS	2.4	3.0	68	na	na	<5	na	na	<5	3.0	3.0	5	2.2	2.0	10	na	na	<5	na	na	<5	2.5	2.5	6	2.8	3.0	13	na	na	<5	na	na	<5	na	na	<5	2.4	3.0	8	na	na	<5	2.8	3.0	5	na	na	<5	na	na	<5
Manage EPS volatility	1.2	1.0	67	na	na	<5	na	na	<5	0.6	0.0	5	0.6	0.0	9	na	na	<5	na	na	<5	1.2	1.0	6	1.3	1.0	13	na	na	<5	na	na	<5	na	na	<5	1.8	1.5	8	na	na	<5	2.4	3.0	5	na	na	<5	na	na	<5
Reduce the amount of capital	1.0	1.0	67	na	na	<5	na	na	<5	1.2	0.0	5	0.8	0.0	8	na	na	<5	na	na	<5	0.7	1.0	6	1.0	0.0	13	na	na	<5	na	na	<5	na	na	<5	1.0	0.0	8	na	na	<5	1.8	1.0	5	na	na	<5	na	na	<5

Means and Medians in Percent

5.11: Factors Affecting Decision to Repurchase Shares by Ratings and Listing

Question: How important were the following factors in your decision to repurchase shares?

Results of Question 5.11: Factors Affecting Decision to Repurchase Shares by Ratings and Listing

	All			Ratings												Listing								
				Investment Grade			Non-investment Grade			Not Rated			Undisclosed			Listed			Not Listed			Undisclosed		
	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N	$\bar{x}$	$\tilde{x}$	N
Increase the leverage of the Company	2.2	2.0	69	1.9	2.0	34	3.6	4.0	5	na	na	<5	2.3	2.0	28	2.3	2.0	64	na	na	<5	na	na	<5
Concentrate equity holdings	1.1	0.5	68	0.9	0.0	34	2.4	2.0	5	na	na	<5	1.1	0.0	27	1.0	0.0	63	na	na	<5	na	na	<5
Exploit temporary mispricing	2.0	1.5	70	1.5	1.0	34	3.8	4.0	5	na	na	<5	2.1	2.0	29	2.0	2.0	65	na	na	<5	na	na	<5
Exploit persistent mispricing	1.6	1.0	67	1.2	1.0	35	2.8	3.0	5	na	na	<5	1.7	1.0	25	1.6	1.0	62	na	na	<5	na	na	<5
Mitigate dilution from employee schemes	2.0	2.0	69	2.0	2.0	34	2.3	2.0	6	na	na	<5	1.9	2.0	27	2.1	2.0	65	na	na	<5	na	na	<5
Return excess capital to shareholders	2.9	3.0	72	3.4	4.0	35	4.2	4.0	5	na	na	<5	2.2	2.5	30	3.0	3.0	66	1.6	1.0	5	na	na	<5
Tax efficient distribution	2.2	2.0	70	2.7	3.0	35	3.0	3.0	5	na	na	<5	1.5	1.0	28	2.3	2.0	65	na	na	<5	na	na	<5
Increase EPS	2.4	3.0	68	2.5	3.0	35	3.8	4.0	5	na	na	<5	2.0	2.0	26	2.5	3.0	63	na	na	<5	na	na	<5
Manage EPS volatility	1.2	1.0	67	1.1	1.0	34	1.6	1.0	5	na	na	<5	1.1	1.0	26	1.2	1.0	62	na	na	<5	na	na	<5
Reduce the amount of capital	1.0	1.0	67	0.9	0.0	34	2.0	1.0	5	na	na	<5	0.9	1.0	26	1.1	1.0	62	na	na	<5	na	na	<5

Means and Medians in Percent

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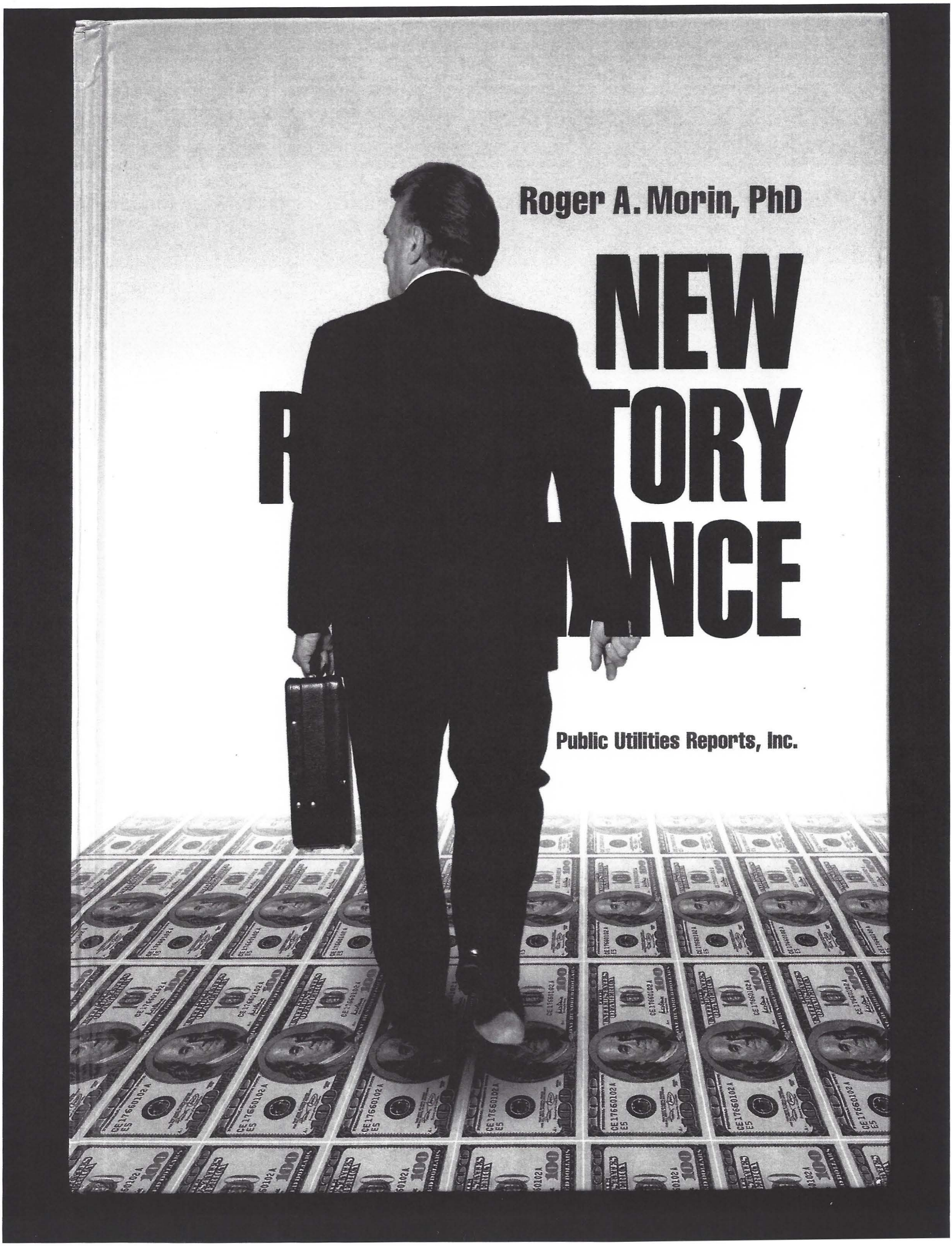
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$$K = D_1/P + g \tag{8-19}$$

is altered as follows. Since growth in book value per share results from both types of operations, now g = br + sv and not simply br, where:

s = funds raised from the sale of stock as a fraction of existing common equity
v = fraction of the funds raised from the sale of stock that accrues to shareholders at the start of the period

The only change required in the standard DCF model to recognize the expectation of continuous stock financing at the rate s is the change in the expected rate of growth from br to (br + sv). The expanded DCF model pioneered by Gordon (1974) takes the form:[4]

$$K = {}^{D_1}\!/_{P} + br + sv \tag{8-20}$$

In this expanded DCF model, v is the fraction of earnings and dividends generated by the new funds accruing to existing shareholders. To understand the meaning of v, consider a new stock issue sold at a price equal to book value, P = B. The equity of the new shareholders is equal to the funds they invest, and the existing shareholders' equity is not changed. But if the stock is sold at a price greater than book value, P > B, a portion of the funds accrues to the existing shareholders. And if the stock is sold at a price less than book value, P < B, existing shareholders experience a dilution of their equity position. Specifically, Gordon has shown that

$$v = 1 - B/P \tag{8-21}$$

where 'v' is the portion of the new funds raised that increases/decreases the book value of the existing shareholders' equity, depending on whether P > B or P < B.

The expanded DCF model in Equation 8-20 reduces to the standard DCF version if either the company does not regularly sell new stock, s = 0, or if new stock is sold at a price equal to book value, v = 0. In the latter case, new stock financing has no impact on stock price. B/P = 1 in Equation 8-21, and v is thus 0.

[4] An analogous extended DCF model was derived by Miller and Modigliani (1958, 1963), who used a slightly different valuation approach to arrive at an expression which is equivalent to Gordon's model in Equation 8-20. Using the appropriate notational translations, several authors, including Davis and Sparrow (1972) and Arzac and Marcus (1981), have shown the equivalence of the Gordon and the Miller and Modigliani versions.

Fundamentals of Corporate Finance

Fourth Edition

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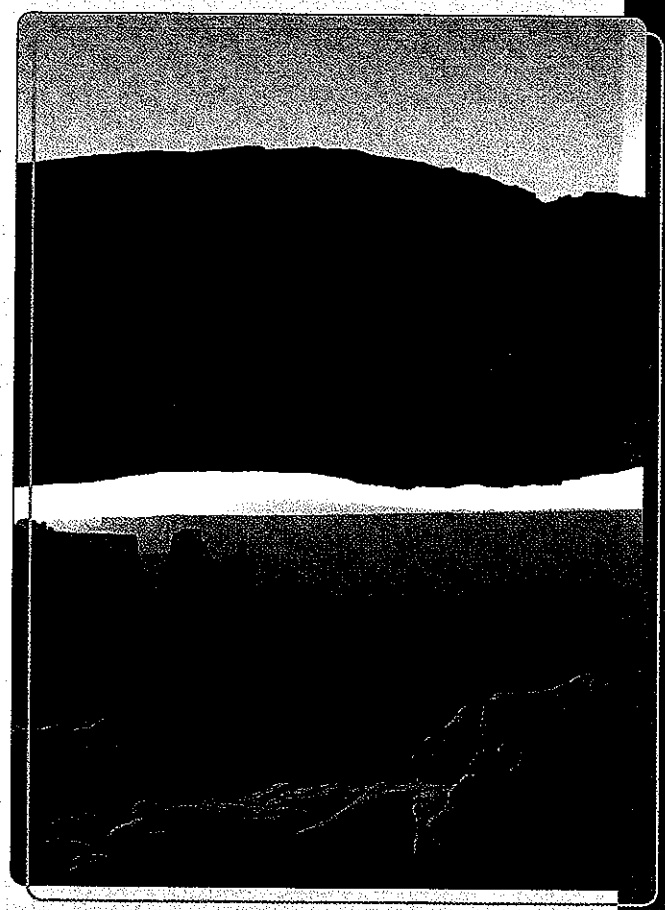

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When earnings fall unexpectedly, the payout ratio is likely to rise temporarily. Likewise, if earnings are expected to rise next year, management may feel that it can pay somewhat more generous dividends than it would otherwise have done.

Earnings not paid out as dividends are retained, or plowed back into the business. The proportion of earnings reinvested in the firm is called the *plowback ratio:*

$$\text{Plowback ratio} = 1 - \text{payout ratio} = \frac{\text{earnings} - \text{dividends}}{\text{earnings}}$$

If you multiply this figure by the return on equity, you can see how rapidly shareholders' equity is growing as a result of plowing back part of its earnings each year. Thus for Pepsi, earnings plowed back into the firm increased the book value of equity by 20.6 percent:

$$\begin{aligned}\text{Growth in equity from plowback} &= \frac{\text{earnings} - \text{dividends}}{\text{equity}} \\ &= \frac{\text{earnings} - \text{dividends}}{\text{earnings}} \times \frac{\text{earnings}}{\text{equity}} \\ &= \text{plowback ratio} \times \text{ROE} \\ &= .627 \times .328 = .206, \text{ or } 20.6\%\end{aligned}$$

If Pepsi can continue to earn 32.8 percent on its book equity and plow back 62.7 percent of earnings, both earnings and equity will grow at 20.6 percent a year.[7]

Is this a reasonable prospect? We saw in Chapter 6 that such high growth rates are unlikely to persist. While Pepsi may continue to grow rapidly for some years to come, such rapid growth will inevitably slow.

17.2 The Du Pont System

Du Pont system A breakdown of ROE and ROA into component ratios.

Some profitability or efficiency measures can be linked in useful ways. These relationships are often referred to as the **Du Pont system,** in recognition of the chemical company that popularized them.

The first relationship links the return on assets (ROA) with the firm's asset turnover ratio and its operating profit margin:

$$\textbf{ROA} = \frac{\textbf{net income + interest}}{\textbf{assets}} = \underset{\substack{\uparrow \\ \textbf{asset turnover}}}{\frac{\textbf{sales}}{\textbf{assets}}} \times \underset{\substack{\uparrow \\ \textbf{operating profit margin}}}{\frac{\textbf{net income + interest}}{\textbf{sales}}}$$

All firms would like to earn a higher return on their assets, but their ability to do so is limited by competition. If the expected return on assets is fixed by competition, firms face a trade-off between the turnover ratio and the profit margin. Thus we find that fast-food chains, which have high turnover, also tend to operate on low profit margins. Hotels have relatively low turnover ratios but tend to compensate for this with higher margins. Table 17–5 illustrates the trade-off. Both the fast-food chain and the hotel have the same return on assets. However, their profit margins and turnover ratios are entirely different.

[7] Analysts sometimes refer to this figure as the *sustainable rate of growth.* Notice that, when calculating the sustainable rate of growth, ROE would be better measured by earnings (in Pepsi's case, $2,662 million) as a proportion of equity at the *start* of the year (in Pepsi's case, $7,604 million), rather than the average of the equity at the start and end of the year. We discussed the sustainable rate of growth in Chapter 6 and we will return to it again in Chapter 18.

Investor growth expectations: Analysts vs. history

Analysts' growth forecasts dominate past trends in predicting stock prices.

James H. Vander Weide and Willard T. Carleton

For the purposes of implementing the Discounted Cash Flow (DCF) cost of equity model, the analyst must know which growth estimate is embodied in the firm's stock price. A study by Cragg and Malkiel (1982) suggests that the stock valuation process embodies analysts' forecasts rather than historically based growth figures such as the ten-year historical growth in dividends per share or the five-year growth in book value per share. The Cragg and Malkiel study is based on data for the 1960s, however, a decade that was considerably more stable than the recent past.

As the issue of which growth rate to use in implementing the DCF model is so important to applications of the model, we decided to investigate whether the Cragg and Malkiel conclusions continue to hold in more recent periods. This paper describes the results of our study.

STATISTICAL MODEL

The DCF model suggests that the firm's stock price is equal to the present value of the stream of dividends that investors expect to receive from owning the firm's shares. Under the assumption that investors expect dividends to grow at a constant rate, g, in perpetuity, the stock price is given by the following simple expression:

$$P_s = \frac{D(1+g)}{k-g} \quad (1)$$

where:

P_s = current price per share of the firm's stock;

D = current annual dividend per share;

g = expected constant dividend growth rate; and

k = required return on the firm's stock.

Dividing both sides of Equation (1) by the firm's current earnings, E, we obtain:

$$\frac{P_s}{E} = \frac{D}{E} \cdot \frac{(1+g)}{k-g} \quad (2)$$

Thus, the firm's price/earnings (P/E) ratio is a nonlinear function of the firm's dividend payout ratio (D/E), the expected growth in dividends (g), and the required rate of return.

To investigate what growth expectation is embodied in the firm's current stock price, it is more convenient to work with a linear approximation to Equation (2). Thus, we will assume that:

$$P/E = a_0(D/E) + a_1 g + a_2 k. \quad (3)$$

(Cragg and Malkiel found this assumption to be reasonable throughout their investigation.)

Furthermore, we will assume that the required

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rate of return, k, in Equation (3) depends on the values of the risk variables B, Cov, Rsq, and Sa, where B is the firm's Value Line beta; Cov is the firm's pretax interest coverage ratio; Rsq is a measure of the stability of the firm's five-year historical EPS; and Sa is the standard deviation of the consensus analysts' five-year EPS growth forecast for the firm. Finally, as the linear form of the P/E equation is only an approximation to the true P/E equation, and B, Cov, Rsq, and Sa are only proxies for k, we will add an error term, e, that represents the degree of approximation to the true relationship.

With these assumptions, the final form of our P/E equation is as follows:

$$P/E = a_0(D/E) + a_1 g + a_2 B + a_3 Cov + a_4 Rsq + a_5 Sa + e. \quad (4)$$

The purpose of our study is to use more recent data to determine which of the popular approaches for estimating future growth in the Discounted Cash Flow model is embodied in the market price of the firm's shares.

We estimated Equation (4) to determine which estimate of future growth, g, when combined with the payout ratio, D/E, and risk variables B, Cov, Rsq, and Sa, provides the best predictor of the firm's P/E ratio. To paraphrase Cragg and Malkiel, we would expect that growth estimates found in the best-fitting equation more closely approximate the expectation used by investors than those found in poorer-fitting equations.

DESCRIPTION OF DATA

Our data sets include both historically based measures of future growth and the consensus analysts' forecasts of five-year earnings growth supplied by the Institutional Brokers Estimate System of Lynch, Jones & Ryan (IBES). The data also include the firm's dividend payout ratio and various measures of the firm's risk. We include the latter items in the regression, along with earnings growth, to account for other variables that may affect the firm's stock price.

The data include:

Earnings Per Share. Because our goal is to determine which earnings variable is embodied in the firm's market price, we need to define this variable with care. Financial analysts who study a firm's financial results in detail generally prefer to "normalize" the firm's reported earnings for the effect of extraordinary items, such as write-offs of discontinued operations, or mergers and acquisitions. They also attempt, to the extent possible, to state earnings for different firms using a common set of accounting conventions.

We have defined "earnings" as the consensus analyst estimate (as reported by IBES) of the firm's earnings for the forthcoming year.[1] This definition approximates the normalized earnings that investors most likely have in mind when they make stock purchase and sell decisions. It implicitly incorporates the analysts' adjustments for differences in accounting treatment among firms and the effects of the business cycle on each firm's results of operations. Although we thought at first that this earnings estimate might be highly correlated with the analysts' five-year earnings growth forecasts, that was not the case. Thus, we avoided a potential spurious correlation problem.

Price/Earnings Ratio. Corresponding to our definition of "earnings," the price/earnings ratio (P/E) is calculated as the closing stock price for the year divided by the consensus analyst earnings forecast for the forthcoming fiscal year.

Dividends. Dividends per share represent the common dividends declared per share during the calendar year, after adjustment for all stock splits and stock dividends). The firm's dividend payout ratio is then defined as common dividends per share divided by the consensus analyst estimate of the earnings per share for the forthcoming calendar year (D/E). Although this definition has the deficiency that it is obviously biased downward — it divides this year's dividend by next year's earnings — it has the advantage that it implicitly uses a "normalized" figure for earnings. We believe that this advantage outweighs the deficiency, especially when one considers the flaws of the apparent alternatives. Furthermore, we have verified that the results are insensitive to reasonable alternative definitions (see footnote 1).

Growth. In comparing historically based and consensus analysts' forecasts, we calculated forty-one different historical growth measures. These included the following: 1) the past growth rate in EPS as determined by a log-linear least squares regression for the latest year,[2] two years, three years, . . ., and ten years; 2) the past growth rate in DPS for the latest year, two years, three years, . . ., and ten years; 3) the past growth rate in book value per share (computed as the ratio of common equity to the outstanding common equity shares) for the latest year, two years, three years, . . ., and ten years; 4) the past growth rate in cash flow per share (computed as the ratio of pretax income, depreciation, and deferred taxes to the outstanding common equity shares) for the latest year, two years, three years, . . ., and ten years; and 5) plowback growth (computed as the firm's retention ratio for the current year times the firm's latest annual return on common equity).

We also used the five-year forecast of earnings

per share growth compiled by IBES and reported in mid-January of each year. This number represents the consensus (i.e., mean) forecast produced by analysts from the research departments of leading Wall Street and regional brokerage firms over the preceding three months. IBES selects the contributing brokers "because of the superior quality of their research, professional reputation, and client demand" (IBES *Monthly Summary Book*).

Risk Variables. Although many risk factors could potentially affect the firm's stock price, most of these factors are highly correlated with one another. As shown above in Equation (4), we decided to restrict our attention to four risk measures that have intuitive appeal and are followed by many financial analysts: 1) B, the firm's beta as published by Value Line; 2) Cov, the firm's pretax interest coverage ratio (obtained from Standard & Poor's Compustat); 3) Rsq, the stability of the firm's five-year historical EPS (measured by the R^2 from a log-linear least squares regression); and 4) Sa, the standard deviation of the consensus analysts' five-year EPS growth forecast (mean forecast) as computed by IBES.

After careful analysis of the data used in our study, we felt that we could obtain more meaningful results by imposing six restrictions on the companies included in our study:

1. Because of the need to calculate ten-year historical growth rates, and because we studied three different time periods, 1981, 1982, and 1983, our study requires data for the thirteen-year period 1971-1983. We included only companies with at least a thirteen-year operating history in our study.
2. As our historical growth rate calculations were based on log-linear regressions, and the logarithm of a negative number is not defined, we excluded all companies that experienced negative EPS during any of the years 1971-1983.
3. For similar reasons, we also eliminated companies that did not pay a dividend during any one of the years 1971-1983.
4. To insure comparability of time periods covered by each consensus earnings figure in the P/E ratios, we eliminated all companies that did not have a December 31 fiscal year-end.
5. To eliminate distortions caused by highly unusual events that distort current earnings but not expected future earnings, and thus the firm's price/earnings ratio, we eliminated any firm with a price/earnings ratio greater than 50.
6. As the evaluation of analysts' forecasts is a major part of this study, we eliminated all firms that IBES did not follow.

Our final sample consisted of approximately sixty-five utility firms.[3]

RESULTS

To keep the number of calculations in our study to a reasonable level, we performed the study in two stages. In Stage 1, all forty-one historically oriented approaches for estimating future growth were correlated with each firm's P/E ratio. In Stage 2, the historical growth rate with the highest correlation to the P/E ratio was compared to the consensus analyst growth rate in the multiple regression model described by Equation (4) above. We performed our regressions for each of three recent time periods, because we felt the results of our study might vary over time.

First-Stage Correlation Study

Table 1 gives the results of our first-stage correlation study for each group of companies in each of the years 1981, 1982, and 1983. The values in this table measure the correlation between the historically oriented growth rates for the various time periods and the firm's end-of-year P/E ratio.

The four variables for which historical growth rates were calculated are shown in the left-hand column: EPS indicates historical earnings per share growth, DPS indicates historical dividend per share growth, BVPS indicates historical book value per share growth, and CFPS indicates historical cash flow per share growth. The term "plowback" refers to the product of the firm's retention ratio in the currennt year and its return on book equity for that year. In all, we calculated forty-one historically oriented growth rates for each group of firms in each study period.

The goal of the first-stage correlation analysis was to determine which historically oriented growth rate is most highly correlated with each group's year-end P/E ratio. Eight-year growth in CFPS has the highest correlation with P/E in 1981 and 1982, and ten-year growth in CFPS has the highest correlation with year-end P/E in 1983. In all cases, the plowback estimate of future growth performed poorly, indicating that — contrary to generally held views — plowback is not a factor in investor expectations of future growth.

Second-Stage Regression Study

In the second stage of our regression study, we ran the regression in Equation (4) using two different measures of future growth, g: 1) the best historically oriented growth rate (g_h) from the first-stage correlation study, and 2) the consensus analysts' forecast (g_a) of five-year EPS growth. The regression results, which are shown in Table 2, support at least

TABLE 1

Correlation Coefficients of All Historically Based Growth Estimates by Group and by Year with P/E

Historical Growth Rate Period in Years

Current Year	1	2	3	4	5	6	7	8	9	10
1981										
EPS	−0.02	0.07	0.03	0.01	0.03	0.12	0.08	0.09	0.09	0.09
DPS	0.05	0.18	0.14	0.15	0.14	0.15	0.19	0.23	0.23	0.23
BVPS	0.01	0.11	0.13	0.13	0.16	0.18	0.15	0.15	0.15	0.15
CFPS	−0.05	0.04	0.13	0.22	0.28	0.31	0.30	0.31	−0.57	−0.54
Plowback	0.19									
1982										
EPS	−0.10	−0.13	−0.06	−0.02	−0.02	−0.01	−0.03	−0.03	0.00	0.00
DPS	−0.19	−0.10	0.03	0.05	0.07	0.08	0.09	0.11	0.13	0.13
BVPS	0.07	0.08	0.11	0.11	0.09	0.10	0.11	0.11	0.09	0.09
CFPS	−0.02	−0.08	0.00	0.10	0.16	0.19	0.23	0.25	0.24	0.07
Plowback	0.04									
1983										
EPS	−0.06	−0.25	−0.25	−0.24	−0.16	−0.11	−0.05	0.00	0.02	0.02
DPS	0.03	−0.10	−0.03	0.08	0.15	0.21	0.21	0.21	0.22	0.24
BVPS	0.03	0.10	0.04	0.09	0.15	0.16	0.19	0.21	0.22	0.21
CFPS	−0.08	0.01	0.02	0.08	0.20	0.29	0.35	0.38	0.40	0.42
Plowback	−0.08									

two general conclusions regarding the pricing of equity securities.

First, we found overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically oriented growth measures in predicting the firm's stock price. In every case, the R^2 in the regression containing the consensus analysts' forecast is higher than the R^2 in the regression containing the historical growth measure. The regression coefficients in the equation containing the consensus analysts' forecast also are considerably more significant than they are in the alternative regression. These results are consistent with those found by Cragg and Malkiel for data covering the period 1961-1968. Our results also are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy–and–sell decisions.

TABLE 2

Regression Results
Model I

Part A: *Historical*

$P/E = a_0 + a_1 D/E + a_2 g_h + a_3 B + a_4 Cov + a_5 Rsq + a_6 Sa$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	$\hat{a}_3$	$\hat{a}_4$	$\hat{a}_5$	$\hat{a}_6$	R^2	F Ratio
1981	−6.42*	10.31*	7.67*	3.24	0.54*	1.42*	57.43	0.83	46.49
	(5.50)	(14.79)	(2.20)	(2.86)	(2.50)	(2.85)	(4.07)		
1982	−2.90*	9.32*	8.49*	2.85	0.45*	−0.42	3.63	0.86	65.53
	(2.75)	(18.52)	(4.18)	(2.83)	(2.60)	(0.05)	(0.26)		
1983	−5.96*	10.20*	19.78*	4.85	0.44*	0.33	32.49	0.82	45.26
	(3.70)	(12.20)	(4.83)	(2.95)	(1.89)	(0.50)	(1.29)		

Part B: *Analysis*

$P/E = a_0 + a_1 D/E + a_2 g_a + a_3 B + a_4 Cov + a_5 Rsq + a_6 Sa$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	$\hat{a}_3$	$\hat{a}_4$	$\hat{a}_5$	$\hat{a}_6$	R^2	F Ratio
1981	−4.97*	10.62*	54.85*	−0.61	0.33*	0.63*	4.34	0.91	103.10
	(6.23)	(21.57)	(8.56)	(0.68)	(2.28)	(1.74)	(0.37)		
1982	−2.16*	9.47*	50.71*	−1.07	0.36*	−0.31	119.05*	0.90	97.62
	(2.59)	(22.46)	(9.31)	(1.14)	(2.53)	(1.09)	(1.60)		
1983	−8.47*	11.96*	79.05*	2.16	0.56*	0.20	−34.43	0.87	69.81
	(7.07)	(16.48)	(7.84)	(1.55)	(3.08)	(0.38)	(1.44)		

Notes:

* Coefficient is significant at the 5% level (using a one-tailed test) and has the correct sign. T-statistic in parentheses.

Second, there is some evidence that investors tend to view risk in traditional terms. The interest coverage variable is statistically significant in all but one of our samples, and the stability of the operating income variable is statistically significant in six of the twelve samples we studied. On the other hand, the beta is never statistically significant, and the standard deviation of the analysts' five-year growth forecasts is statistically significant in only two of our twelve samples. This evidence is far from conclusive, however, because, as we demonstrate later, a significant degree of cross-correlation among our four risk variables makes any general inference about risk extremely hazardous.

Possible Misspecification of Risk

The stock valuation theory says nothing about which risk variables are most important to investors. Therefore, we need to consider the possibility that the risk variables of our study are only proxies for the "true" risk variables used by investors. The inclusion of proxy variables may increase the variance of the parameters of most concern, which in this case are the coefficients of the growth variables.[4]

To allow for the possibility that the use of risk proxies has caused us to draw incorrect conclusions concerning the relative importance of analysts' growth forecasts and historical growth extrapolations, we have also estimated Equation (4) with the risk variables excluded. The results of these regressions are shown in Table 3.

Again, there is overwhelming evidence that the consensus analysts' growth forecast is superior to the historically oriented growth measures in predicting the firm's stock price. The R^2 and t-statistics are higher in every case.

CONCLUSION

The relationship between growth expectations and share prices is important in several major areas of finance. The data base of analysts' growth forecasts collected by Lynch, Jones & Ryan provides a unique opportunity to test the hypothesis that investors rely more heavily on analysts' growth forecasts than on historical growth extrapolations in making security buy–and–sell decisions. With the help of this data base, our studies affirm the superiority of analysts' forecasts over simple historical growth extrapolations in the stock price formation process. Indirectly, this finding lends support to the use of valuation models whose input includes expected growth rates.

TABLE 3

Regression Results
Model II

Part A: *Historical*

$P/E = a_0 + a_1 D/E + a_2 g_h$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	R^2	F Ratio
1981	−1.05	9.59	21.20	0.73	82.95
	(1.61)	(12.13)	(7.05)		
1982	0.54	8.92	12.18	0.83	167.97
	(1.38)	(17.73)	(6.95)		
1983	−0.75	8.92	12.18	0.77	107.82
	(1.13)	(12.38)	(7.94)		

Part B: *Analysis*

$P/E + a_0 + a_1 D/E + a_2 g_a$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	R^2	F Ratio
1981	3.96	10.07	60.53	0.90	274.16
	(8.31)	(8.31)	(20.91)	(15.79)	
1982	−1.75	9.19	44.92	0.88	246.36
	(4.00)	(4.00)	(21.35)	(11.06)	
1983	−4.97	10.95	82.02	0.83	168.28
	(6.93)	(6.93)	(15.93)	(11.02)	

Notes:
* Coefficient is significant at the 5% level (using a one-tailed test) and has the correct sign. T-statistic in parentheses.

[1] We also tried several other definitions of "earnings," including the firm's most recent primary earnings per share prior to any extraordinary items or discontinued operations. As our results were insensitive to reasonable alternative definitions of "earnings" we report only the results for the IBES consensus.

[2] For the latest year, we actually employed a point-to-point growth calculation because there were only two available observations.

[3] We use the word "approximately," because the set of available firms varied each year. In any case, the number varied only from zero to three firms on either side of the figures cited here.

[4] See Maddala (1977).

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U.S. Securities and Exchange Commission

Securities and Exchange Commission

17 CFR PART 242

[Release Nos. 33-8193; 34-47384; File No. S7-30-02]

RIN 3235-AI60

Regulation Analyst Certification

Agency: Securities and Exchange Commission.

Action: Final rule.

Summary: The Securities and Exchange Commission ("Commission" "SEC" or "we") is adopting new Regulation Analyst Certification ("Regulation AC"). Regulation AC requires that brokers, dealers, and certain persons associated with a broker or dealer include in research reports certifications by the research analyst that the views expressed in the report accurately reflect his or her personal views, and disclose whether or not the analyst received compensation or other payments in connection with his or her specific recommendations or views. Broker-dealers would also be required to obtain periodic certifications by research analysts in connection with the analyst's public appearances. By requiring these certifications and disclosures, Regulation AC should promote the integrity of research reports and investor confidence in those reports.

Effective Date: April 14, 2003.

For Further Information Contact: James Brigagliano, Thomas Eidt, or Racquel Russell in the Office of Risk Management and Control, Division of Market Regulation, at (202) 942-0772.

Supplementary Information: We are adopting new Regulation Analyst Certification[1] under the Securities Act of 1933 ("Securities Act") and the Securities Exchange Act of 1934 ("Exchange Act").

I. Introduction and Summary of Regulation Analyst Certification

During 1999, the Commission and Congress began to closely examine research analysts' conflicts of interest. We were particularly concerned that many investors who rely on analysts' recommendations may not know, among other things, that favorable research coverage could be used to market the investment banking services provided by an analyst's firm, and that an analyst's compensation may be based significantly on generating investment banking business. Moreover, news reports stated that some analysts had issued reports that did not reflect their true beliefs and communicated to institutional investors views that differed materially from those expressed in their research reports.[2] Regulation AC, together with other efforts, is intended to address these issues. [3]

On May 10, 2002, we approved rule changes filed by the NYSE and NASD

governing analyst conflicts of interest.[4] On December 31, 2002, we noticed for comment a second set of proposed rules filed by the NYSE and NASD to further address research analyst conflicts of interest.[5] These self-regulatory organization rules are part of an ongoing process on our part and that of the NYSE and NASD to address conflicts of interest affecting the integrity and objectivity of research by securities firms. Regulation AC is intended to complement other rules governing conflicts of interest disclosure by research analysts, including NYSE Rule 472, NASD Rule 2711, and the anti-fraud provisions of the federal securities law.

On July 30, 2002, President Bush signed into law the Sarbanes-Oxley Act of 2002 ("SOA").[6] Section 501 of the SOA requires that rules governing analyst conflicts be adopted within a year of enactment, including rules: limiting the supervision and compensatory evaluation of securities analysts; defining periods in which brokers or dealers engaged in a public offering of a security as underwriter or dealer may not publish research on such security; and requiring securities analysts and brokers or dealers to disclose specified conflicts of interest. The Commission voted to propose Regulation AC on July 24, 2002, before the passage of the SOA. [7] In the Proposing Release, the Commission noted that it would abide by the directives of the SOA as it continues to address analyst conflicts of interest issues, including with respect to the possible adoption of Regulation AC.

The Commission received twenty-one comment letters in response to the Proposing Release,[8] which generally supported the proposed regulation. After considering the comments, we are adopting Regulation AC with modifications to the rule to reflect commenters' concerns and to clarify and limit certain provisions. We are also providing interpretive guidance requested by commenters.

A. Certifications in Connection with Research Reports

As adopted, Regulation Analyst Certification requires that brokers, dealers, and their associated persons that are "covered persons"[9] that publish,[10] circulate, or provide research reports include in those research reports:

> (A) a statement by the research analyst (or analysts) certifying that the views expressed in the research report accurately reflect such research analyst's personal views about the subject securities and issuers; and
>
> (B) a statement by the research analyst (or analysts) certifying either:
>
> > (1) that no part of his or her compensation was, is, or will be directly or indirectly related to the specific recommendations or views contained in the research report; or
> >
> > (2) that part or all of his or her compensation was, is, or will be directly or indirectly related to the specific recommendations or views contained in the research report. If the analyst's compensation was, is, or will be directly or indirectly related to the specific recommendations or views contained in the research report, the statement must include the source, amount, and purpose of such compensation, and further disclose that it may influence the recommendation in the research report.

All certifications must be clear and prominent.[11] If the analyst is unable to

certify that the report accurately reflects his or her personal views, distribution of the report by the broker-dealer or covered person would be in violation of Regulation AC. Similarly, if the report does not contain one of the two alternative compensation certifications, distribution of the report by the broker-dealer or covered person would be in violation of Regulation AC.[12]

Research reports generally contain an analyst's summary rating of the security based on his or her particular firm's rating system, as well as an analysis. The summary rating or recommendation is often one word (e.g., buy, sell, overweight), while the analysis may be very detailed and lengthy. Generally, the analysis explains the basis for the rating and provides extensive supplementary information, which, in some instances, significantly qualifies or conditions the stated rating. The Regulation AC certification that the views in the report accurately reflect the analyst's personal views applies to the analysis as reflected in the rating as well as the substance of a research report.

A rating is designed to be a severable summary statement of the analysis in the report. In situations where the analysis significantly qualifies or conditions the stated rating, a communication by the firm or the analyst of only the rating to an investor as representing the analyst's views about the security could be misleading.[13] Further, where the analysis contradicts the stated rating, an analyst and the firm could be in violation of the anti-fraud provisions of the federal securities laws. A rating that contradicts the analysis could also render false the analyst's certification, because the analyst's certification reflects both the analysis as well as the rating.

B. Certifications in Connection with Public Appearances

Under Regulation AC, broker-dealers must make and keep records related to public appearances by research analysts. Specifically, if a broker-dealer publishes, circulates, or provides a research report prepared by a research analyst employed by the broker-dealer or a covered person, the broker-dealer is required to make a record within thirty days after each calendar quarter in which the research analyst made any public appearance, that includes:

- A statement by the research analyst attesting that the views expressed by the research analyst in all public appearances during the calendar quarter accurately reflected the research analyst's personal views at that time about any and all of the subject securities or issuers; and

- A written statement by the research analyst certifying that no part of such research analyst's compensation was, is, or will be directly or indirectly related to any specific recommendations or views expressed in any such public appearance.

In cases where the broker-dealer does not obtain a statement by the research analyst in connection with public appearances as described above, the broker-dealer must promptly notify its examining authority, designated pursuant to Section 17(d) of the Exchange Act and Rule 17d-2 thereunder, that the analyst did not provide certification in connection with public appearances. In addition, for 120 days following such notification, the broker-dealer must disclose in any research report it distributes authored by that analyst that the analyst did not provide certification specified in Rule 502 (a) of Regulation AC. Further, broker-dealers must keep and maintain

these records pursuant to Rule 17a-4.

II. Response to Comments on Regulation Analyst Certification

In the Proposing Release, the Commission sought comment on specific aspects of the proposed regulation, as well as general comments. We received twenty-one comment letters in response to the release. Many commenters expressed support for Regulation AC, although a number also expressed concerns regarding one or more aspects of the proposal, and some suggested alternatives for addressing particular issues. We are adopting Regulation AC with modifications from the proposal that clarify or limit provisions or reflect commenters' views.

A. Defined Terms

We requested comment on whether the proposed definitions of "research report," "research analyst," or "public appearance" should be broader or narrower than proposed. Eleven commenters discussed the scope of the definitions proposed in Regulation AC and noted differences in certain respects compared to definitions contained in the self-regulatory organization ("SRO") rules and the SOA.[14] Generally, commenters believed that compliance efforts would be significantly enhanced by the use of consistent terminology throughout the rules wherever possible.[15] The Commission has conformed the terminology and definitions of Regulation AC to the SRO rules and the SOA wherever appropriate.

1. Definition of "Research Analyst"

Commenters noted that Regulation AC defines "research analyst" more broadly than do the current SRO analyst rules and the SOA. Specifically, the Regulation AC definition as proposed covers "any natural person," rather than only "associated persons of a member" (in the case of the SRO rules) or "associated persons of a registered broker or dealer" (in the case of the SOA). Commenters argued that Regulation AC applies to any person, including employees of investment advisers, foreign entities, or any other third party that prepares a research report that is circulated by a broker-dealer or associated persons.[16]

In this regard, Regulation AC is designed to be broader than the SRO rules and the SOA in that it applies to brokers, dealers, and certain associated persons[17], which may also include investment advisers and others that prepare research reports. We believe that the broad scope of Regulation AC is warranted because Regulation AC imposes core standards of integrity that should pertain to all research distributed by broker-dealers and covered persons. On the other hand, we note that Regulation AC is narrower than the SRO rules and the SOA in that its certification requirements apply only to the research analyst or analysts primarily responsible for the content of a research report; junior analysts are not required to certify.[18] This distinction is reasonable because the core integrity standards promoted by Regulation AC are achieved where the analysts primarily responsible for the views expressed in the research report are required to certify. In comparison, the coverage of junior analysts by the SRO rules is appropriate because the concerns those provisions seek to address (for example, trading ahead of research reports) exist with respect to all analysts associated with a member firm and those persons who report to analysts.

2. Definition of "Covered Person"

In response to comments, we have added the definition of "covered person" to narrow the scope of persons to which Regulation AC applies. Covered person means persons associated with a broker or dealer,[19] but not including an associated person that has no officers or employees in common with the broker or dealer and where the broker or dealer maintains and enforces written policies and procedures reasonably designed to prevent the broker or dealer or any of its controlling persons, officers, or employees from influencing the activities of research analysts and the content of research reports prepared by the associated person. In adopting Regulation AC, we have sought to focus the rule on research that appears to be most susceptible to pressures that might compromise its integrity, for example pressures to generate investment banking business.

We believe that it is unnecessary to apply Regulation AC to research published, circulated, or provided by associated persons who have a sufficient level of independence from the broker or dealer with which they are associated. Associated persons who meet the independence criteria in this definition should have a sufficient level of independence so that pressures from the broker-dealer with which they are associated should not compromise their research. In order to avoid the possibility that an associated person might incorrectly believe that the broker-dealer had policies and procedures to prevent influencing the research of the associated person and, therefore, fail to certify when certification was required, we have added a provision to Regulation AC (Rule 504) that requires a broker or dealer to notify its associated persons that issue research reports as to whether the broker or dealer maintains and enforces such written policies and procedures and whether the associated person has any officers (or persons performing similar functions) or employees in common with the broker or dealer who can influence the activities of research analysts or the content of research reports and, if so, the identity of those persons.[20] We also would not expect that such policies and procedures would interfere with other communications between the associated person and the broker-dealer made in the ordinary course of business and not in violation of any other provision of the securities laws.

We have also excluded from the rule investment advisers that are prohibited under Section 203A of the Investment Advisers Act of 1940[21] ("Advisers Act") from registering with the Commission as investment advisers and not otherwise registered or required to be registered as a broker-dealer. Section 203A was added to the Advisers Act by the National Securities Markets Improvement Act of 1996 ("NSMIA"), which amended the Advisers Act to divide responsibility for regulating investment advisers between the Commission and state securities authorities.[22] Section 203A of the Advisers Act effects this division by generally prohibiting investment advisers from registering with us unless they have at least $25 million of assets under management or advise a registered investment company.[23] Advisers prohibited from registering with us are subject to the regulation of state securities authorities, but also continue to be subject to the federal securities laws, including the anti-fraud provisions of the federal securities laws.

We also make clear that no provision of the regulation shall apply to the publisher of any newspaper, news magazine, or business or financial publication of general and regular circulation that is not registered or

required to be registered with the Commission as a broker or dealer or investment adviser. Regulation AC was never intended to govern media coverage of issuers.[24]

3. Definition of "Research Report"

The Commission requested comment on whether the definition of "research report" should be broader or narrower than proposed. Commenters discussed several aspects of the proposed definition, including whether it should cover debt securities, whether it should include electronic communications, and guidance concerning what will and will not be considered a research report.

a. Application to Debt Securities

We specifically requested comment on whether the proposed definition of "research report" should be limited to cover only equity securities. Five commenters discussed the application of Regulation AC to fixed income and all supported the application to debt to some extent.[25]

The Commission has determined that applying the requirements of Regulation AC to debt securities as well as equity securities would benefit investors because it would provide to debt investors the same benefits as equity investors by promoting the integrity of research reports and confidence in research analyst recommendations.

b. Electronic Communications

Commenters noted that, unlike the SRO rules, the proposed definition of "research report" in Regulation AC did not explicitly include "electronic communications," and requested that the Commission clarify that the regulation would apply to research reports transmitted electronically.

The Commission believes that electronic communications were included under proposed Regulation AC's definition of "research report." However, in response to commenters' concerns, the Commission has modified the proposed definition of "research report" to explicitly include written communications in electronic form.

c. What Constitutes a Research Report?

The Commission has deleted the "recommendation" element from Regulation AC's proposed definition of "research report" to conform to the definition in the SOA. Therefore, "research report" is defined as "a written communication (including an electronic communication) that includes an analysis of a security or an issuer and provides information reasonably sufficient upon which to base an investment decision."

Commenters requested that the Commission provide guidance concerning what types of communications the rule is not intended to cover.[26] Commenters also requested clarification that Regulation AC would not apply to internal communications.

It is not possible to provide a complete list of all types of communications that would or would not fall within the definition of "research report."

Whether a particular communication constitutes a research report for the purposes of Regulation AC will turn on the individual facts and circumstances surrounding that communication. In general, however, the following communications would not be research reports if they do not include an analysis of, or recommend or rate, individual securities or companies:

- Reports discussing broad-based indices, such as the Russell 2000 or S&P 500 index.
- Reports commenting on economic, political, or market conditions.
- Reports commenting on or analyzing particular types of debt securities or characteristics of debt securities.
- Technical analysis concerning the demand and supply for a sector, index, or industry based on trading volume and price.
- Reports that recommend increasing or decreasing holdings in particular industries or sectors or types of securities.

The following communications would generally not be research reports even if they recommend or rate individual securities or companies:

- Statistical summaries of multiple companies' financial data (including listings of current ratings) that do not include any analysis of individual companies' data.
- An analysis prepared for a specific person or a limited group of fewer than fifteen persons.[27]
- Periodic reports or other communications prepared for investment company shareholders or discretionary investment account clients discussing past performance or the basis for previously made discretionary investment decisions.
- Internal communications that are not given to customers.

4. Definition of "Third party research analyst"

In response to commenters' concerns, we have added a definition of "third party research analyst" in order to refine the scope of Regulation AC. A "third party research analyst" is, with respect to a particular broker or dealer, any research analyst not employed by that broker or dealer or any associated person of that broker or dealer. With respect to a covered person, a "third party research analyst" is any research analyst not employed by that covered person, by the broker or dealer with whom that covered person is associated, or by any other associated person of the broker or dealer with whom that covered person is associated. We believe that research prepared by third party research analysts will not be susceptible to pressures from broker-dealers who distribute their research provided that the analyst's employer meets certain independence criteria.

B. Discussion of Certification Requirements

1. Certification by the Primarily Responsible Analyst

Commenters requested clarification on identifying the research analyst that

would be required to make the certifications. Commenters argued that multiple certifications would likely be confusing or have other undesirable effects.[28]

Regulation AC requires that the analyst or analysts primarily responsible for the preparation of the content of a research report comply with the certification requirements. Thus, certification by junior analysts involved in the preparation of a research report is not necessary.[29] In some cases, however, there may be more than one research analyst primarily responsible for the content of a research report. In such instances, all analysts who are primarily responsible for the views expressed in the report must provide the certifications. Removing the names of all analysts from a report would not allow the firm to avoid including the required certifications and disclosures; the analyst or analysts primarily responsible for the report must certify.

2. Quantitative and Technical Research

Commenters argued that research based on quantitative and technical models may not be attributed to a particular analyst, may not reflect an analyst's views, and therefore, requested that the Commission provide guidance that these types of research would not be covered.[30] One commenter suggested, as an alternative, that Regulation AC should require a certification by the firm that the views expressed in the report are derived from the firm's systematic quantitative research model.[31]

The Commission has determined that, in cases where there is no identified analyst because the report is based on the firm's quantitative or technical model, the firm itself may provide the certifications that the views expressed in the research report accurately reflect the firm's quantitative research model, and that no part of the firm's compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views disclosed in the research report.

However, tying an analyst's compensation to the performance of a quantitative or technical model would indicate that the report is the product of the analyst's subjective views (reflected by the design of the model employed). In that case, that analyst must certify the report containing the model's results in accordance with Rule 501 of Regulation AC.

C. Certifications or Disclosures During Public Appearances

We requested comment on what, if any, disclosures should be required during public appearances by analysts. The four commenters that addressed this issue generally were opposed to requiring certifications during analyst public appearances. [32] We have determined not to require certifications during public appearances by analysts.

The Commission believes that the proposed quarterly certification requirements in connection with analyst public appearances are sufficient. If the analyst does not provide a certification in connection with public appearances, Rule 502 of Regulation AC requires the broker-dealer to provide readers of research reports that it distributes, as well as the broker-dealer's designated examining authority, with notice that the analyst did not provide the certifications.[33] A Rule 502(b) notice in a research report must be in plain English.

D. Compendium Reports

The Commission requested comment on whether Regulation AC should make allowances for compendium research reports covering six or more securities. Commenters that discussed the treatment of certifications in compendium research reports believed that Regulation AC should permit the required disclosures to appear in a place other than the report itself. [34] Most of these commenters specifically supported treatment of compendium reports for the purpose of Regulation AC similar to the treatment allowed under SRO rules. Under SRO rules, members are not obligated to include disclosures in compendiums if the report directs readers to a toll-free number or postal address to write for required disclosures.[35] Electronic compendiums may instead include a hyperlink and paper compendiums may also include a web address where disclosures are located. Two commenters suggested the use of a combined certification that each analyst referenced in the report certifies that the analysis attributed to him or her accurately reflects his or her views.[36]

The Commission has determined not to permit treatment of compendium research reports in a manner similar to that permitted by the SROs because, unlike the SRO rules, the certifications required by Regulation AC are very concise. Nonetheless, when a research report covers more than one company and each research analyst required to certify with respect to the views expressed in a portion of the report is able to certify that: (a) the views expressed in the research report accurately reflect such research analyst's personal views about the subject securities and companies; and (b) that no part of his or her compensation was, is, or will be directly or indirectly related to the specific recommendation or views contained in the research report, the firm may comply with Regulation AC by including one clear and prominent combined certification that, as to each company covered, the respective research analyst (or analysts) certifies as to (a) and (b) above.[37]

E. Application of Regulation AC to Investment Advisers and Banks

Regulation AC is directed at brokers, dealers, and covered persons, because we believe that these entities are subject to the greatest conflicts. Therefore, investment advisers and banks, among others, may be required to comply with the regulation if they are covered persons of a broker-dealer. The Commission noted in the Proposing Release that the term "research analyst" would not include personnel of an investment adviser, such as a mutual fund portfolio manager, who are not principally responsible for preparing research reports, even if the individuals are registered persons of a broker-dealer (similar to the guidance provided by the SROs in the joint interpretive memorandum).[38] The Commission requested comment on whether the regulation should cover banks that are not associated persons and other independent entities, and whether the rule should explicitly exclude investment advisers.

Commenters who addressed the application of Regulation AC to investment advisers generally opposed the rule's coverage of investment advisers and investment advisory personnel.[39] Some commenters called for the specific exclusion of investment advisers.[40] Commenters who addressed the application of Regulation AC to banks generally opposed the rule's coverage of banks.[41] One commenter favored the application of Regulation AC to investment advisers and banks.[42]

The Commission has determined that Regulation AC should not exclude all

investment advisers or banks that are associated with broker-dealers. However, as discussed above, the definition of "covered person" substantially narrows the scope of persons associated with a broker-dealer, such as investment advisers and banks, that are subject to Regulation AC. Where the broker-dealer has informational and structural separations from its associated person, the rule does not apply to that associated person. Where the protections are lacking, however, with respect to a person associated with a broker-dealer, that person is a covered person.[43] Accordingly, if an investment adviser or bank is a covered person and publishes, circulates, or provides research reports, the research report certification provisions of Regulation AC will apply. We believe those investment advisers and banks that do not meet the independence criteria that would exclude them from the definition of "covered person" may be subject to greater conflicts than are other investment advisers and banks. Specifically, a broker-dealer's investment banking department could pressure these investment adviser or bank affiliates to comment favorably in a research report or public appearance about a client or prospective client. Moreover, if associated persons that are covered persons were not subject to the certification requirements of Regulation AC, broker-dealers could attempt to funnel research through them to avoid complying with Regulation AC.[44]

F. Application of Regulation AC to Third Party Research

In Proposing Regulation AC, we did not propose to treat research prepared by third parties but distributed by a broker-dealer differently from research produced by the broker-dealer itself. Commenters argued that broker-dealers should not be responsible for certifying research by independent third parties. Moreover, they pointed out practical problems, including the difficulty of tracking analysts employed by third parties.[45] They also cited increased costs. They argued that firms would discontinue providing the valuable service of making third party research available to customers.[46]

We have determined not to apply Regulation AC where a broker-dealer distributes research prepared by a third party research analyst whose employer satisfies certain independence criteria. The independence criteria require that the third party research analyst's employer does not have officers or employees in common with the broker-dealer or covered person distributing its research, and that the broker-dealer has written policies and procedures designed to prevent the broker-dealer, its controlling persons, officers, and employees from influencing the activities of the third party research analyst and the content of his or her research reports. We believe that research analysts employed by these independent third parties will not be sufficiently susceptible to pressures from distributing broker-dealers to warrant certification. Where a broker-dealer distributes the research of a third party that does not meet the independence criteria, however, the broker-dealer must confirm that the research report includes the same research analyst certification as required by Regulation AC.

Commenters argued that it would be difficult to track analysts employed by third parties, some of whom are overseas, in order to monitor their public appearances and obtain written statements from them. In response to commenters' concerns, we have determined that broker-dealers who distribute third party research are not required to obtain the public appearance certifications required by Rule 502 of Regulation AC with respect to public appearances by third party research analysts.

G. Application of Regulation AC to Foreign Research

In proposing Regulation Analyst Certification, the Commission did not distinguish between research that was issued by a U.S. entity and research that was issued by a non-U.S. entity. Several commenters raised the issue of the Regulation's effect on research originating from a foreign entity. These commenters generally opposed the proposed scope of Regulation AC, which captured foreign entities (and their associated persons) that issue research reports, including those who are not required to be registered with the Commission under Section 15 of the Exchange Act.[47]

In light of these comments, we have created a narrow exception for foreign persons that are located outside of the United States and are not associated with a registered broker-dealer that prepares and provides research on foreign securities[48] to major United States institutions in the U.S. in accordance with the provisions of Rule 15a-6(a)(2). In these instances, the foreign person is excepted from the requirements of Regulation AC.

In addition, in the case of a research analyst employed outside the United States by a foreign person located outside the United States, Rule 502 of Regulation AC only applies to public appearances while the research analyst is physically present in the United States.

H. Supervision and Oversight

Commenters requested that the Commission clarify that the certification pertaining to the analyst's personal views is not intended to prevent research supervisors or review committees from seeking changes to the research product.[49] One commenter argued that Regulation AC should not impede the ability of a supervisor or a review committee to require that a report follow a written firm policy on when a research report can upgrade or downgrade a rating, or when it must withhold a rating to prevent conflicts or for other reasons.[50] Commenters argued that certification also should not preclude the ability of an analyst or a firm to modify the report to due to a change in the analyst's opinion or to remove statements that create legal or regulatory concerns.[51]

The certification required by Rule 501 of Regulation AC does not impede the oversight or review of research reports. If, at the end of the revision process, the analyst still believes that the report accurately reflects his or her personal views about the subject securities or issuers, then that analyst may certify and the firm may use the research report. If, however, after the review process the research report no longer reflects the analyst's personal views, then that analyst would be unable to certify and the firm would not be in compliance with Regulation AC if it uses the research report without a certification.

I. Regulation AC and Fraud Liability Under Federal Securities Laws

Several commenters requested that the Commission reiterate the position stated in the Proposing Release that Regulation AC does not impose new liability on analysts or their firms.[52] Regulation AC formalizes and potentially adds rigor to analysts' responsibilities to express their views truthfully and without guile.[53] Regulation AC makes explicit the representations that are already implicit when an analyst publishes his or her views — that the analysis of a security published by the analyst reflects the analyst's honestly held views.[54]

Regulation AC does not alter any other existing obligation under the federal securities laws for research analysts or broker-dealers.[55] A research report contains an inherent representation that the views expressed in the report are not knowingly false and do not omit material facts necessary in order to make statements made not misleading.[56] Thus, even without Regulation AC, analysts may be found to have violated the anti-fraud provisions of the federal securities laws if they make baseless recommendations or recommendations that they disbelieve.[57]

J. Performance-based Compensation

Commenters expressed concern that Regulation AC could be read to require disclosure of analyst compensation arrangements based on the accuracy or performance of the views expressed as to the subject company's prospects.[58] Commenters thought that the compensation disclosure provision should be clarified to only require disclosure of compensation that was intended to influence or induce the particular view expressed in the research report.[59]

In the Proposing Release, the Commission noted that Regulation AC does not preclude an analyst from providing otherwise permissible services to his or her firm's investment banking department, and it does not prohibit analysts generally from receiving compensation for covering issuers or for preparing research reports. Instead, Regulation AC focuses on disclosure where the analyst compensation that is related to the specific recommendations or views expressed by the research analyst in the research report. Regulation AC is not intended to address compensation based on the performance of the views expressed regarding the securities discussed.

III. Paperwork Reduction Act

Regulation AC contains "collection of information" requirements within the meaning of the Paperwork Reduction Act of 1995 ("PRA").[60] We have submitted the proposal to the Office of Management and Budget ("OMB") for review in accordance with the PRA.[61] An agency may not conduct or sponsor, and a person is not required to respond to, an information collection unless it displays a currently valid OMB control number.

In the Proposing Release, the Commission solicited comments on the collection of information requirements. In response to comments, the Commission has revised the estimates published in the Proposing Release regarding the collection of information burdens associated with the new rule.

A. Summary of Collection of Information

Regulation AC generally requires that research reports published, circulated, or provided by a broker or dealer or covered person contain a statement attesting that the views expressed in each research report accurately reflect the analyst's personal views and whether or not the research analyst received or will receive any compensation in connection with the views or recommendations expressed in the research report. Regulation AC also requires broker-dealers to, on a quarterly basis, make, keep, and maintain records of research analyst statements regarding whether the views expressed in public appearances accurately reflected the analyst's personal views, and whether any part of the analyst's compensation is related to the specific recommendations or views expressed in the public appearance.

B. Reporting and Cost Burden Estimates

Regulation AC provides that brokers, dealers, and covered persons must include in research reports they publish, circulate, or provide certain certifications and disclosures about the analyst's views expressed in the research reports and any relationship between the analyst's compensation and the specific recommendations or views expressed. The regulation also requires broker-dealers to periodically make, keep, and maintain records of research analyst certifications and disclosures in connection with public appearances.

The staff of the Commission believes that the average amount of time it would take to include the required certifications and disclosures in each research report is one minute per report. In the Proposing Release, the Commission staff estimated that broker-dealers publish approximately 657,000 research reports per year. One commenter provided the Commission with data in response to the Proposing Release.[62] After considering this additional information, the staff of the Commission believes that broker-dealers publish approximately 1,375,865 research reports per year.[63] Therefore, the Commission estimates that the total annual burden in hours for broker-dealers to comply with the research report certification and disclosure requirements is approximately 22,930 hours per year [(1 minute x 1,375,865 reports) / 60 minutes].

The Commission staff expects that research analysts will likely be the employees primarily charged with executing certifications and including them in research reports. According to industry sources, research analysts, on average, earn $189,250 per year, for an hourly pay rate of approximately $90. Including 35% overhead, Commission staff estimates that the hourly pay rate for a research analyst would be approximately $121.50. Therefore, the Commission estimates that the total annual burden in dollars for broker-dealers to comply with the research report certification and disclosure requirements is approximately $2,785,995.00[64] per year [22,930 hours x $121.50 per hour].

Rule 501 of Regulation AC, which applies to research reports, may also impose requirements on certain entities if they are associated with a broker-dealer and meet the definition of "covered person." However, "covered persons" are not subject to Rule 502 of Regulation AC, which addresses pubic appearances. The Commission estimates that approximately 2,650 SEC registered investment advisers are associated with a broker-dealer. We believe that not all of these entities write research reports, and that those who do write research reports write relatively few. Of those investment advisers that are associated with a broker-dealer and that write research reports, we do not believe that all of them will meet the definition of a "covered person," as defined by Regulation AC. As a conservative estimate, however, if all SEC registered investment advisers are covered persons and on average publish as many research reports per year as the average broker-dealer (250 research reports), the estimated total number of research reports published by SEC registered investment advisers who are associated with a broker-dealer would be approximately 662,500 [250 x 2,650].[65] Therefore, the Commission estimates that the total annual analyst certification burden in hours for these investment advisers would be 11,040 hours [(1 minute x 662,500 research reports) / 60 minutes]. The Commission estimates that the annual burden in dollars of complying with the research report certification and disclosure requirements for SEC registered investment advisers is approximately $1,341,360 per year[66] [11,040 x

$121.50]. Unlike Rule 501, Rule 502 of Regulation AC (public appearances) does not apply to covered persons. We note, however, that we believe that a significant number of associated persons would not be "covered person[s]," as defined in Rule 500 of Regulation AC and, as a result, the aggregate burden for persons associated with broker-dealers to comply with the research report certification and disclosure requirements will be significantly lower.

The staff of the Commission believes that the research analyst will prepare the quarterly statement required for public appearances. The staff estimates that the average amount of time it would take a research analyst to prepare the quarterly statements regarding public appearances as required by the regulation is ten minutes per analyst. The staff of the Commission believes that, on average, approximately 519 public appearances by research analysts occur per quarter,[67] or about 2,076 per year. Therefore, the Commission believes that the total annual burden for broker-dealers in hours of complying with the public appearance certification and disclosure requirements would be approximately 346 hours per year [(10 minutes x 2076 appearances) / 60 minutes].

In cases where the broker or dealer does not obtain a statement by the research analyst in connection with public appearances as described above, the broker-dealer must promptly notify its examining authority, designated pursuant to Section 17(d) of the Exchange Act and Rule 17d-2 thereunder, that the analyst did not provide certification in connection with public appearances. In addition, for 120 days following such notification, the broker-dealer must disclose in any research report it distributes authored by that analyst that the analyst did not provide certification specified in Rule 502(a) of Regulation AC. Further, broker-dealers must keep and maintain these records pursuant to Rule 17a-4(b)(4). Broker-dealers are also expected to have records that document the process they followed in producing each research analyst certification. The staff of the Commission believes that there will be few, if any, instances where a broker-dealer will provide notification to their examining authority, as analysts and their firms will have strong incentives to avoid having to make the type of disclosures required to be provided to their examining authority. Therefore, the total annual burden, in dollars, of complying with the public appearance certification requirements would be approximately $42,039 [346 hours x $121.50].

The regulation requires that the records of statements regarding public appearances be preserved in accordance with Exchange Act Rule 17a-4(b)(4). Exchange Act Rule 17a-4(b)(4) requires that any communication relating to a broker-dealer's business, including inter-office communications, must be kept for at least three years. In light of the existing record preservation requirement for brokers and dealers under Exchange Act Rule 17a-4(b)(4),[68] the staff of the Commission believes that any additional costs to preserve the records of the certifications required by the regulation would be minimal.

Rule 500 of Regulation AC includes a definition of "covered person," which limits the scope of the regulation's application. Rule 504 of Regulation AC requires a broker-dealer to notify its associated persons that issue research reports as to whether associated persons would meet the definition of "covered persons" under Regulation AC, and, therefore, be subject to the rule. Specifically, the broker-dealer must inform its associated persons whether the broker or dealer maintains and enforces written policies and procedures reasonably designed to prevent the broker or dealer or any of its

controlling persons, officers, or employees from influencing the activities of research analysts and the content of research reports prepared by associated persons. Broker-dealers must also inform its associated persons whether associated persons have any officers or employees in common with the broker or dealer who can influence the activities of research analysts or the content of research reports and, if so, the identity of those persons.

The staff has not obtained data on the amount of time it would take for broker-dealers to make the necessary determinations and to draft and provide the notification required under Rule 504 of Regulation AC. For PRA purposes, the below calculations represent the staff's estimates of the amount of time that would be required for broker-dealers to comply with Rule 504. The staff estimates that there are approximately 2,650 investment advisers that are associated with at least one broker-dealer. The staff estimates that it would take approximately one hour per year for each of the approximately 2,650 broker-dealers to determine whether it maintains and enforces written policies and procedures reasonably designed to prevent the broker or dealer or any of its controlling persons, officers, or employees from influencing the activities of research analysts and the content of research reports prepared by associated persons. The staff estimates that it would take approximately thirty minutes per year for each broker-dealer to determine whether its associated persons have any officers or employees in common with the broker or dealer who can influence the activities of research analysts or the content of research reports and, if so, the identity of those persons.[69]

The staff estimates that it would take fifteen minutes per year for each broker-dealer to draft and provide the required notification to its associated persons. The Commission staff expects that a compliance officer will likely be the employee primarily charged with making the necessary determinations, and drafting and providing the required notification. According to industry sources, in 2002, compliance officers, on average, earned approximately $82.00/per hour. Including 35% overhead, Commission staff estimates that the hourly pay rate for a compliance officer would be $110.70 per hour. Therefore, the Commission estimates that the annual burden for broker-dealers in hours of complying with the notification requirements would be approximately 4,638 hours [(2,650 x 105 minutes) / 60]. The staff estimates that the annual burden for broker-dealers of complying with the notification requirements in dollars would be approximately $513,427.00 [4,638 hours x $110.70].

Therefore, the Commission estimates that the regulation would result in a total annual burden in hours of approximately 38,954 hours [22,930 hours for broker-dealers to comply with the research report requirements + 11,040 hours for investment advisers to comply with the research report requirements + 346 hours for broker-dealers to comply with the public appearance requirements + 4,638 hours for broker-dealers to comply with the notification requirements], for a total annual cost in dollars of approximately $4,682,821 [$2,785,995 for broker-dealers to comply with the research report requirements + $1,341,360 for investment advisers to comply with research the report requirements + $42,039 for broker-dealers to comply with the public appearance requirements + $513,427 for broker-dealers to comply with the notification requirements].

IV. Costs and Benefits of Adopted Regulation Analyst Certification

To assist the Commission in evaluating the costs and benefits that may

result from adopting Regulation AC, the Commission sought comment on any potential costs, as well as any potential benefits, resulting from the proposal for investors, issuers, broker-dealers, other securities industry professionals, SROs, or others. The Commission also requested that commenters provide analysis and data to support their views. Regulation AC is part of an ongoing process by the Commission to address conflicts of interest affecting the production and dissemination of research by securities firms, and to provide increased disclosure to investors. Regulation AC includes a requirement that broker-dealers and covered persons include in research reports they publish certain certifications and disclosures about the analyst's views expressed in the research reports and any relationship between the analyst's compensation and the specific recommendations or views expressed. Regulation AC would also require broker-dealers to make, keep, and maintain records of research analyst certifications and disclosures in connection with public appearances. We are sensitive to the costs and benefits that result from our rules. The Commission initially identified certain costs and benefits relating to the proposals and encouraged commenters to discuss any additional costs or benefits. We discuss these costs and benefits below.

A. Costs

The Commission received letters from twenty-one commenters concerning Regulation AC. Only one commenter provided actual data to quantify the costs identified. This commenter believed that the estimates set forth in the proposing release were low primarily because the estimated number of research reports per year did not capture, among other things, reports by investment advisers and certain full-text reports.[70] The Commission modified its estimates in response to these comments.

The Commission also requested comment on how many public appearance certifications would likely be submitted to brokerage firms per quarter, and how many of those statements would be required to be provided to the firm's examining authority. One commenter believed that the estimate of the number of public appearances was too low, but did not provide specific data in support of its views.[71]

While Regulation AC may lead to some additional costs for brokers, dealers, and covered persons, we continue to believe that any costs should not be significant. In light of current requirements for broker-dealers under SRO rules, the Commission estimates that, beyond the paperwork costs described above, any additional costs to broker-dealers that would result from the required certifications and disclosures would be minimal. In the Proposing Release, the staff estimated that broker-dealers publish approximately 657,000 research reports per year. One commenter provided information that suggests that broker-dealers publish as many as 1,375,865 research reports per year.[72] Given the refined scope of Regulation AC, the staff believes that these two estimates represent a reasonable range with which to estimate research reports affected by the rule. Accordingly, the Commission estimates the total direct costs to be approximately $2.5 million to $4.7 million.[73] In addition, because the rule is minimally burdensome, the Commission believes that, beyond the paperwork costs described above, any additional costs to associated persons that would result from certifications and disclosures would be minimal.

Moreover, with respect to the compensation certifications and disclosures that are required by Regulation AC, brokers-dealers are already required to make certain disclosures regarding research analyst compensation under SRO

rules. For example, SRO rules currently require that firms disclose in research reports if the associated person preparing the report received compensation that is based upon (among other factors) the member's overall investment banking revenues.[74] Further, SRO rules prohibit members from offering favorable research to a company as consideration or inducement for the receipt of business or for compensation.[75] Additionally, Exchange Act Rule 17a-3(a)(19) currently requires broker-dealers to maintain a record of all agreements pertaining to the relationship between each associated person and the broker-dealer, including a summary of each associated person's compensation arrangement or plan.

In response to commenters' concerns, we modified the proposed rule text to include a definition of "covered person," which limits the scope of the regulation's application. Rule 504 of Regulation AC requires broker-dealers to notify its associated persons that issue research reports as to whether the broker-dealer maintains and enforces written policies and procedures reasonably designed to prevent the broker or dealer or any of its controlling persons, officers, or employees from influencing the activities of research analysts and the content of research reports prepared by the associated person, and to inform associated persons as to whether the associated person has any officers (or persons performing similar functions) or employees in common with the broker or dealer who can influence the activities of research analysts or the content of research reports and, if so, the identity of those persons. Broker-dealers may incur costs in providing this notification to each of its associated persons. As noted previously, the staff estimates that the paperwork costs for broker-dealers of complying with the notification requirements in dollars would be approximately $513,427.00. Any additional costs should not be significant in part because associated persons of an SRO member are required under SRO rules to provide prompt notice to his or her employer of employment with any other persons as a result of a business activity.[76]

With respect to public appearances, current SRO rules require analysts to make certain disclosures during public appearances, such as the member's or the analyst's ownership interests in the subject company. SRO rules also require analysts to disclose any other actual, material conflict of interest of which the research analyst knows, or has reason to know, at the time of the public appearance.[77]

Broker-dealers should already have in place procedures necessary to comply with many components of Regulation AC due to existing obligations under SRO rules, although these procedures might require some minor modifications to conform with Regulation AC. As noted previously, the Commission estimates that the annual paperwork costs in dollars of complying with the regulation would be approximately $4,682,821.

B. Benefits

We believe that investor confidence in the integrity of research has suffered because there is evidence that, in some cases, research analyst objectivity has been compromised due to, among other things, analysts' personal compensation and firms' investment banking relationships with issuers that are the subjects of research reports. Requiring research analysts to certify that the views expressed in research reports reflect their personal views, and requiring disclosure of information regarding whether analyst compensation is related to the specific recommendations made, should help bolster investor confidence in the quality of research. This, in turn, should

help increase investor confidence in the securities markets.

The Commission requested comment on whether the certification and disclosure requirements, if adopted, would promote investor confidence in the views expressed by research analysts and provide investors with useful information with which to evaluate potential biases. Ten commenters expressed support for Regulation AC. Generally, these commenters were of the view that Regulation AC would promote the integrity of research and investor confidence.[78] Three commenters did not agree that Regulation AC would advance investor protection and/or investor confidence to any significant degree.[79]

Regulation AC requires that broker-dealers and covered persons include certifications in research reports regarding the truthfulness of the views expressed in research reports and whether or not the analyst received compensation in connection with his or her specific recommendations or views. Many investors rely on the research reports and recommendations provided by their brokers and covered persons. To the extent that the Regulation AC requires disclosures that provide more transparency than provided by current regulation, these disclosures should provide investors with important information with which to determine the value of the research available to them.[80]

Regulation AC may result in an increase in the overall quality of the research available to the public because broker-dealers and covered persons would be in violation of Regulation AC when issuing research reports unless the reports include the required certifications and disclosures. The requirement that the research analyst (or analysts) primarily responsible for preparing the research report personally certify that the views expressed in the report accurately reflect his or her personal views creates an incentive for analysts to examine, even more carefully, the basis and foundations for his or her recommendations in preparing research reports.

Regulation AC may also result in an increase in the quality of research because of competitive reasons. Firms that publish research reports that do not contain certain analyst certifications will be in violation of the regulation, and firms whose research analysts' compensation is related to the specific recommendations or views provided in research reports (to the extent allowed by SRO rules) may lose some business to firms that are less conflicted. Regulation AC is intended to enhance investor confidence in the integrity of the research available to them. We believe that by requiring research analysts to certify as to the truthfulness of the views expressed in research reports, investor confidence in the securities markets should be enhanced, thereby leading to the benefit of more liquid and efficient markets. The Commission does not have data to quantify the value of the benefits described above. The Commission requested, but did not receive, comment on how it may quantify these benefits. The Commission also requested, but did not receive, comment concerning any benefits, not already identified, that may result from the adoption of Regulation AC.

V. Regulatory Flexibility Act Certification

Pursuant to Section 605(b) of the Regulatory Flexibility Act[81], the Commission certified that Regulation AC will not have a significant economic impact on a substantial number of small entities. This certification, including the reasons supporting the certification, were set forth in the Proposing Release.

The Commission solicited comments on the potential impact of Regulation AC on small entities in the Proposal. No comments were received that discussed the Regulatory Flexibility Act Certification. However, in response to other comments, the Commission has revised its estimates and believes that the total burden in hours required to comply with proposed Regulation AC would be approximately 5.78 hours per year, per small firm, as compared to the original estimate of two hours and two minutes per year, per small firm.

VI. Consideration of Burden on Competition, and Promotion of Efficiency, Competition and Capital Formation

Section 3(f) of the Exchange Act[82] requires us, when engaging in rulemaking where we are required to consider or determine whether an action is necessary or appropriate in the public interest, to consider whether the action will promote efficiency, competition, and capital formation. In addition, Section 23(a)(2)[83] of the Exchange Act requires the Commission to consider the impact any rule would have on competition. Further, the law requires that the Commission not adopt any rule that would impose a burden on competition not necessary or appropriate in furtherance of the purposes of the Exchange Act.

In the Proposing Release, the Commission solicited comment on the proposal's effect on competition, efficiency, and capital formation. Three commenters believed that Regulation AC would impose an inappropriate burden on competition.[84] One commenter asserted that the scope of Regulation AC was overly broad and would apply unnecessarily to, and be an onerous burden on, broker-dealer firms that are not subject to the conflicts the regulation is designed to address.[85] Another commenter asserted that Regulation AC may serve as a barrier to entry and an impediment to competition for firms seeking to provide an alternative to sell-side research.[86]

Regulation AC is intended to enhance investor confidence in the integrity of the research available to them. Further, we have modified the rule from the proposal and have limited the scope of its application. We believe that requiring broker-dealers and covered persons to include analyst certifications in research reports, as well as the other disclosures required by Regulation AC, should enhance investor confidence in the securities markets, thereby leading to a more efficient market.

The Commission has considered Regulation AC in light of the standards in Section 23(a)(2) and believes that it would not impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Exchange Act. As discussed above in the Cost-Benefit section, the Commission recognizes that Regulation AC may lead to some additional costs for broker-dealers and covered persons. On balance, we think that the application of Regulation AC is tailored to those situations where the conflicts are most likely to affect research. As such, we do not believe that the rule would create an unreasonable burden on competition. Further, we believe that providing the benefits that will result from the rule in those conflict-laden situations will further the purposes of the rule, including enhancing investor confidence in the market, thereby leading to a more efficient market.

VII. Statutory Authority

Regulation AC is being adopted pursuant to Sections 3, 15, 17, and 23 of

the Exchange Act and pursuant to Sections 17 and 19 of the Securities Act.

TEXT OF THE RULE

List of Subjects in 17 CFR Part 242

Securities.

For the reasons set out in the preamble, Title 17, Chapter II, of the Code of Federal Regulations is amended as follows.

Part 242 — REGULATIONS M, ATS, and AC and CUSTOMER MARGIN REQUIREMENTS FOR SECURITY FUTURES

1. The authority citation for part 242 continues to be read as follows:

Authority: 15 U.S.C. 77g, 77q(a), 77s(a), 78b, 78c, 78g(c)(2), 78i(a), 78j, 78k-1(c), 78l, 78m, 78mm, 78n, 78o(b), 78o(c), 78o(g), 78q(a), 78q(b), 78q(h), 78w(a), 78dd-1, 80a-23, 80a-29, and 80a-37.

2. The part heading for part 242 is revised as set forth above.

3. Part 242 is amended by adding Regulation AC, §§ 242.500 through 242.505 to read as follows:

Sec.

242.500 Definitions.

242.501 Certifications in connection with research reports.

242.502 Certifications in connection with public appearances.

242.503 Certain foreign research reports.

242.504 Notification to associated persons.

242.505 Exclusion for news media.

Regulation AC -- Analyst Certification

§ 242.500 Definitions.

For purposes of Regulation AC (§§ 242.500 through 242.505 of this chapter) the term:

Covered person of a broker or dealer means an associated person of that broker or dealer but does not include:

(1) An associated person:

(i) If the associated person has no officers (or persons performing similar functions) or employees in common with the broker or dealer who can influence the activities of research analysts or the content of research reports; and

(ii) If the broker or dealer maintains and enforces written policies and procedures reasonably designed to prevent the broker or dealer, any controlling persons, officers (or persons performing similar functions), and employees of the broker or dealer from influencing the activities of research analysts and the content of research reports prepared by the associated

person.

(2) An associated person who is an investment adviser:

(i) Not registered with the Commission as an investment adviser because of the prohibition of section 203A of the Investment Advisers Act of 1940 (15 U.S.C. 80b-3a); and

(ii) Not registered or required to be registered with the Commission as a broker or dealer.

Note to definition of covered person: An associated person of a broker or dealer who is not a covered person continues to be subject to the federal securities laws, including the anti-fraud provisions of the federal securities laws.

Foreign person means any person who is not a U.S. person.

Foreign security means a security issued by a foreign issuer for which a U.S. market is not the principal trading market.

Public appearance means any participation by a research analyst in a seminar, forum (including an interactive electronic forum), or radio or television or other interview, in which the research analyst makes a specific recommendation or provides information reasonably sufficient upon which to base an investment decision about a security or an issuer.

Registered broker or dealer means a broker or dealer registered or required to register pursuant to section 15 or section 15B of the Securities Exchange Act of 1934 (15 U.S.C. 78o or 78o-4) or a government securities broker or government securities dealer registered or required to register pursuant to section 15C(a)(1)(A) of the Securities Exchange Act of 1934 (15 U.S.C. 78o-5(a)(1)(A)).

Research analyst means any natural person who is primarily responsible for the preparation of the content of a research report.

Research report means a written communication (including an electronic communication) that includes an analysis of a security or an issuer and provides information reasonably sufficient upon which to base an investment decision.

Third party research analyst means:

(1) With respect to a broker or dealer, any research analyst not employed by that broker or dealer or any associated person of that broker or dealer; and

(2) With respect to a covered person of a broker or dealer, any research analyst not employed by that covered person, by the broker or dealer with whom that covered person is associated, or by any other associated person of the broker or dealer with whom that covered person is associated.

United States has the meaning contained in § 230.902(l) of this chapter.

U.S. person has the meaning contained in § 230.902(k) of this chapter.

§ 242.501 Certifications in connection with research reports.

(a) A broker or dealer or covered person that publishes, circulates, or

provides a research report prepared by a research analyst to a U.S. person in the United States shall include in that research report a clear and prominent certification by the research analyst containing the following:

(1) A statement attesting that all of the views expressed in the research report accurately reflect the research analyst's personal views about any and all of the subject securities or issuers; and

(2)(i) A statement attesting that no part of the research analyst's compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed by the research analyst in the research report; or

(ii) A statement:

(A) Attesting that part or all of the research analyst's compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed by the research analyst in the research report;

(B) Identifying the source, amount, and purpose of such compensation; and

(C) Further disclosing that the compensation could influence the recommendations or views expressed in the research report.

(b) A broker or dealer or covered person that publishes, circulates, or provides a research report prepared by a third party research analyst to a U.S. person in the United States shall be exempt from the requirements of this section with respect to such research report if the following conditions are satisfied:

(1) The employer of the third party research analyst has no officers (or persons performing similar functions) or employees in common with the broker or dealer or covered person; and

(2) The broker or dealer (or, with respect to a covered person, the broker or dealer with whom the covered person is associated) maintains and enforces written policies and procedures reasonably designed to prevent the broker or dealer, any controlling persons, officers (or persons performing similar functions), and employees of the broker or dealer from influencing the activities of the third party research analyst and the content of research reports prepared by the third party research analyst.

§ 242.502 Certifications in connection with public appearances.

(a) If a broker or dealer publishes, circulates, or provides a research report prepared by a research analyst employed by the broker or dealer or covered person to a U.S. person in the United States, the broker or dealer must make a record within thirty days after any calendar quarter in which the research analyst made a public appearance that contains the following:

(1) A statement by the research analyst attesting that the views expressed by the research analyst in all public appearances during the calendar quarter accurately reflected the research analyst's personal views at that time about any and all of the subject securities or issuers; and

(2) A statement by the research analyst attesting that no part of the research analyst's compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed by the research analyst in such public appearances.

(b) If the broker or dealer does not obtain a statement by the research analyst in accordance with paragraph (a) of this section:

(1) The broker or dealer shall promptly notify in writing its examining authority, designated pursuant to section 17(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78q(d)) and § 240.17d-2 of this chapter, that the research analyst did not provide the certifications specified in paragraph (a) of this section; and

(2) For 120 days following notification pursuant to paragraph (b)(1) of this section, the broker or dealer shall disclose in any research report prepared by the research analyst and published, circulated, or provided to a U.S. person in the United States that the research analyst did not provide the certifications specified in paragraph (a) of this section.

(c) In the case of a research analyst who is employed outside the United States by a foreign person located outside the United States, this section shall only apply to a public appearance while the research analyst is physically present in the United States.

(d) A broker or dealer shall preserve the records specified in paragraphs (a) and (b) of this section in accordance with § 240.17a-4 of this chapter and for a period of not less than 3 years, the first 2 years in an accessible place.

§ 242.503 Certain foreign research reports.

A foreign person, located outside the United States and not associated with a registered broker or dealer, who prepares a research report concerning a foreign security and provides it to a U.S. person in the United States in accordance with the provisions of § 240.15a-6(a)(2) of this chapter shall be exempt from the requirements of this regulation.

§ 242.504 Notification to associated persons.

A broker or dealer shall notify any person with whom that broker or dealer is associated who publishes, circulates, or provides research reports:

(a) Whether the broker or dealer maintains and enforces written policies and procedures reasonably designed to prevent the broker or dealer, any controlling persons, officers (or persons performing similar functions), or employees of the broker or dealer from influencing the activities of research analysts and the content of research reports prepared by the associated person; and

(b) Whether the associated person has any officers (or persons performing similar functions) or employees in common with the broker or dealer who can influence the activities of research analysts or the content of research reports and, if so, the identity of those persons.

§ 242.505 Exclusion for news media.

No provision of this Regulation AC shall apply to any person who:

(a) Is the publisher of any bona fide newspaper, news magazine or business or financial publication of general and regular circulation; and

(b) Is not registered or required to be registered with the Commission as a broker or dealer or investment adviser.

By the Commission.

Margaret H. McFarland
Deputy Secretary

Dated: February 20, 2003

Endnotes

1 17 CFR 242.500 through 505.

2 *See, e.g.*, Gretchen Morgenson, "NASD Sues Star Analyst Over Research," *The New York Times* at A1 (September 24, 2002).

3 On December 20, 2002, the Commission, New York Attorney General, North American Securities Administrators Association, New York Stock Exchange ("NYSE"), National Association of Securities Dealers ("NASD"), and state securities regulators announced an agreement in principle that, if approved by the Commission, would result in a settlement with major investment firms to resolve issues of conflicts of interest relating to the production of research reports. Securities and Exchange Commission Press Release No. 2002-179 (December 20, 2002).

4 Securities Exchange Act Release No. 45908 (May 10, 2002), 67 FR 34968 (May 16, 2002).

5 Securities Exchange Act Release No. 47110 (December 31, 2002)*, 68 FR 826 (January 7, 2003).* The Commission will consider action on these proposed rules after the close of the comment period, which is March 10, 2003.

6 Pub. L. 107-204 (2002).

7 Securities Exchange Act Release No. 46301 (August 2, 2002), 67 FR 51510 (August 8, 2002) ("Proposing Release").

8 *See* Letters to Jonathan G. Katz, Secretary, Commission, from: The Alliance in Support of Independent Research, dated September 20, 2002 ("Alliance"); Association for Investment Management and Research, dated September 30, 2002 ("AIMR"); The Bond Market Association, dated September 23, 2002 ("TBMA"); Charles Schwab &Co., Inc., dated September 23, 2002 ("Schwab"); Cleary, Gottlieb, Steen & Hamilton, dated September 12, 2002 ("Cleary"); Credit Suisse First Boston, dated September 23, 2002 ("CSFB"); David Norr Inc., dated August 16, 2002 ("David Norr"); Goldman Sachs, dated September 23, 2002 ("Goldman"); Investment Company Institute, dated September 23, 2002 ("ICI"); Investment Counsel Association of America, letters dated September 23, 2002 and January 13, 2003 ("ICAA"); Investorside Research Association, dated September 20, 2002 ("Investorside"); Karr Tuttle Campbell, dated September 27, 2002 ("Karr Tuttle"); Rupert Kenna, dated October 10, 2002; Merrill Lynch, dated September 18, 2002 ("Merrill"); North American Securities Administrators Association, Inc., dated September 23, 2002 ("NASAA"); Salomon Smith Barney, dated September 27, 2002 ("SSB"); Securities Industry Association, dated September 23, 2002 ("SIA"); Sullivan & Cromwell, dated September 23, 2002 ("Sullivan"); Thomson Financial, dated September 23, 2002; and Weiss Ratings, Inc., dated September 10, 2002 ("Weiss").

[9] "Covered person" is defined in Rule 500 of Regulation AC, and is discussed in detail below at II.A.2.

[10] Publish means to disseminate by any means, including though any third party.

[11] Regulation AC, 17 CFR 242.501(a). The Commission expects that the certifications will be included on the front page of the research report, or that the front page will specify the page or pages on which each certification is found. Disclosures and references to disclosures must be clear and prominent. Electronic research reports may utilize hyperlinks to this disclosure, provided that the first screen that the investor sees clearly and prominently labels the hyperlinks to the required disclosures. When hyperlinks are not possible (such as a report in PDF format), firms should follow the requirements for paper reports. *See* NYSE Information Memo No. 02-26 (June 26, 2002), and NASD Notice to Members 02-39 (July 2002).

[12] Communications relating to the certifications should be treated as being within the purview of Exchange Act Rule 17a-4(b)(4). *See* Exchange Act Rule 17a-4(b)(4), 17 CFR 240.17a-4(b)(4).

[13] *Cf. Hanly v. SEC*, 415 F.2d 589, 597 (2d Cir. 1969).

[14] *See* Alliance, AIMR, Cleary, Goldman, ICI, ICAA, SIA, SSB, Schwab, Sullivan, and Thomson Financial.

[15] *See, e.g.*, Cleary and SIA.

[16] *See, e.g.*, Cleary, ICAA, SSB, Sullivan, and Thomson Financial.

[17] *See* Rule 500 of Regulation AC (definition of "covered person").

[18] The proposed definition of "research analyst" referred to any natural person "principally" responsible for research reports; the adopted definition refers to any natural person "primarily" responsible. This modification clarifies that, whether or not a natural person is considered to be principally responsible for research reports as a job description, any natural person who is primarily responsible for the preparation of the content of any research report is a research analyst for the purposes of Regulation AC unless otherwise exempted.

[19] The term "person associated with a broker or dealer" is defined in Exchange Act Section 3(a)(18), 15 U.S.C. 78c(a)(18).

[20] Associated persons of a member are required under SRO rules to provide prompt notice to his or her employer of employment with any other persons as a result of a business activity. *See* NASD Rule 3030.

[21] 15 U.S.C. 80b-3a.

[22] Pub. L. No. 104-290, 110 Stat. 3416 (1996) (codified in scattered sections of the United States Code). Section 203A was designed to allow the Commission to better use its limited resources by concentrating its regulatory responsibilities on advisers with national businesses, and to reduce the burden to investment advisers of the overlapping and duplicative regulation existing prior to the enactment of NSMIA. *See* S. Rep. No. 293,

104th Cong., 2d Sess. 2-4 (1996). In conjunction with implementing NSMIA, the Commission amended several "prophylactic" anti-fraud rules under the Advisers Act to make them inapplicable to state-registered advisers because "application of these provisions to state-registered advisers is more appropriately a matter for state law." Investment Advisers Act Release No. 1633 (May 15, 1997), 62 FR 28112 (May 22, 1997).

23 Pursuant to authority under Advisers Act Section 203(a)(1)(A) the Commission adopted Advisers Act Rule 203A-1, which made SEC registration optional for certain investment advisers that have between $25 and $30 million of assets under management. *See* Advisers Act Rule 203A-1(a)(1), 17 CFR 275.203A-1(a)(1).

24 It is possible that a broker or dealer or covered person could provide a research report to a media entity intending that it be published. In that case, the report must be certified by the research analyst.

25 *See* CSFB, Goldman, NASAA, SSB, and TBMA. We note that the SOA and the SRO rules apply only to equity securities.

26 *See* SIA and Schwab.

27 We have focused on a group of fewer than fifteen persons in part because Congress made a determination that an investment adviser who, during the course of the preceding twelve months, has had fewer than fifteen clients and who, among other things, does not hold themselves out generally to the public as an investment adviser, does not have to register with the Commission as an investment adviser. *See* Advisers Act Rule 203(b)(3), 15 U.S.C. 80b-3(b)(3).

28 *See, e.g.*, SIA and SSB.

29 The Commission notes that any person not required to comply with the certification requirements of Regulation AC (*e.g.*, junior analysts) would nonetheless be subject to the antifraud provisions of the federal securities laws.

30 *See* Schwab and SIA.

31 *See* Schwab.

32 *See* AIMR, Goldman, SIA, and SSB.

33 The Commission believes that merely citing to the rule provision would not constitute an adequate notice.

34 *See* CSFB, Cleary, Goldman, SIA, SSB, and Schwab.

35 *See* CSFB, Cleary, SIA, SSB, and Schwab.

36 *See* SIA and SSB.

37 This certification must be in plain English. The Commission would expect that broker-dealers would be able to demonstrate that the combined certification in the report is accurate.

[38] *See* NYSE Information Memo No. 02-26 (June 26, 2002), and NASD Notice to Members 02-39 (July 2002).

[39] *See* Alliance, ICAA, ICI, Investorside, SIA, SSB, Sullivan, and Thomson Financial.

[40] *See, e.g.*, ICAA and ICI.

[41] *See* Investorside, SSB, Sullivan, and Thomson Financial.

[42] *See* NASAA.

[43] As discussed above, Regulation AC requires a broker-dealer to inform its associated persons as to whether or not it maintains and enforces the informational barriers described in Regulation AC.

[44] Regulation AC is directed at those regulated persons that prepare research reports, as well as persons associated with regulated persons who might be used if attempts were made to improperly circumvent the rule. *See also* Exchange Act Section 20(b), 15 U.S.C. 78t(b).

[45] *See* Alliance and Thomson Financial.

[46] *See, e.g.*, Schwab.

[47] *See, e.g.*, Cleary and Thomson Financial.

[48] As defined in the rule, for purposes of Regulation AC, "foreign security" means a security issued by a foreign company for which a U.S. market is not the principal trading market.

[49] *See, e.g.*, SIA and SSB.

[50] *See* SIA.

[51] *See* SIA and SSB.

[52] *See, e.g.*, Karr Tuttle, NASAA, SIA, and SSB.

[53] As the Commission stated in the Proposing Release, Regulation AC is not intended to create new duties under Section 10(b) of the Exchange Act. As a result, no private liability will arise from a broker, dealer, or associated person's failure to make the required disclosure, or make, keep, and maintain required records. However, Regulation AC is subject to the full range of the Commission's enforcement authority. With regard to the enforcement of Regulation AC by the SROs, nothing in Regulation AC is inconsistent with Exchange Act Rule 19g2-1. *See* 17 CFR 240.19g2-1.

[54] The use of a certification process echoes and is consistent with one approach employed in the Sarbanes-Oxley Act of 2002, which requires certifications by officers of corporations relating to issuers' financial statements. *See* Sarbanes-Oxley Act Sections 302 and 906, Pub. L. 107-204 (2002).

[55] *See, e.g.*, Securities Act Sections 17(a) and 17(b), 15 U.S.C. 77q; Exchange Act Section 10(b), 15 U.S.C. 78j(b), and Rule 10b-5, 17 CFR

240.10b-5.

[56] *See, e.g.*, Securities Act Section 17(a), 15 U.S.C. 77q(a); Exchange Act Rule 10b-5, 17 CFR 240.10b-5; Exchange Act Section 15(c)(1)(A), 15 U.S.C. 78*o*(c)(1)(A); and Exchange Act Rule 15c1-2(b), 17 CFR 240.15c1-2.

[57] *See* Securities Exchange Act Release No. 45908 (May 10, 2002), 67 FR 34968, 34977 (May 16, 2002); Proposing Release at 51512; *Cf. Hanly*, supra, note 13, at 597. *See also In the Matter of Robertson Stephens, Inc.*, Administrative Proceeding File No. 3-11003 (January 9, 2003) (settled fraud action against broker-dealer where Commission found that a research analyst employed by the broker-dealer issued recommendations about a public company that were inconsistent with his privately communicated beliefs about the company.)

[58] *See, e.g.*, Goldman and Merrill.

[59] *See, e.g.*, Cleary, SIA, SSB, and Sullivan.

[60] 44 U.S.C. Section 3501 *et seq*.

[61] 44 U.S.C. Section 3507(d) and 5 CFR 1320.11.

[62] Thomson Financial asserted in its comment letter that the Commission's cost estimate in the Proposing Release was too low. Thomson Financial noted that the Commission cited data from Thomson Financial First Call and estimated that broker-dealers publish 657,000 research reports per year. Thomson Financial asserted that, while this estimate may accurately reflect equity research on U.S. securities transmitted via First Call Notes, it did not capture fixed-income research, research on non-U.S. equities or full-text reports transmitted through First Call Research Direct. Thomson Financial asserted that, when these additional sell-side reports are accounted for, the total exceeds 2 million reports a year. Thomson Financial suggested that the compliance costs for sell-side firms could run as high as $4,116,784.50.

[63] After further consultation with Thomson Financial, they have revised their total estimated number of research reports per year for 2001 to range between 1,375,865 and 1,540,150. The staff believes that the overall calculations are over-inclusive and possibly duplicative. As a result, we are basing our estimates on the lower-end of the range of the number of research reports per year. The staff believes that this estimate continues to be conservative.

[64] The estimated total annual burden in dollars for broker-dealers to comply with the research report certification and disclosure requirements would be approximately $3,118,642.00 if calculated using the high-end of the estimated range for the number of research reports.

[65] We believe that including all SEC registered investment advisers in calculating the paperwork burden as to covered persons is over-inclusive as to investment advisers, and that this estimate is therefore sufficient to account for other types of entities who would meet the definition of "covered person."

[66] The estimated total annual burden in dollars for SEC registered investment advisers to comply with the research report certification and disclosure requirements would be approximately $1,501,518.00 if calculated using the

high-end of the estimated range for the number of research reports.

67 519 is approximately 10% of the estimated 5,186 research analysts employed in the U.S., which is based on information provided by Nelson Information. One commenter believes that this estimate is low, but did not provide specific data in support of its views. *See* Thomson Financial.

68 OMB Control No. 3235- 0279.

69 Broker-dealers should already have mechanisms in place to determine whether such persons exist and, if so, the identity of those persons because of NASD Rule 3030. *See* NASD Rule 3030.

70 *See* Thomson Financial.

71 *Id.*

72 *See* Thomson Financial and footnote 63 for a discussion of revisions to the original estimate.

73 The total burden range of approximately $2.5 million to $4.7 million is obtained by applying both the low and the high research report estimates. Costs are proportionate to the number of research reports assumed to be issued each year. For purposes of the Paperwork Reduction Act analysis, we used the estimate of 1,375,865 research reports to obtain the high end of the burden range. If we instead substitute the low estimate of 657,000 research reports in place of the high estimate, the low end of the burden range is approximately $2.5 million. The low research report estimate is approximately 48% of the high estimate and the resulting total annual cost burden is approximately $2.5 million [$1,337,278 for broker-dealers to comply with the research report requirements + $643,853 for investment advisers to comply with the research report requirements + $42,039 for broker-dealers to comply with the public appearance requirements + $513,427 for broker-dealers to comply with the notification requirements = $2,536,596].

74 NASD 2711 (h)(2)(A)(i); NYSE 472 (k) (2).

75 NASD Rule 2711(e); NYSE Rule 472(g).

76 *See* NASD Rule 3030.

77 NASD Rule 2711(h); NYSE 472(k)(1).

78 *See* AIMR, CSFB, Goldman, ICAA, ICI, Merrill, SIA, SSB, Schwab, and TBMA.

79 *See* David Norr, NASAA, and Thomson Financial.

80 *See* Securities Exchange Act Release No. 45908 (May 10, 2002), 67 FR 34968 (May 16, 2002).

81 5 U.S.C. 605(b).

82 15 U.S.C. Section 78c(f).

83 15 U.S.C. Section 78w(a)(2).

[84] *See* Alliance, Investorside, and Thomson Financial.

[85] *See* Alliance.

[86] *See* Investorside.

http://www.sec.gov/rules/final/33-8193.htm

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Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation

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Regulation FD made analysts less dependent on insider information and diminished analysts' motives to inflate their forecasts. The Global Research Analyst Settlement had an even bigger impact on analyst behavior: The mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. These results are similar for all analysts.

Our investigation of the impact of recent changes in regulation on analysts' forecasting behavior follows a number of studies that argued that analysts were motivated to produce research reports that did not reflect their true opinions. Analysts tended to make excessive "buy" recommendations and inflated earnings forecasts for several reasons, two of which gained considerable attention from regulators in the United States. First, analysts may have felt compelled to favor managers in covered companies in order to gain privileged access to information flow (Lim 2001). Second, although analysts are supposed to provide investors with accurate and truthful research reports, conflicts of interest could occur because analysts' compensation was tied to profits generated from investment banking business and brokerage commissions (Lin and McNichols 1998; Carleton, Chen, and Steiner 1998).

In the early part of the first decade of this century, in an effort to restore public confidence in U.S. capital markets, U.S. regulators enacted several rules and regulations, prosecuted analysts whose research reports were tainted by conflicts of interest, and fined banks that failed to prevent research analysts' conflicts of interest. Two of the main regulatory developments during this period were (1) Regulation Fair Disclosure (Reg FD), which became effective on 23 October 2000, and (2) the Global Research Analyst Settlement (Global Settlement), which was announced on 20 December 2002.[1]

Although the primary goals of these two regulatory actions are different, they both have the potential to improve the quality of analyst forecasts. One of the stated goals of Reg FD is to prohibit private communication between companies and analysts, thereby helping to level the playing field so that market participants can have equal access to information and making analysts less dependent on such communication. In prohibiting companies from selectively disclosing private information to analysts, Reg FD may reduce analyst forecast bias by eliminating the incentive for analysts to inflate their earnings forecasts in order to gain access to insider information.

The Global Settlement is an important enforcement agreement between U.S. regulators and 12 large investment banks (the Big-12 banks) designed to eliminate research analysts' conflicts of interest. If successful, the Global Settlement should reduce optimistic bias in analyst forecasts.

Our study considered whether these two actions by U.S. regulators reduced the bias in analysts' earnings forecasts documented in previous studies. We focused on annual earnings forecast bias for several reasons. First, investors may use analyst forecasts to form expectations of earnings and cash flows, both of which are important inputs for stock valuation models. Inflated earnings forecasts can drive stock prices above their fair values if investors fail to adjust for the bias.[2]

Second, given the flurry of new regulations, regulators clearly consider analyst behavior an important factor in maintaining investor confidence in financial markets. Regulation is costly because of the significant expenses associated with analyzing problematic situations and developing remedies. Moreover, restrictions and reporting requirements imposed on various market participants result in ongoing compliance costs. These costs can be justified only if the new regulations help reduce analysts' conflicts of interest and thereby generate an important benefit for financial markets.

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Third, most studies that have examined the impact of Reg FD and the Global Settlement on analyst behavior focused on forecast accuracy and forecast dispersion (Bailey, Li, Mao, and Zhong 2003; Agrawal, Chadha, and Chen 2006).[3] These aspects of analyst behavior, however, are little affected by conflicts of interest, the focus of our study.

Other studies have examined forecast bias. Clarke, Khorana, Patel, and Rau (2006) found that the Global Settlement had no impact on relative bias in analyst forecasts. Focusing on the impact of Reg FD on bias in quarterly earnings forecasts between October 1999 and December 2001, Mohanram and Sunder (2006) found that these forecasts became more optimistic after Reg FD but attributed the increase to unexpectedly low realized earnings during the 2001 recession. Our longer study period (1996–2006) allowed us to control for macroeconomic conditions in our regression analysis. Furthermore, we examined longer-term (up to 24 months) earnings forecasts in which the forecast bias is more apparent (Richardson, Teoh, and Wysocki 2004). Although Herrmann, Hope, and Thomas (2008) found some evidence of decline in forecast bias following Reg FD, they focused on internationally diversified companies only; we examined all U.S. companies, and our primary focus was on changes in forecast bias after the Global Settlement.

Lastly, the ability of analysts to forecast earnings accurately can be easily and straightforwardly verified because actual earnings are observed at the end of the forecast period. Barber, Lehavy, McNichols, and Trueman (2006) studied the change in distribution of stock recommendations made from 1996 to 2003. They found that the percentage of buys decreased starting in mid-2000.[4] How unbiased the new distribution of stock recommendations is, however, remains uncertain. But we know that the bias should be zero at the aggregate level when analysts make their forecasts on the basis of their true opinions.

Institutional Background

Historically—and especially before recent regulations—analysts have tended to make unduly optimistic earnings forecasts. In this section, we discuss the possible reasons for this optimistic bias and the potential impacts of the recent regulations on such bias.

Why Do Analysts Make Overoptimistic Earnings Forecasts? A number of studies have documented that analysts regularly make overoptimistic earnings forecasts (Brown 1997; Chopra 1998; Beckers, Steliaros, and Thomson 2004). Optimistic bias tends to be larger for longer-term forecasts and smaller for forecasts made closer to the earnings announcement date. This phenomenon is usually referred to as the walk-down trend (Richardson, Teoh, and Wysocki 2004). Several explanations have been offered for analyst optimism.

First, analysts may be influenced by conflicts of interest if their compensation is tied to investment banking fees and brokerage commissions. Lin and McNichols (1998) found that analysts affiliated with underwriters make more favorable stock recommendations and long-term earnings growth forecasts than analysts not so affiliated. Agrawal and Chen (2005) discovered that optimism in long-term earnings growth forecasts is high when analysts work for financial institutions whose revenues come mainly from brokerage business. Carleton, Chen, and Steiner (1998) found that stock recommendations made by brokerage firms are more optimistic than those of nonbrokerage firms. Using Australian data, Jackson (2005) noted that optimistic analysts generate more trades for their brokerage firms than do less optimistic analysts. Chan, Karceski, and Lakonishok (2007) showed that analysts' earnings forecasts are influenced by their desire to win investment banking clients. Doukas, Kim, and Pantzalis (2005) reported that stocks with excess analyst coverage yield lower future returns, consistent with the conflict-of-interest hypothesis. Hong and Kubik (2003) found that brokerage houses reward optimistic analysts; optimistic analysts at low-status brokerage houses are more likely to move up to higher-status brokerage houses than are less optimistic analysts.

Second, analysts may feel compelled to maintain good relations with company management in order to gain access to insider information that can help improve the accuracy of their forecasts (Lim 2001). Third, analysts may tend to cover stocks for which they have positive views and drop or avoid stocks for which they have negative views, which can induce a self-selection bias (McNichols and O'Brien 1997). Fourth, analysts may have a cognitive bias that leads them to overreact to good earnings information and underreact to bad earnings information (Easterwood and Nutt 1999; Nutt, Easterwood, and Easterwood 1999). Finally, the walk-down trend may be driven by the "earnings guidance game," in which analysts issue optimistic forecasts at the start of the fiscal year and then revise their estimates until the company can beat the forecast at the earnings announcement date (Richardson, Teoh, and Wysocki 2004).

Recent Regulations. Before Reg FD, analysts and institutional investors often had an informational advantage over small investors through private communications with management and conference calls in which company managers discussed past performance and provided guidance on future prospects. Such timely information gave these investment professionals an unfair advantage that allowed them to trade stocks profitably at the expense of uninformed investors.

To gain access to this information flow, analysts may have had to maintain good relations with insiders by making optimistic forecasts and buy recommendations in their research reports. Analysts' excessively optimistic views of the stocks were misleading and contributed to the deterioration of investor confidence in capital market integrity. Through Reg FD, which was introduced in October 2000, the U.S. SEC intended to improve fairness and restore public confidence in the markets by requiring U.S. public companies to disclose material information simultaneously to all market participants.

Other sources of conflicts of interest, however, remained unaddressed by Reg FD. For instance, analysts could be pressured to make optimistic forecasts and buy recommendations in order to favor investment banking clients and generate trading volume. The SEC and such self-regulatory organizations (SROs) as the National Association of Securities Dealers (NASD; now the Financial Industry Regulatory Authority [FINRA]) and the NYSE paid significant attention to this issue and introduced a number of new rules and regulations to curb the negative consequences of these conflicts of interest.

The Sarbanes–Oxley Act of 2002 (SOA), also known as the Public Company Accounting Reform and Investor Protection Act of 2002, became law on 30 July 2002. The SOA is a broad piece of legislation that covers various business practices, including auditor independence, corporate responsibility, enhanced financial disclosure, analysts' conflicts of interest, and corporate and criminal fraud accountability. The SOA amended the Securities Exchange Act of 1934 by creating Section 15D, which requires FINRA and the NYSE to adopt rules reasonably designed to address research analysts' conflicts of interest.

To comply with the SOA, the NASD released Rule 2711 (Research Analysts and Research Reports) and the NYSE amended its Rule 351 (Reporting Requirements) and Rule 472 (Communications with the Public). Most provisions of these rules went into effect on 9 July 2002. These rules mitigate analysts' conflicts of interest by separating research analysts from the influence of the investment banking and brokerage businesses. Research analysts' compensation can no longer be tied to the performance of these businesses. In addition, analysts are restricted from personal trading in the stocks they cover.

On 6 February 2003, the SEC adopted Regulation Analyst Certification (Reg AC).[5] Reg AC provides guidelines for proper disclosure of potential conflicts of interest of sell-side analysts, including their association with investment banking clients and the structure of their compensation.

Regulatory objectives have also received support from rigorous enforcement actions. Following a joint investigation by the SEC, NASD, NYSE, and New York State Attorney General, 10 large U.S. and multinational investment banks agreed to pay a fine of $1.435 billion in the Global Research Analyst Settlement for their failure to adequately address research analysts' conflicts of interest. Announced on 20 December 2002, the terms of the Global Settlement initially covered 10 banks.[6] The final agreement was announced on 28 April 2003. Two more banks reached settlements on 26 August 2004.[7] The Global Settlement and the SRO rules share the same spirit in that their mutual objective is to eliminate analysts' conflicts of interest.

The introduction of these rules and regulations allows us to differentiate among the alternative explanations for analyst forecast bias proposed in the literature. First, a reduction in forecast bias after Reg FD would support the argument that analysts were overoptimistic owing to their need for insider information, especially if such a reduction were stronger for informationally more opaque companies. Second, a reduction in bias after the Global Settlement and Rule 2711 would be consistent with the hypothesis that analyst behavior was unduly influenced by conflicts of interest.[8] In contrast, self-selection and cognitive biases may exist even in a world without conflicts of interest. Therefore, if these biases are the main reasons for analysts' overoptimistic forecasts, then these regulatory changes should have no effect on forecast bias.[9]

Sample and Variables

We downloaded sell-side analysts' earnings forecasts for fiscal year-end dates between 1996 and 2006 from the Detail file of the I/B/E/S database. We used forecasts for current- and subsequent-year earnings per share (EPS), which are made for the upcoming and following years' earnings announcement dates.[10] **Figure 1** illustrates the timeline of analyst forecasts. The earliest analyst forecasts for a specific fiscal year-end EPS are made 24 months before the forecast fiscal year-end (in forecast month –23). For each EPS, analysts can

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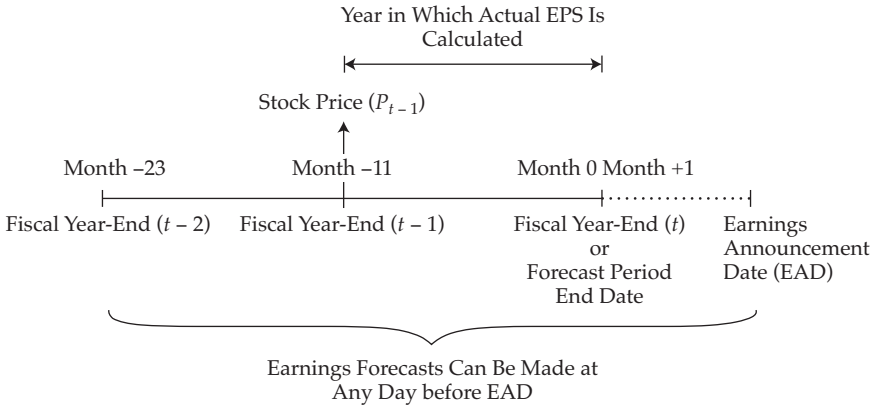
Figure 1. Timeline of Analyst Forecasts



make multiple forecasts over the course of the next 24 months. Some analysts may continue to make forecasts after the forecast fiscal year ends because companies announce their annual earnings after a delay of several months. Because the length of the EPS announcement delay could be affected by how high or low the realized EPS is relative to the consensus, we retained only those forecasts made no more than one month after the forecast fiscal year-end (in forecast month +1), which left us with a total of 2,297,792 forecasts.

For each forecast, I/B/E/S provides actual earnings, forecast date, forecast period (fiscal year) end, earnings announcement date, analyst code identity, broker code identity, and number of analysts used for consensus calculation.[11] We used the I/B/E/S Broker Translation file to convert broker codes into brokers' names, which we used to identify analysts who worked for the Big-12 banks. Stock prices are from the I/B/E/S Summary file.[12] We downloaded real GDP growth rates from the website of the U.S. Bureau of Economic Analysis. We downloaded SIC codes from the CRSP monthly file.

We defined analyst forecast bias, the focus of our analysis, as the average analyst forecast error and calculated it as follows:

$$Bias_{j,t,m} = 100\left(F_{j,t,m} - A_{j,t}\right)/P_{j,t-1}, \quad (1)$$

$$F_{j,t,m} = \frac{1}{I_{j,t,m}} \sum_{i=1}^{I} F_{j,t,m,i}, \quad (2)$$

and

$$F_{j,t,m,i} = \frac{1}{K_{j,t,m,i}} \sum_{k=1}^{K} F_{j,t,m,i,k}, \quad (3)$$

where

$A_{j,t}$ = the actual earnings per share for company j in fiscal year t

$F_{j,t,m,i}$ = the average of annual earnings forecasts for fiscal year-end t of company j, made in month m by analyst i

$K_{j,t,m,i}$ = the number of forecasts made in month m by the same analyst i for the same company j and fiscal year t

$I_{j,t,m}$ = the number of analysts making forecasts in month m for company j and fiscal year t

$P_{j,t-1}$ = the stock price of company j one year before the fiscal year-end t[13]

Note that all EPS forecasts made for the same company and the same fiscal year are normalized by the same stock price. Using the same stock price as the denominator guarantees that any changes in forecast bias across forecast months (m) are the result of changes in analyst forecasts, not of changes in the stock price. In our calculations according to Equations 1–3, we used only new forecasts made in month m. Stale forecasts from earlier months (m – 1, etc.) were not carried over into month m. In other words, each forecast participated in the calculation of the forecast bias only once, in the month in which the forecast was made. In our sample, an average analyst made 4.5 forecasts for each annual EPS. Because for each annual EPS we tracked 25-month forecasts (from month –23 to month +1), the implication is that an average analyst in our sample made a forecast for each covered company about once every six months.

To minimize the influence of outliers and misreported data in our analysis, we replaced with missing values any extreme observations of forecast bias, company size, market-to-book ratio, the number of stocks, and the number of industry analysts following.[14] We dropped from the sample all forecasts made in October 2000 and December 2002 (1.5 percent of our sample) and observations with missing values of any relevant variable. We were

left with 1,586,000 individual analyst forecasts, which we used to calculate 434,268 average forecast errors. For each fiscal year and for each of our 7,315 sample companies, our sample contained up to 25 monthly observations of forecast bias ($Bias_{j,t,m}$).

Table 1 reports the summary statistics for the overall sample of 434,268 observations and for each of the three subperiods. The period before Reg FD represents 53 percent of our sample observations, with the period between Reg FD and the Global Settlement and the period after the Global Settlement representing 18 percent and 29 percent of the sample observations, respectively. The mean forecast bias across all sample observations is 1.39 percent of stock price. This result is consistent with prior evidence that analysts' forecasts are optimistically biased (Brown 1997; Chopra 1998). No significant difference exists between the mean forecast bias before Reg FD (1.72) and the mean forecast bias between Reg FD and the Global Settlement (1.97). The mean forecast bias is more than four times smaller after the Global Settlement (0.41), with the difference statistically significant at the 1 percent level.

The average market capitalization of companies in our sample was $4.5 billion, and the average market-to-book ratio was 3.57. On average, 8.41 analysts covered a company in any particular month. The analysts in our sample worked for brokers that, on average, each employed 65.7 analysts. A typical analyst followed 16.30 stocks from 4.78 industries and, at the time of the forecast, had been in the I/B/E/S database for 6.24 years and making forecasts for the covered stock for 2.5 years. Around 17 percent of forecasts were made for companies with negative earnings, and 36 percent of forecasts were made for companies whose earnings were declining relative to earnings in the prior fiscal year.

Test Results

In this section, we present the results of the univariate tests and of the regression analysis of the effects of Reg FD and the Global Settlement on bias in analyst forecasts.

Univariate Results by Forecast Month. **Table 2** presents the median forecasts by the month in which the forecasts were made and by the fiscal year for which they were made. The numbers in the leftmost column represent the month (relative to the fiscal year-end) of the forecast. The numbers in the top row represent the fiscal years for which the

Table 1. Summary Statistics

				Number of Observations			Mean		
Description	Variable	Number of Observations	Mean	Before Reg FD	Between Reg FD and GS	After GS	Before Reg FD	Between Reg FD and GS	After GS
Forecast bias	Bias	434,268	1.39	231,096	77,305	125,867	1.72	1.97	0.41
Reg FD indicator	RegFD	434,268	0.18	231,096	77,305	125,867	0.00	1.00	0.00
Global Settlement indicator	Glob	434,268	0.29	231,096	77,305	125,867	0.00	0.00	1.00
Company characteristics									
Analyst coverage	NumA	434,268	8.41	231,096	77,305	125,867	8.21	8.23	8.88
Market cap ($ millions)	CompanySize	434,268	4,470.00	231,096	77,305	125,867	3,480.00	5,250.00	5,800.00
Market-to-book ratio	MB	434,268	3.57	231,096	77,305	125,867	3.78	3.47	3.23
Negative EPS	EPSLoss	434,268	0.17	231,096	77,305	125,867	0.16	0.26	0.14
Declining EPS	EPSDecline	434,268	0.36	231,096	77,305	125,867	0.37	0.45	0.27
Litigation	Litigation	434,268	0.27	231,096	77,305	125,867	0.25	0.30	0.27
Labor intensive	Labor	434,268	0.61	231,096	77,305	125,867	0.60	0.63	0.63
Analyst characteristics									
Company-specific experience	YearStk	434,268	2.50	231,096	77,305	125,867	2.55	2.43	2.46
General experience	YearIBES	434,268	6.24	231,096	77,305	125,867	6.45	6.19	5.87
No. of stocks covered	NumStk	434,268	16.30	231,096	77,305	125,867	18.18	14.31	14.06
No. of industries covered	NumInd	434,268	4.78	231,096	77,305	125,867	5.46	4.15	3.93
Broker size	BrokerSize	434,268	65.70	231,096	77,305	125,867	54.98	89.03	71.06

Note: This table presents the summary statistics for the overall sample and for the three subperiods.

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Table 2. Forecast Bias by Fiscal Year and Forecast Month

	Forecast Period End Year										
Month	96	97	98	99	00	01	02	03	04	05	06
–23	0.1	0.4	1.4	1.6	–0.3	1.9	2.3	1.2	–0.2	–0.3	–0.3
–22	0.3	0.5	0.9	1.3	0.5	2.2	2.7	1.3	0.0	–0.1	0.0
–21	0.3	0.5	1.1	1.6	0.5	2.1	2.6	1.3	0.0	0.0	0.2
–20	0.4	0.5	1.1	1.3	0.6	2.2	2.2	1.4	–0.1	0.0	0.0
–19	0.5	0.7	1.1	1.6	0.5	2.1	2.1	1.3	–0.1	0.0	0.1
–18	0.5	0.4	1.2	1.4	0.6	2.1	1.8	1.1	–0.2	0.0	0.1
–17	0.4	0.4	1.2	1.1	0.5	2.1	1.4	1.0	–0.2	0.0	0.1
–16	0.4	0.5	1.3	1.3	0.6	2.0	1.5	1.1	–0.1	0.0	0.2
–15	0.4	0.4	1.1	0.8	0.4	1.7	0.9	0.8	–0.3	0.0	0.2
–14	0.4	0.3	0.9	0.6	0.4	**FD**	0.6	0.4	–0.2	0.0	0.1
–13	0.4	0.3	1.0	0.6	0.4	1.5	0.5	0.3	–0.2	0.1	0.2
–12	0.3	0.2	0.8	0.4	0.3	1.6	0.4	**GS**	–0.2	–0.1	0.1
–11	0.3	0.3	0.8	0.3	0.1	1.3	0.3	0.1	–0.1	0.0	0.1
–10	0.2	0.2	0.5	0.1	0.2	1.1	0.2	0.0	–0.1	–0.1	–0.1
–9	0.2	0.2	0.6	0.1	0.1	1.1	0.2	0.0	–0.1	0.0	–0.1
–8	0.1	0.1	0.5	0.1	0.1	0.7	0.2	–0.1	–0.1	–0.1	–0.1
–7	0.1	0.0	0.5	0.1	0.1	0.6	0.2	–0.1	0.0	0.0	0.0
–6	0.1	0.1	0.4	0.0	0.1	0.5	0.2	–0.1	–0.1	–0.1	0.0
–5	0.0	0.0	0.2	0.0	0.0	0.2	0.1	–0.1	0.0	–0.1	0.0
–4	0.0	0.0	0.1	0.0	0.0	0.2	0.1	–0.1	0.0	0.0	0.0
–3	0.0	0.0	0.1	0.0	0.0	0.1	0.0	–0.1	–0.1	0.0	0.0
–2	0.0	0.0	0.0	0.0	**FD**	0.0	0.0	–0.1	–0.1	0.0	0.0
–1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	–0.1	0.0	0.0	–0.1
0	0.0	0.0	0.0	–0.1	0.0	0.0	**GS**	–0.1	0.0	0.0	–0.1
1	0.0	–0.1	0.0	–0.1	–0.1	0.0	0.0	–0.1	–0.1	–0.1	–0.3
Median bias	0.2	0.2	0.8	0.3	0.1	1.2	0.4	0.0	–0.1	0.0	0.0
Mean bias	1.2	1.1	1.8	2.2	1.4	3.0	2.1	1.6	0.1	0.5	0.3
Mean forecast	6.2	5.3	4.6	5.1	5.3	3.7	3.0	4.0	4.4	4.2	5.0
Mean actual earnings	5.0	4.1	2.8	2.9	3.9	0.7	0.9	2.4	4.2	3.7	4.7
Mean stock return (%)	0.2	0.2	0.0	0.2	0.0	0.0	–0.2	0.6	0.2	0.1	0.2
GDP (%)	3.7	4.5	4.2	4.5	3.7	0.8	1.6	2.5	3.9	3.2	3.3

Notes: *Forecast bias* is the difference between the mean of all forecasts made in a particular month for a particular company and a particular fiscal year and the realized EPS, scaled by the stock price and multiplied by 100. *Forecast period end year* is the fiscal year for which the forecast was made. *Month* is the month of the forecast relative to the fiscal year-end. *FD* is the month in which Reg FD became effective (October 2000). *GS* is the month in which the Global Settlement was announced (December 2002). Stock returns were calculated from our samples.

forecasts were made. For example, forecasts made in September 2000 for the fiscal year ended December 2000 (i.e., three months before the fiscal year-end) are in row –3 and column 00. The two solid lines separate the forecasts made before and after Reg FD and the forecasts made before and after the Global Settlement. The six bottom rows present forecast bias for each fiscal year averaged across all forecast months, along with the realized earnings per share, average forecasts, annual stock returns, and real GDP growth rates.[15] To align fiscal year-end dates with annual variables, such as real GDP growth rates, we used only forecasts for companies with December fiscal year-ends.

For each year before the Global Settlement, the median forecast errors are significantly positive. Furthermore, for each year before the Global Settlement, we observe the walk-down trend with forecast bias steadily declining as forecasts are made closer to the fiscal year-end. After the Global Settlement, we observe a significant drop in the forecast bias. The results show a total absence of bias in the median forecast errors for 2004–2006 (–0.1 percent, 0.0 percent, and 0.0 percent, respectively). The walk-down trend in median forecast errors is also practically nonexistent for fiscal years 2004–2006.

These results suggest that analysts' conflicts of interest indeed led to excess optimism in earnings forecasts before the Global Settlement and that the Global Settlement has been effective in neutralizing analysts' conflicts of interest. Alternative interpretations of the forecast bias, such as self-selection, cognitive bias, and need for insider information, cannot explain these findings because the Global Settlement should have no effect on these factors.

Unusually high stock valuations and/or realized earnings, rather than less optimistic forecasts, could be responsible for the decline in the average forecast errors after the Global Settlement. A quick look at the actual and forecasted EPS, stock returns, and real GDP growth rates before and after the Global Settlement, however, does not seem to support this idea. Neither aggregate economic performance nor stock valuations seem to be out of the ordinary in the post-settlement years. The actual earnings, stock returns, and GDP growth rates seem to be unusually low in the period between Reg FD and the Global Settlement. We controlled for the effects of these and other potentially relevant factors by examining the effects of Reg FD and the Global Settlement in a regression framework.

Regression Analysis. To examine how Reg FD and the Global Settlement affect bias in analyst forecasts while controlling for the confounding effects of company and analyst characteristics, as well as economic conditions, we estimated the following regression model:

$$\begin{aligned} Bias_{j,t,m} &= \alpha_0 + \alpha_1 RegFD_{t,m} + \alpha_2 Glob_{t,m} + \alpha_3 NumA_{j,t,m} \\ &+ \alpha_4 CompanySize_{j,t,m-1} + \alpha_5 MB_{j,t,m-1} \\ &+ \alpha_6 YearStk_{j,t,m} + \alpha_7 YearIBES_{j,t,m} \\ &+ \alpha_8 NumStk_{j,t,m} + \alpha_9 NumInd_{j,t,m} \\ &+ \alpha_{10} BrokerSize_{j,t,m} + \alpha_{11} EPSLoss_{j,t} \\ &+ \alpha_{12} EPSDecline_{j,t} + \alpha_{13} Litigation_j \\ &+ \alpha_{14} Labor_{j,t,m-1} + \alpha_{15} ActualGDP_t \\ &+ \alpha_{16} UnexpectedGDP_{t,m} + \beta Month_m + \gamma Year_t \\ &+ \delta_j \sum DCompany_j + \varepsilon_{j,t,m}. \end{aligned} \quad (4)$$

In Equation 4, $Bias_{j,t,m}$ is the mean forecast error for all forecasts for company j made in month m relative to the end of fiscal year t, calculated according to Equations 1–3. $RegFD_{t,m}$ equals 1 for forecasts made between 23 October 2000 and 20 December 2002. $Glob_{t,m}$ equals 1 for forecasts made after 20 December 2002. A negative sign for the coefficient of $RegFD_{t,m}$ or $Glob_{t,m}$ would indicate a decline in the bias following, respectively, Reg FD and the Global Settlement.

Lim (2001) argued that the forecast bias is higher when a company's information environment is less transparent—for example, when the company is small and has less analyst coverage. Beckers, Steliaros, and Thomson (2004) showed that the number of analysts following a stock affects the accuracy of the consensus earnings forecast. Hence, we used analyst coverage and company size as proxies for the degree of information transparency. Analyst coverage, $NumA_{j,t,m}$, is defined as the number of outstanding forecasts used in I/B/E/S's monthly consensus calculation. Analyst coverage represents the number of analysts following company j in month m for fiscal year t. $CompanySize_{j,t,m-1}$ is defined as the natural log of the company's market capitalization at the end of the previous month.

Analysts tend to forecast more accurately when they have more experience and resources (Clement 1999; Lim 2001). We measured company-specific experience as the number of years analyst i has been following company j ($YearStk_{j,t,m}$). We measured general experience as the number of years since analyst i first appeared in the I/B/E/S database ($YearIBES_{j,t,m}$). $BrokerSize_{j,t,m}$ is the number of analysts who work for the same employer during the same forecast year as the analyst who makes the forecast. Analysts who work for larger firms tend to have more resources at their disposal.

Clement (1999) found that analysts' forecasts are less accurate the more stocks and the more industries they follow. $NumStk_{j,t,m}$ is the number of stocks for which analyst i supplies at least one forecast within the calendar year. $NumInd_{j,t,m}$ is the number of two-digit SIC industries for which analyst i supplies at least one forecast within the calendar year.

Previous studies have found that forecasting is more difficult when companies report a loss or a decline in earnings (Brown 2001). The $EPSLoss_{j,t}$ indicator equals 1 when the corresponding actual earnings of company j are negative. The $EPSDecline_{j,t}$ indicator equals 1 when actual earnings in fiscal year t are lower than actual earnings in the previous year.

Matsumoto (2002) argued that companies in industries with a higher risk of shareholder lawsuits and/or greater reliance on implicit claims with stakeholders are more likely to avoid missing analyst forecasts. The $Litigation_j$ indicator equals 1 for companies in high-litigation-risk industries: SIC codes 2833–2836 (biotechnology), 3570–3577 and 7370–7374 (computers), 3600–3674 (electronics), and 5200–5961 (retailing).

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Matsumoto (2002) also argued that labor-intensive companies try to avoid missing analyst forecasts because their stakeholders are concerned about company credit risk. Labor intensity, $Labor_{j,t,m-1}$, is defined as 1 minus the ratio of gross plant, property, and equipment (PPE) to total gross assets, where gross PPE is the quarterly Compustat item 118 and total gross assets is item 44 plus item 41. $Labor_{j,t,m-1}$ is measured at the end of the last quarter preceding forecast month m.

Richardson, Teoh, and Wysocki (2004) found lower forecast bias for companies with high growth opportunities. We used the market-to-book ratio ($MB_{j,t,m-1}$) at the end of the last quarter preceding the forecast month as a proxy for growth opportunities. The ratio is calculated as the market value of equity divided by the book value of common equity (Compustat quarterly data item 14 multiplied by item 61 and divided by item 59).

We used both the real GDP growth rate and the unexpected change in the real GDP growth rate to capture analysts' inability to forecast earnings accurately if the state of the economy changes substantially. $ActualGDP_t$ is the actual real GDP growth rate in fiscal year t. $UnexpectedGDP_{t,m}$ is defined as the difference between the expected real GDP growth rate and the actual real GDP growth rate in fiscal year t. For earnings forecasts made more than nine months before the fiscal year-end date, the expected real GDP growth rate in fiscal year t is defined as the real GDP growth rate in the quarter for which analysts made earnings forecasts. For forecasts made in Q2 (seven to nine months before the fiscal year-end date), we calculated the expected real GDP growth rate as (Growth in Q1 + 3 × Growth in Q2)/4. For forecasts made in Q3 (four to six months before the fiscal year-end date), we calculated the expected real GDP growth rate as (Growth in Q1 + Growth in Q2 + 2 × Growth in Q3)/4. For forecasts made within the three months before the fiscal year-end date, $UnexpectedGDP_{t,m}$ is set to zero.

Prior research and our results in Table 2 show that forecasts made earlier in the fiscal year are less accurate (Richardson, Teoh, and Wysocki 2004). To control for forecast horizon, we used $Month_m$, defined as the number of months until the fiscal year-end date. For example, for an analyst forecast made in October 1999 for the fiscal year ended December 1999, $Month_m$ equals 2. Richardson, Teoh, and Wysocki (2004) found that forecast bias has been declining gradually since the early 1990s. To address the concern that our results may be driven by this trend, we included a calendar year variable, $Year_t$, in the regression model (Equation 4). To control for unobserved company effects, we estimated the regressions with fixed company effects ($DCompany_j$).

The first set of estimation results in **Table 3** is for the regression model (Equation 4). The results imply that forecast bias declined by 0.24 percent of the stock price after the introduction of Reg FD. This finding confirms our earlier conjecture that the increase in forecast bias following Reg FD (observed in our univariate results) was driven by unexpectedly poor macroeconomic conditions. The decline in forecast bias following Reg FD is consistent with Lim's prediction (2001) that analysts become less optimistic when they rely less on insider information.

After the Global Settlement, the forecast bias is lower by 0.96 percent of the stock price compared with the forecast bias before Reg FD. This result is consistent with our univariate findings and implies that the Global Settlement and related regulations successfully neutralized analysts' conflicts of interest. The positive coefficient on *Month* suggests the presence of the walk-down trend. Forecast bias is high for earlier forecasts and becomes lower over time. On average, forecast bias increases by 0.14 percent of the stock price per month with the length of the forecast horizon.

Because the Global Settlement is an enforcement agreement between U.S. regulators and the Big-12 banks, we next examined whether the impact of the Global Settlement is limited to the Big-12 banks or whether there are spillover effects on other analysts.[16] In a recent study, Barber, Lehavy, McNichols, and Trueman (2006) reported that the proportion of buy recommendations declined significantly among all analysts after the implementation of NASD Rule 2711. They also documented that the decline was stronger for the sanctioned banks. Whether the Global Settlement has had a differential impact on analyst forecast bias, however, remains an open question.

To identify the differential impacts of Reg FD and the Global Settlement on Big-12 analysts, we compared the bias in the forecasts of Big-12 analysts with the bias in the forecasts of other analysts. In a univariate comparison, we found that, on average, the forecasts of analysts working for the Big-12 banks are statistically significantly less biased than the forecasts of their counterparts in each of the three periods. The differences, however, are economically trivial. For example, the difference between the mean forecast bias of Big-12 analysts and that of other analysts is –0.04 percent of the share price in the pre–Reg FD period, –0.09 percent after Reg FD, and –0.05 percent after the Global Settlement.

Table 3. The Impact of Reg FD and the Global Settlement on Forecast Bias

	(1)		(2)	
	Coefficient	*t*-Statistic	Coefficient	*t*-Statistic
RegFD	–0.24**	–3.29	–0.16*	–2.05
Glob	–0.96**	–10.68	–0.86**	–9.51
CompanySize	0.65**	16.89	0.67**	17.52
NumA	0.02**	3.39	0.01**	2.68
MB	–0.03**	–5.97	–0.03**	–5.59
YearStk	0.01	1.58	0.01**	2.59
YearIBES	0.00	1.54	0.00	0.78
NumStk	0.00*	–2.38	0.00*	–2.05
NumInd	–0.01	–1.18	–0.01	–1.40
BrokerSize	0.00	–1.64	0.00	–0.41
EPSLoss	5.40**	43.20	5.23**	40.53
EPSDecline	2.40**	62.82	2.38**	60.63
Litigation	–0.03	–0.24	–0.08	–0.66
Labor	0.52	2.12	0.47	1.89
ActualGDP	–0.04*	–2.05	–0.03	–1.23
UnexpectedGDP	–0.03**	–6.26	–0.04**	–6.61
Big12			–0.06**	–3.05
Big12 × RegFD			–0.07*	–2.04
Big12 × Glob			0.03	1.34
Month	0.14**	51.70	0.13**	47.76
Year	0.03*	2.16	0.02	1.09
Adjusted R^2	0.46		0.45	
No. of observations	434,268		434,268	
No. of companies	7,315		7,315	

Notes: This table presents the coefficients obtained from Equation 4. The dependent variable is earnings forecast bias, defined as the difference between the mean of all forecasts made in a particular month for a particular company and a particular fiscal year and the realized EPS, scaled by the stock price and multiplied by 100. The RegFD indicator equals 1 for forecasts made between 23 October 2000 and 20 December 2002. The Glob indicator equals 1 for forecasts made after 20 December 2002. Analyst coverage, NumA, is the number of outstanding forecasts used by I/B/E/S to calculate monthly consensus. CompanySize is the natural log of a company's market capitalization. Market-to-book ratio, MB, is the market value of equity divided by the book value of common equity. Company-specific experience, YearStk, is the number of years since the analyst made her first forecast for a particular stock. General experience, YearIBES, is the number of years since the first day the analyst appeared in I/B/E/S. NumStk and NumInd are the number of stocks and the number of industries covered by the analyst, respectively. The EPSLoss indicator equals 1 when the corresponding actual earnings of company *j* are negative. The EPSDecline indicator equals 1 when the realized earnings in fiscal year *t* are lower than the realized earnings in the previous year. BrokerSize is the number of analysts working for the employer of the analyst who makes the forecast. The litigation risk indicator, Litigation, equals 1 for companies in high-litigation-risk industries. Labor intensity, Labor, is (1 – Gross PPE/Total gross assets). The regressions are estimated with fixed company effects. The reported *t*-statistics reflect robust standard errors adjusted for heteroscedasticity and clustering by company.

*Significant at the 5 percent level.
**Significant at the 1 percent level.

To see whether the differential impacts of Reg FD and the Global Settlement on Big-12 and other analysts change when we control for company and analyst characteristics, as well as economic conditions, we re-estimated the regression model (Equation 4) with the Big-12 indicator and its interactions with the Reg FD and Global Settlement indicators included as additional independent variables.[17] The second set of results in Table 3 is for this regression. Consistent with our univariate results, the Big-12 indicator and its interaction with Reg FD are significant in statistical but not in economic terms. More importantly, the interaction of the Big-12 indicator with the Glob indicator is insignificant, both statistically and economically.

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These results imply that both Big-12 and other analyst forecasts were biased before Reg FD, which is consistent with Lin and McNichols (1998), who found no difference between the earnings forecasts of analysts affiliated with banks involved in underwriting deals with the covered companies and the forecasts of unaffiliated analysts. These results also imply that the impact of the Global Settlement and related regulations is the same among Big-12 and other analysts. This finding may reflect the fear of non-Big-12 firms that they may become targets of similar investigations. In addition, because Big-12 banks no longer reward optimism, the incentive for lower-tier analysts to make optimistic forecasts as a means of moving up to the bigger banks has also been reduced. Finally, the rules and regulations introduced by the SEC, NYSE, and NASD around the time of the Global Settlement covered all analysts.

We checked the robustness of our main conclusion—that forecast bias declined after both Reg FD and the Global Settlement—in a number of ways. First, we used an alternative definition of the forecast bias by normalizing it by the book value of equity per share.[18] Second, we changed the cutoff dates for each period by using the effective date of Rule 2711 instead of the announcement date of the Global Settlement. Third, to ensure that our conclusions were unaffected by changes in the sample composition across the three subperiods, we required at least one forecast by the same analyst for the same company in all three periods. Fourth, we dropped observations with stock prices under $5 to avoid any potential biases induced when the scaling factor is a small number. Fifth, we extended our sample period to include an earlier period (January 1984–December 1995). In all these cases, the results (not reported here) remain qualitatively the same as those reported in Table 3, confirming that forecast bias declined after Reg FD and especially after the Global Settlement.

We also examined the breadth of these effects by estimating forecast bias regressions (Equation 4) separately for 12 business sectors and for subsamples formed on the basis of annual quintile sorts by company size and analyst coverage.[19] The results (not reported here) show that the effects of the Global Settlement are negative for 11 of 12 sectors and are statistically significant for 9 sectors. The effects of Reg FD are negative for 8 of 12 sectors, but significantly so for only 6 sectors. Our results also show that the effect of Reg FD is concentrated among smaller companies and companies with low analyst coverage, whereas the effect of the Global Settlement is more widespread, with no clear cross-sectional pattern.

Conclusion

Analysts' conflicts of interest were evident before the Global Research Analyst Settlement and were not limited to the 12 banks covered by it. Reg FD made analysts less dependent on insider information and thus diminished analysts' motives to favor company managers by inflating their earnings forecasts. The impact of Reg FD is more significant for companies with a less transparent information environment in which insider information has the most value.

Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that of related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was announced. These results suggest that the recent efforts of regulators have helped neutralize analysts' conflicts of interest.

We thank Donal Byard, Terrence Martell, and seminar participants at Baruch College for helpful comments. Armen Hovakimian gratefully acknowledges the financial support of the PSC-CUNY Research Foundation of the City University of New York.

This article qualifies for 1 CE credit, inclusive of 1 SER credit.

Notes

1. Several rules and regulations were enacted around the Global Research Analyst Settlement—for example, NASD Rule 2711, NYSE Rule 472, and Regulation Analyst Certification. Because they were introduced over a relatively short period, determining the separate impact of each one of these regulatory actions is impossible. Nevertheless, all these rules and regulations share the same goal of reducing analysts' conflicts of interest. Therefore, we use the term Global Settlement to represent all the rules and regulations enacted around the Global Research Analyst Settlement to address analysts' conflicts of interest.
2. Scherbina (2004) found a negative relationship between the estimated bias that arises from self-selection in coverage and subsequent stock returns. Her results suggest that retail

investors fail to adjust for the bias. Malmendier and Shanthikumar (2007) found that retail investors react to stock recommendations literally. Institutional investors buy stocks that have "strong buy" ratings and sell stocks that have "buy" ratings, whereas retail investors buy in both cases. Kwag and Shrieves (2006) found that persistence in forecast errors can lead to potentially profitable trading strategies.

3. Overall, these studies found either no change (Bailey, Li, Mao, and Zhong 2003) or a decrease in forecast accuracy (Agrawal, Chadha, and Chen 2006; Mohanram and Sunder 2006) and forecast dispersion (Agrawal, Chadha, and Chen 2006) following Reg FD.
4. Kadan, Madureira, Wang, and Zach (2009) documented that stock recommendations have become less optimistic since the Global Settlement. Furthermore, they found that the likelihood of an optimistic recommendation is no longer associated with analyst affiliation. Ferreira and Smith (2006) found that investors have not changed the way they respond to analysts' changes in recommendations since Reg FD. Examining bid–ask spreads and trading activity following Reg FD, Lee, Rosenthal, and Gleason (2004) found no significant increase in volatility or in the adverse-selection component of bid–ask spreads.
5. Reg AC took effect on 14 April 2003. See the joint report by the NASD and NYSE (2005) for the effectiveness of the new rules.
6. The 10 investment banks are Bear Stearns, Citigroup, Credit Suisse First Boston, Goldman Sachs, J.P. Morgan, Lehman Brothers, Morgan Stanley, Merrill Lynch, UBS, and U.S. Bancorp Piper Jaffray. In 2008, Bear Stearns and Merrill Lynch were taken over because of their deteriorating financial positions, whereas Lehman Brothers ended up in bankruptcy. Because our sample period ends in 2006, these events did not affect our results.
7. These two investment banks are Deutsche Bank and Thomas Weisel Partners.
8. Because prior studies (e.g., Lin and McNichols 1998) found no cross-sectional differences in forecast bias between affiliated and unaffiliated analysts, one would not reasonably expect cross-sectional differences in the impact of the Global Settlement on these two analyst types.
9. Therefore, one would not reasonably expect cross-sectional differences in the impact of the Global Settlement on self-selection bias.
10. Forecasts for current-year EPS are the forecasts in I/B/E/S with code FPI 1. Forecasts for subsequent-year EPS are the forecasts in I/B/E/S with code FPI 2.
11. We excluded forecasts in the I/B/E/S Excluded Estimates file and forecasts for which actual earnings figures were missing.
12. The I/B/E/S Summary file contains monthly snapshots of consensus-level data and corresponding stock prices. The snapshots are as of the Thursday before the third Friday of every month. The reported stock prices in this file are the last available prices before the Thursday. I/B/E/S's earnings-related data and stock prices are split adjusted.
13. Using stock price to normalize forecast bias is common (see, e.g., Richardson, Teoh, and Wysocki 2004). Later in the article, we discuss the robustness of our findings to alternative scaling of analyst forecast errors.
14. We defined extreme values as those in 1 percent of both tails of the distribution. Variables that took only positive (negative) values were trimmed only on the right (left) tail of the distribution.
15. Realized earnings and forecasts are scaled by the stock price, consistent with the scaling of the bias measure.
16. Other regulations, such as NASD Rule 2711, affect all analysts.
17. In this analysis, for each forecast month of each sample company-year, the mean forecast bias is calculated separately for Big-12 and other analysts.
18. This step also ruled out the possibility that such events as the decimalization of stock prices in August 2000–April 2001 affected our findings.
19. The sector classification for each company is from the I/B/E/S Identifier file.

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Value Line®

In-Depth Guide

Reading a Value Line Research Report

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The In-Depth Guide to Reading a Value Line Research Report

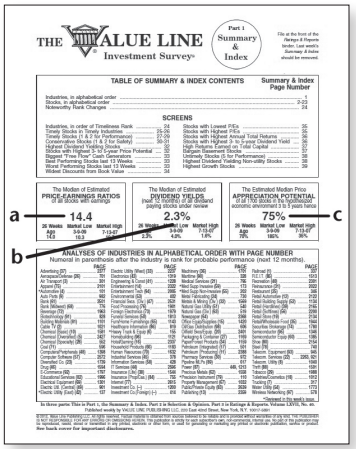
The Value Line Investment Survey® is a unique source of financial information designed to help investors make informed investment decisions that fit their individual goals and levels of risk. It is: (1) a proven forecaster of relative stock performance over the next six to 12 months; (2) a source of interpretative analysis on approximately 1,700 individual stocks and approximately 100 industries; and (3) a source of historical information to help investors spot trends.

I: GETTING STARTED

As a subscriber, you will receive three parts of *The Value Line Investment Survey* each week. Part 1 is the *Summary & Index*, Part 2 is *Selection & Opinion* and Part 3 is *Ratings & Reports*. Below we will describe each section and discuss some of the ways to use them.

Part 1—Summary & Index

Start with the *Summary & Index*. The front cover contains a Table of Contents, three important market statistics, and a list of all the industries we follow in alphabetical order with their current industry rank shown next to the name of the industry. The page number is to the right. The market statistics are found in three boxes. The first box (a) has the median of estimated price/earnings ratios of all stocks with earnings covered in *The Value Line Investment Survey* (approximately 1,700). The second box (b) shows the median of estimated dividend yields (total dividends expected to be paid in the next 12 months divided by the recent price) of all dividend-paying stocks in *The Value Line Investment Survey*. The third box (c) contains the estimated median price appreciation potential 3 to 5 years into the future for the approximately 1,700 stocks in The Value Line Investment Survey, based on *Value Line's* hypothesized economic environment 3 to 5 years hence. By studying these statistics, a fairly good picture emerges of how the universe of *Value Line* stocks—which comprises approximately 90% of the market capitalization of all stocks traded in U.S. markets and is therefore quite representative of the stock market as a whole — is currently being evaluated.



Summary & Index

Beginning on page 2, the *Summary & Index* also includes an alphabetical listing of all stocks in the publication with references to their location in Part 3, Ratings & Reports. If you are looking for a particular stock, look inside the *Summary & Index* section, which is updated each week to provide the most current data on all companies included in *The Value Line Investment Survey*.

To locate a report on an individual company, look for the page number just to the left of the company name. Then turn to that page in Part 3, *Ratings & Reports*, where the page number is shown in the right hand corner.

In the far left column of the Summary & Index is a number that refers to recent Supplementary Reports, if any, which are included on the back pages of *Ratings & Reports* If two stars (★★) appear in that column, it means that there is a Supplementary Report in the current Issue.

There are many columns in the **Summary & Index** with more information on each of the approximately 1,700 stocks we cover.

There is also a wealth of information in the stock screens toward the back of the ***Summary & Index,*** beginning on page 24.

These screens are a good place to start for anyone looking for investment ideas or help in forming a strategy. The screens are also useful for investors who want a list of stocks relevant to specific strategies they may have in mind.

Part 2—Selection & Opinion

Selection & Opinion (S&O) contains *Value Line's* latest economic and stock market commentary and investment ideas, along with one or more pages of research on interesting stocks or industries, and a variety of pertinent economic and stock market statistics. It also includes four model stock portfolios (Stocks with Above-Average Year-Ahead Price Potential, Stocks for Income and Potential Price Appreciation, Stocks with Long-Term Price- Growth Potential, and Stocks with Above-Average Dividend Yields). If you spend time with *Selection & Opinion* each week, you should be able to get some valuable investment ideas and a good understanding of *Value Line's* outlook for the economy.

THE VALUE LINE
Investment Survey®

PAGES 1397-1408
File in page order in the Selection & Opinion binder.

PART 2 — Selection & Opinion

Dear Subscribers,

As part of our ongoing efforts to keep The Value Line Investment Survey® the most valuable investment resource for our subscribers, all updated Ranks are now being released on the Value Line Web Site at 8:00 A.M. Eastern Time on Mondays. You can access the Web Site at any time at www.valueline.com, by entering your user name and password. We look forward to continuing to provide you with accurate and timely investment research. Thank you.

The Value Line View

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The Selection & Opinion Index appears in this issue on page 1402.

In Three Parts: Part 1 is the Summary & Index; Part 2 is Selection & Opinion; Part 3 is Ratings & Reports. Volume LXVII, No. 2

ECONOMIC AND STOCK MARKET COMMENTARY

The economic picture is getting a little brighter. To be sure, no alarm bells are going off. However, after months in which the metrics had generally pointed to faltering growth, data on new and existing home sales, industrial output and factory usage, retail sales, and the leading indicators are all suggesting that a mild pickup in activity is under way. These recent reports strengthen the case for our nation being able to bypass the ills now engulf ing the ailing euro zone.

That said, progress is likely to be slow and uneven until the latter stages of 2013. Although this ration, as noted, is unlikely to follow Europe down the troubled road to recession, the data may still be sluggish enough, and inventory caution still formidable enough, for growth to hold within the 1.5%-2.0% range until later in 2013. Then, presumably, payroll growth and housing should perk up further, lifting consumer and business confidence sufficiently to generate the spending needed to yield a broader-based and more substantial upturn in 2014.

Meanwhile, lingering issues are still about that could derail things in the interim. Mostly, these center on the euro zone (and its worsening economic ills) and the potential for a harder landing in China. Closer to home, there is the "fiscal cliff" of automatic tax hikes and spending cuts that are set to take effect by yearend unless the sitting Congress acts to postpone these disruptions until the new Congress can take its seat and, hopefully, address these issues.

Given such unknowns, the stock market's showing in 2012 has been uplifting. In fact, as the summer ends, the averages are within striking distance of multi-year highs. Better earnings, evolving optimism on the economy, modest valuations, and the compelling allure of increasing dividends are all making equities a popular investment choice currently.

Here, as well, there are some concerns. As with the economy, the threats from Europe, China, rising oil prices, and the "fiscal cliff" could bring on some short-term profit taking in a stock market that has done rather well in a comparatively short span of time. That said, . . .

Conclusion: We remain generally positive on the market's outlook for the coming six months. Please refer to the inside back cover of *Selection & Opinion* for our statistically-based Asset Allocation Model's current reading.

CLOSING STOCK MARKET AVERAGES AS OF PRESS TIME

	8/15/2012	8/22/2012	%Change 1 week	%Change 12 months
Dow Jones Industrial Average	13944.78	13972.76	+0.1%	+15.4%
Standard & Poor's 500	1403.53	1413.49	+0.6%	+23.8%
N.Y. Stock Exchange Composite	8179.93	8074.12	+0.6%	+15.7%
NASDAQ Composite	3130.93	3073.67	+1.4%	+31.7%
Value Line (Geom.)	3.42.00	3.41.78	+0.6%	+16.7%
American Stock Exchange Index	2420.90	2431.78	+0.4%	+8.7%
Value Line (Geometric)	389.72	392.94	+0.9%	+16.3%
Value Line (Arithmetic)	511.13	514.04	+0.6%	+19.2%
London FT-SE 100	5813.06	5778.20	+1.0%	+13.1%
Tokyo (Nikkei)	8525.04	9110.74	+2.3%	+5.8%
Russell 2000	804.26	812.56	+1.0%	+24.8%

Selection & Opinion

Part 3—Ratings & Reports

Ratings & Reports is the core of *The Value Line Investment Survey* with one-page reports on approximately 1,700 companies and one-page reports on approximately 100 industries. The company reports contain *Timeliness™*, *Safety™* and *Technical* ranks, our 3- to 5-year forecasts for stock prices, income and balance sheet data, as much as 17 years of historical data, and our analysts' commentaries. They also contain stock price charts; quarterly sales, earnings, and dividend information; and a variety of other very useful data. Each page in this section is updated every 13 weeks. When important, and often unforeseen, news occurs during these 13 week intervals, a Supplementary Report (appearing in the back section of *Ratings & Reports*) is published. If there is a Supplementary Report, its location will be shown in the far left hand column of the *Summary & Index*, near the company name. (Two stars—★★—indicate that the Supplementary Report is in the current week's Issue.)

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Part 3 Ratings & Reports

ISSUE 1
Pages 100-250

Ratings & Reports

Every week subscribers receive a new Issue of *Ratings & Reports* containing approximately 130 company reports grouped by industry and a smaller number of industry reports. The industry reports precede the reports on the companies in that same industry. Over the course of three months, revised reports are issued on all approximately 1,700 companies and nearly 100 industries.

II: PLANNING AN INVESTMENT STRATEGY

When planning an investment strategy, it is important to consider a large number of factors, including such things as your age, current financial situation, and risk tolerance. Of course, there are many other factors to think about, but the point is that you should not simply sit down and start picking securities.

We have created a guide called "Planning an Investment Strategy" that you may wish to read before taking any portfolio action. As a quick summary, you should diversify your portfolio across both asset classes (i.e., stocks, bonds, and foreign securities) and within asset classes (i.e., owning a variety of stocks and bonds).

In addition, you do not have to handle every portion of your portfolio. Instead, you might hire someone else to handle the components that you do not have the desire or experience to oversee. An example of this would be to buy a diversified fixed-income mutual fund for the bond portion of your portfolio, while maintaining a collection of stocks yourself. The right mix of "outsourcing" and personal direction is an individual decision, but in the end you should create a portfolio that is hopefully both profitable and enjoyable to manage.

Again, we encourage you to take the time to read through the "Planning an Investment Strategy" guide so that you can start your portfolio on a solid foundation.

III: CREATING A LIST OF STOCKS FOR FURTHER RESEARCH

Once you have decided on a foundation portfolio, most likely consisting of a collection of asset-class baskets, you will need to find securities to fill those baskets. There are many ways to use *The Value Line Investment Survey* to find the equities that are most appropriate for your needs.

There are approximately 1,700 stocks in our coverage universe, so opening the first issue and starting to examine each stock report in search of the few you want to own would be a time consuming and, frankly, nearly impossible task. To assist our readers in creating "short lists" of stocks for further consideration, we included a number of stock screens in the back of each *Summary & Index*.

The screens are updated weekly and cover a broad range of investment options, including Timely Stocks in Timely Industries, Conservative Stocks, Highest Yielding Stocks, and Stocks with Highest 3- to 5-Year Appreciation Potential. A description of the screens is provided if the title of a screen is not self-explanatory. There are, of course, many more screens than the ones listed here, so you should take a look at the pages in the back of the Summary & Index to get a feel for which ones will best fit your specific needs. Regardless of which screens you choose to use, this approach will provide you with a short list of companies to research.

For those who want more advice than a static screen, we have also created four model portfolios: Portfolio I (Stocks with Above-Average Year-Ahead Price Potential), Portfolio II (Stocks for Income and Potential Price Appreciation), Portfolio III (Stocks with Long-Term Price Growth Potential), and Portfolio IV (Stocks with Above-Average Dividend Yields). These portfolios are overseen by senior Value Line analysts and are updated weekly in the *Selection & Opinion section*. Periodically, a more in-depth review is provided detailing the most recent performance of each portfolio. These portfolios offer another convenient starting point for selecting stocks for inclusion in your own portfolio.

On an ongoing basis, we also provide stock screens and Stock Highlights in the *Selection & Opinion* section. The screens go beyond those included on a weekly basis in the *Summary & Index* and often provide a different and unique view of an investment approach. The Stock Highlights are a more in-depth review of a company that we believe merits a second look. Although these two options may not be the best starting point for you, they can play an important role in providing new and interesting investment ideas down the road.

IV: RESEARCHING A STOCK USING THE VALUE LINE PAGE

A sample Value Line report is included at the back of this guide. The numbers below reference back to the sample page.

To start studying a stock, we suggest that you concentrate on various features found on every company page of *Ratings & Reports*. Begin by using the *Timeliness*,™ *Safety*™ and Technical ranks that appear in the upper left corner of each page (1). Next, look at the analyst's commentary in the bottom half of each report (17). Then look at our various forecasts for financial data. Estimated financial data is shown on the right side (bold italic print) of the Statistical Array (15). Growth rates are in the *Annual Rates* box (23). A stock's *Target Price Range* is on the right-hand side of the graph (11), and 3- to 5-year stock price *Projections* are in the projections box (29). Finally, go to the historical financial data appearing in the left side of the Statistical Array (26). Illustrations and more detail follow.

Value Line Ranks

(see (1) on the sample page)

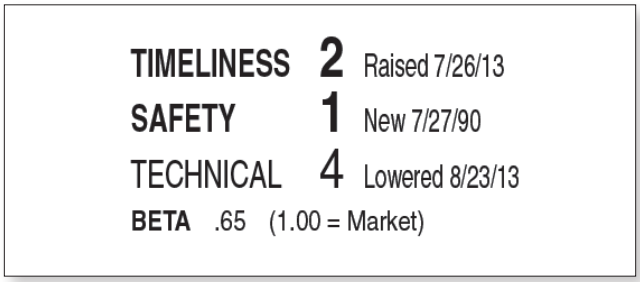
Timeliness

The *Timeliness* rank is *Value Line's* measure of the expected price performance of a stock for the coming six to 12 months relative to our approximately 1,700 stock universe. Stocks ranked 1 (*Highest*) and 2 (*Above Average*) are likely to perform best relative to the approximately 1,700 stocks we follow. Stocks ranked 3 are likely to be average performers. Stocks ranked 4 (*Below Average*) and 5 (*Lowest*) are likely to underperform stocks ranked 1 through 3 in *Value Line's* universe.

At any one time, there are 100 stocks ranked 1; 300 ranked 2; approximately 900 ranked 3; 300 ranked 4; and 100 ranked 5.

The most important factor in determining the *Timeliness* rank is earnings growth. Companies whose earnings growth over the past 10 years has been greater than their stocks' price appreciation tend to have favorable ranks. In addition, the ranks take into account a stock's recent price performance relative to all approximately 1,700 stocks in the *Value Line* universe. A company's recent quarterly earnings performance and any recent earnings surprises caused because a company reported results that were significantly better or worse than expected are also factors. These are all combined to determine the *Timeliness* rank.

Just one word of caution. Stocks ranked 1 for *Timeliness* are often more volatile than the overall market and tend to have smaller capitalizations (the total value of a company's outstanding shares, calculated by multiplying the number of shares outstanding by the stock's price per share). Conservative investors may want to select stocks that also have high *Safety* ranks because they are more stable issues.



Sample Ranks Box

Company's Financial Strength	A++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	100

Financial/Stock Price Data

Safety

The *Safety* rank is a measure of the total risk of one stock compared to all others in our approximately 1,700 stock universe. As with *Timeliness* rank, *Value Line* ranks each stock from 1 (Highest) to 5 (Lowest). However, unlike *Timeliness* rank, the number of stocks in each category from 1 to 5 may vary. The *Safety* rank is derived from two measurements (weighted equally) found in the lower right hand corner of each page 29: a Company's Financial Strength and a Stock's Price Stability. Financial Strength is a measure of a company's financial condition, and is reported on a scale of A++ (highest) to C (lowest). The largest companies with the strongest balance sheets get the highest scores. Price Stability is based on a ranking of the standard deviation (a measure of volatility) of weekly percent changes in the price of a company's own stock over the last five years, and is reported on a scale of 100 (highest) to 5 (lowest) in increments of 5. Generally speaking, stocks with *Safety* ranks of 1 and 2 are most suitable for conservative investors.

A stock's Price Growth Persistence and a company's Earnings Predictability are also included in the box above, but do not factor into the *Safety* rank. However, they are useful statistics. Price Growth Persistence is a measure of the consistency of relative stock price growth over the past 10 years. Earnings Predictability is a measure of the reliability of an earnings forecast.

Technical

The *Technical* rank is primarily a predictor of a stock's short term (three to six months) relative price change. It is based on a proprietary model which examines 10 relative price trends for a particular stock over different periods in the past year. It also takes into account the price volatility of each stock. The *Technical* ranks also range from 1 (Highest) to 5 (Lowest). At any one time, about 100 stocks are ranked 1; 300 ranked 2; 900 ranked 3; 300 ranked 4; and 100 ranked 5.

Beta

Beta is a measure of the volatility of a stock relative to the overall stock market and is calculated by *Value Line*. A *Beta* of 1.0 suggests that a stock will move up and down in roughly lock-step with the market, so that a 3% increase or fall in the broader market would likely be accompanied by a similar percentage move in the stock. A *Beta* higher than 1.0 means a stock tends to move more than the market, while a *Beta* lower than 1.0 suggest that the stock in question will move in a muted relationship to a move in the market.

Industry Timeliness

Value Line also publishes *Industry* ranks which show the *Timeliness* of each industry. The *Industry* ranks indicate how *Value Line* believes the prices of stocks within 90 or more industries will perform relative to each other. **These ranks are updated weekly and published on the front cover and on page 24 of the *Summary & Index*. They also appear at the top of each Industry Report in *Ratings & Reports*.** The *Industry* rank is calculated by averaging the *Timeliness* ranks of each of the stocks assigned a *Timeliness* rank in a particular industry.

Analyst's Commentary

(see 17 on the sample page)

Next, look at the analyst's written commentary in the lower half of the page. Many readers think this is the most important section of the page. In the commentary, the analyst discusses his/her expectations for the future.

Timely shares of Johnson & Johnson continue to move higher. Investors have been favoring this issue of late, likely thanks to its stability, predictability, and earnings growth prospects. The recent second-quarter sales and earnings beats added some fuel to fire, too. All told, JNJ stock is up more than 30% since the start of the 2013, and the uphill climb has been surprisingly steady. We continue to recommend this blue chip to momentum chasers. **The company's second-quarter performance was much better than expected.** Sales were $17.9 billion, up 9% from a year earlier, as operational growth of 10% was slightly offset by a 1% drag related to currency translation. The top-line figure was on a par with our estimate, but was roughly $175 million ahead of the consensus. J&J also shined on the bottom line, as adjusted share earnings climbed 14%, to $1.48. (GAAP share net nearly tripled, to $1.30.) Both *Value Line* and Wall Street analysts, on average, were looking for adjusted share profits of $1.39. All of J&J's divisions contributed to the positive June-quarter performance, including the embattled Consumer segment. The Pharmaceuticals and Medical Devices & Diagnostics groups both shined, posting double-digit revenue growth in the period. **We have bolstered our 2013 share-earnings target.** Management was hesitant to raise guidance by a considerable margin, even after putting together back-to-back strong performances in the March and June quarters. In fact, the company only increased 2013 share-earnings guidance from $5.35-$5.45 to $5.40-$5.47. We were already expecting share net to come in at $5.43, while most on Wall Street were looking for $5.41. As a result, we have added $0.03 to our full-year target, but we actually cut $0.06 from our second-half estimates. Our top-line call has been slightly reduced, to $71.4 billion. **This top-quality blue chip is a good option for both momentum-oriented and conservative investors, but those with a longer-term horizon should probably look elsewhere, for now.** The recent increase in share price has really discounted this issue's 3- to 5-year appeal. The dividend yield is good, however, and JNJ is as stable as they come.

Erik A. Antonson *August 23, 2013*

Sample Analyst's Commentary
(Also see item 17 on the sample page)

There are times when the raw numbers don't tell the full story. The analyst uses the commentary to explain why the forecast is what it is. The commentary is also particularly useful when a change in trend is occurring or about to occur. As an example, a stock may have a poor *Timeliness* rank but the analyst thinks earnings could turn around in the future. In this case, the analyst may use the commentary to explain why he/she thinks conditions are likely to get better, thus giving the subscriber insight into what is happening and why.

Value Line's Financial Data

(see 15 and 26 on the sample page)

In the Statistical Array in the center of the report (where most of the numbers are), Value Line provides both historical data and financial projections.

Financial Estimates

(see 15 and 22 on the sample page)

The estimates of sales, earnings, net profit margins, income tax rates, and so forth are all derived from spreadsheets maintained on every company and printed in ***bold italics***. The numbers are based on an analyst's latest thinking about where a company may be in the future. Our analysts regularly review their projections and discuss them with a company's management. Afterwards, they make whatever adjustments they believe are warranted.

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
8.41	8.80	9.88	10.47	10.83	12.23	14.10	15.94	16.98	18.43	21.51	23.02	22.47	22.49	23.87	24.19	*25.95*	*27.25*	Sales per sh A	*32.45*
1.62	1.83	2.03	2.27	2.46	2.85	3.36	3.94	4.25	4.60	5.23	5.70	5.69	5.92	6.25	6.48	*7.20*	*7.60*	"Cash Flow" per sh	*9.05*
1.21	1.34	1.49	1.70	1.91	2.23	2.70	3.10	3.50	3.76	4.15	4.57	4.63	4.76	5.00	5.10	*5.46*	*5.80*	Earnings per sh B	*7.30*
.43	.49	.55	.62	.70	.80	.92	1.10	1.28	1.46	1.62	1.80	1.93	2.11	2.25	2.40	*2.59*	*2.79*	Div'ds Decl'd per sh C■	*3.45*
.52	.54	.62	.59	.57	.71	.76	.73	.88	.92	1.04	1.11	.86	.87	1.06	1.06	*1.10*	*1.10*	Cap'l Spending per sh	*1.15*
4.59	5.06	5.83	6.76	7.95	7.65	9.05	10.71	12.73	13.59	15.25	15.35	18.37	20.66	20.05	23.33	*25.75*	*28.40*	Book Value per sh D	*37.50*
2690.3	2688.1	2779.4	2781.9	3047.2	2968.3	2966.0	2971.0	2974.5	2893.2	2840.2	2769.2	2754.3	2738.1	2724.4	2716.5	*2750.0*	*2730.0*	Common Shs Outst'g E	*2680.0*
24.9	28.1	31.6	26.4	27.2	25.9	19.4	18.1	18.5	16.6	15.4	14.3	12.5	13.1	12.7	13.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.5*
1.44	1.46	1.80	1.72	1.39	1.41	1.11	.96	.99	.90	.82	.86	.83	.83	.80	.84			Relative P/E Ratio	*.90*
1.6%	1.3%	1.2%	1.4%	1.3%	1.4%	1.8%	2.0%	2.0%	2.3%	2.5%	2.8%	3.3%	3.4%	3.5%	3.6%			Avg Ann'l Div'd Yield	*3.5%*
CAPITAL STRUCTURE as of 9/30/13						41862	47348	50514	53324	61095	63747	61897	61587	65030	67224	*71400*	*74400*	Sales ($mill) A	*87000*
Total Debt $14,982 mill. **Due in 5 Yrs** *$7,400 mill.*						31.3%	31.6%	30.6%	28.7%	29.4%	29.5%	31.6%	31.4%	32.3%	35.7%	*35.8%*	*35.8%*	Operating Margin	*36.0%*
LT Debt $9,643 mill. **LT Interest** *$420 mill.* (12% of Capital)						1669.0	2124.0	2093.0	2177.0	2777.0	2832.0	2774.0	2939.0	3158.0	3666.0	*4200*	*4400*	Depreciation ($mill)	*4760*
						8096.6	9298.0	10545	11133	12085	12949	12906	13279	13867	14345	*15600*	*16400*	Net Profit ($mill)	*19600*
Leases, Uncapitalized Annual rentals $251 mill.						30.2%	27.6%	24.8%	23.3%	22.1%	23.5%	22.0%	21.1%	20.1%	23.1%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
						19.3%	19.6%	20.9%	20.9%	19.8%	20.3%	20.9%	21.6%	21.3%	21.3%	*21.8%*	*22.0%*	Net Profit Margin	*22.5%*
Pension Assets-12/12 $17.5 bill. **Oblig.** $21.8 bill.						9547.0	13093	16759	3914.0	10108	13525	17610	24235	31505	21854	*24400*	*26900*	Working Cap'l ($mill)	*35200*
						2955.0	2566.0	2017.0	2014.0	7074.0	8122.0	8223.0	9156.0	12969	11489	*11800*	*12100*	Long-Term Debt ($mill)	*13300*
Preferred Stock None						26869	31813	37671	39516	43519	42511	50586	56579	57080	64826	*70800*	*77500*	Shr. Equity ($mill)	*105500*
Common Stock 2,818,073,863 shares						27.4%	27.3%	26.5%	27.1%	24.1%	26.0%	22.3%	20.6%	20.2%	19.1%	*19.0%*	*18.5%*	Return on Total Cap'l	*17.5%*
as of 7/26/13						30.1%	29.2%	27.8%	28.3%	27.9%	30.5%	25.5%	23.5%	24.3%	22.1%	*22.0%*	*21.0%*	Return on Shr. Equity	*19.5%*
MARKET CAP: $259 billion (Large Cap)						19.9%	19.0%	17.8%	17.5%	17.1%	18.6%	15.0%	13.2%	13.5%	11.9%	*11.5%*	*11.5%*	Retained to Com Eq	*10.5%*
						34%	35%	36%	38%	39%	39%	41%	44%	44%	46%	*47%*	*47%*	All Div'ds to Net Prof	*47%*

Sample Statistical Array

Historical Financial Data

(see 26 on the sample page)

Many investors like to use the Statistical Array to do their own analysis. They, in particular, use the historical data in the center of each report to see how a company has been

doing over a long time frame. It's worth pointing out that while all of the data are important, different readers find different data items to be most useful.

The numbers are probably most helpful in identifying trends. For example, look at sales per share to see if they have been rising for an extended period of time. Look at operating margins and net profit margins to see if they have been expanding, narrowing or staying flat. Also check the percentages near the bottom to see if the Return on Total Capital or the Return on Shareholders' Equity have been rising, falling or remaining about the same.

Annual Rates Of Change

(see 23 on the sample page)

At this point, it may be helpful to look at the Annual Rates box in the left-hand column. This box shows the compound annual growth percentages for sales, cash flow, and other items for the past 5 and 10 years and also *Value Line's* projections of growth for each item for the coming 3 to 5 years. Trends are also important here. Check whether growth has been increasing or slowing and to see if *Value Line's* analyst thinks it will pick up or fall off in the future. (Specific estimates for various data items for three to five years in the future can be found in bold italicized type in the far right hand column of the Statistical Array.)

Target Price Range and 3- to 5-year Projections

(see 11 and 29 on the sample page)

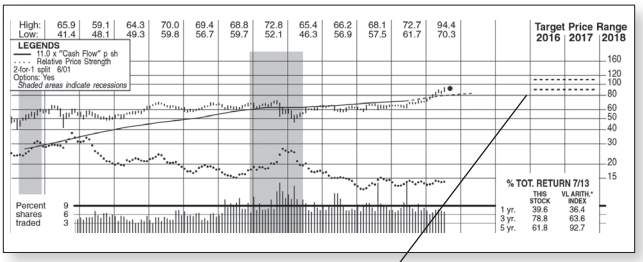
In the upper right-hand section of each report is a Target Price Range for each stock. This is the range in which the price is likely to fall during the period 3 to 5 years hence. The range is based on the analyst's projections in the period 3-5 years out for earnings per share multiplied by the estimated price/earnings ratio in the Statistical Array for the same period. The width of the high-low range depends on the stock's *Safety* rank. A stock with a high *Safety* rank has a narrower range, one with a low rank, a wider one.

In the left hand column of each report, there is also a box which contains 3- to 5-year Projections for a stock price. There you can see the potential high and low average prices we forecast, the % price changes we project, and the expected compound annual total returns (price appreciation plus dividends). To make these calculations, analysts compare the expected prices out 3 to 5 years into the future (as shown in the Target Price Range and Projections box) with the recent price shown at the top of the report.

Investors whose primary goal is long-term price appreciation should study the 3- to 5-year projections carefully and choose stocks with above-average appreciation potential. For comparative purposes, you can find the Estimated Median Price Appreciation Potential for all approximately 1,700 stocks on the front page of the *Summary & Index*.

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '10-'12 to '16-'18
Sales	7.5%	4.5%	*5.5%*
"Cash Flow"	9.5%	6.0%	*6.5%*
Earnings	10.0%	5.5%	*6.5%*
Dividends	12.5%	9.0%	*7.5%*
Book Value	11.5%	9.5%	*9.5%*

Sample Annual Rates Box



Target Price Range (3 to 5 years)

V: EXAMINING A VALUE LINE PAGE IN MORE DETAIL

In the following section, we are going to examine an actual *Value Line* page, with the objectives of interpreting the array of statistical data presented and weighing the data and the accompanying comment against your needs. We have chosen for examination a report on Johnson & Johnson, a large and well-known manufacturer of health care products.

Putting Data in Perspective

Looking at the top of the page, we can see that Johnson & Johnson's stock price in August 2013 was $92.00 a share (item 5 on the sample page). By itself, the stock price means very little. In the line below the price, annual high and low prices for each year from 2002 through mid-2013 are indicated. Below the high and low annual prices is a price chart (graph) that shows monthly price ranges for essentially the same period, along with other useful information that we will discuss below. We note here, though, that while Johnson & Johnson stock has traded in a relatively narrow range, with the exception of late 2009 to mid-2010, it has still climbed about 120% from its low of 41.40 in 2002 (adjusted for a stock split in 2001).

At the current quotation, is the stock undervalued or overvalued? The fact that the "cash flow" line is above the price of the stock indicates that it appears to be undervalued. Also, sales per share, cash flow per share, earnings per share, and book value per share are all near historical highs, as can be seen in the Statistical Array (items 15 and 26 on the sample page).

Price Earnings Ratio—This is probably the most widely used measure of stock valuation. *Value Line* shows a variety of P/E ratios on every company page, as discussed below:

The **P/E ratio** on the very top of the *Value Line* page (item 6 on the sample page). This is calculated by dividing the recent price of the stock by the total of the last six months of earnings and the next six months of estimated earnings.

The **Relative P/E ratio** (item 8). This compares the P/E of one stock with the median of estimated P/E ratios of all stocks under *Value Line* review. A relative P/E of more than 1 indicates that a stock's P/E ratio is currently higher than that of the *Value Line* universe; a P/E of less than 1 indicates that this stock's P/E is less than the *Value Line* average.

The Trailing P/E ratio (item 7). This is calculated by dividing the recent price of the stock by the past 12 months of actual (reported) earnings. This is the figure shown in most newspapers and on financial web sites.

The Median P/E ratio (item 7). This is the average annual P/E ratio of a stock over the past 10 years, with certain statistical adjustments made for unusually low or high ratios.

The Average Annual P/E ratio (items 15 and 26). This figure is calculated by dividing the average price for each year by the actual reported earnings for the same year and is shown in the Statistical Array.

The Relative (Annual) P/E ratio (items 15 and 26). This figure is calculated by dividing the *Average Annual* P/E of a stock with the *Average Annual* P/E of all stocks under *Value Line* review in the same year.

To gauge the significance of the recent price of a stock, the reader must look at the price in relation to a variety of data. As far as P/Es are concerned, the current P/E ratio and relative P/E ratio for Johnson & Johnson's stock, are below those of most stocks in the *Value Line* universe. In addition, we expect Johnson & Johnson to continue to trade at a valuation that is below the market average.

Low P/E ratios may mean that the stock is underpriced, unless there are factors indicating that there will be a significant decline in the company's fundamentals. Is this the case with Johnson & Johnson? Probably not, since management has been very vigilant in its efforts to maximize returns from its businesses, and the *Value Line* analyst is expecting continued profit growth over the three to five years subsequent to 2013. Johnson & Johnson's relative P/E ratio of 0.95 (item 8), a lower valuation than found in the average stock followed by *Value Line*, likely reflects the fact that the company's upward earnings trend over the past 15 years has recently moderated.

The Dividend Yield (item 10 in the right top corner of the sample page) shows the expected return from cash dividends on the stock over the next 12 months, as a percentage of the recent price. Johnson & Johnson's yield of 3.5% is above the median of all dividend-paying stocks in

the *Value Line* Universe. (The median is shown each week on the cover of the *Summary & Index* section.) We also see that the company has increased the dividend in every year since 1997, as shown in line four of the Statistical Array in the center of our report, and *Value Line's* analyst thinks additional increases are forthcoming. Many investors view regular increases in a dividend very positively.

The Price Chart

Next, look at Johnson & Johnson's price chart (or graph) at the top of the report. The first thing to look at is the price history, shown by the small vertical bars in the center of the graph. Those bars show the high and low monthly prices for the stock (adjusted for any subsequent stock splits or dividends). Looking at the bars, you can see that, for the most part, the stock price has marched in place from 2002 through 2012.

Now look at the "cash flow" line, the solid line running from 2001 through the middle of 2012, which is more fully described below. The dashed line from mid-2012 to mid-2014, which is an extension of the "cash flow" line, is *Value Line's* projection of the line for those years. For most of the past 12 years, Johnson & Johnson's stock has traded above the "cash flow" line. In the past four years or so, however, the stock has traded below the line.

Finally, look at the **Relative Price Strength** line, the faint small dotted line, usually toward the bottom of the chart. This shows the relative performance of Johnson & Johnson stock versus the entire universe of *Value Line* stocks; when the **Relative Price Strength** line is rising, it means a stock is acting better than the universe. When it is falling, a stock is doing worse than the *Value Line* universe.

At the very bottom of the chart, we show volume of trading each month (item 14) as a percent of total shares outstanding. The *Legends* box (item 2) in the upper left of the price chart contains, among other things, information on the "cash flow" multiple, a record of stock splits, and whether or not there are options traded.

The **Target Price Range** (item 11) in the upper right corner of the price chart indicates where *Value Line's* analyst believes the stock is most likely to be selling in the 3- to 5-year period. This box should be viewed in conjunction with the *Projections* box (item 29) near the top left-hand corner of the page, which also gives our 3- to 5-year projections. For Johnson & Johnson, we expect the average price to hover between 90 and 105, which would be between 40% and 65% above the current level.

Just above the *Projections* box is a section containing the *Value Line Timeliness, Safety,* and *Technical* ranks, plus a Beta calculation. Johnson & Johnson's Beta of .65 reveals that this stock is likely to move up and down much more slowly than the typical stock on the New York Stock Exchange. If you are looking for stability, a stock like Johnson & Johnson, with a low Beta, is a good option.

The "Cash Flow" Line

The price chart at the top of the Johnson & Johnson page contains, among other things, a monthly price history for the stock (the vertical bars) overlaid by a solid line that we call the "cash flow" line (sometimes also called the "*Value Line*"). To plot the line, we multiply cash flow per share (net income plus depreciation and amortization less preferred dividends divided by the number of shares outstanding at the end of the year) by a number (multiple) determined by our analyst. The goal is to create a "line" that most closely matches a company's stock price history and also "fits" the projected 3- to 5-year *Target Price Range*. In the case of Johnson & Johnson, the "cash flow" multiple is now 12.0. (The multiple can, and often does, change over time.)

The concept of a "cash flow" multiple is not too different from that for a Price/Earnings multiple (or ratio). The difference here is that instead of dividing the recent price of a stock by 12 months of earnings to create a P/E multiple, we divide the recent price by the total of 12 months of earnings plus 12 months of depreciation (and amortization, if there is any).

There is evidence that some stocks will generally trade at a price close to the "cash flow" line. In those cases when a stock is trading above the "cash flow" line, it will often move back down toward the "cash flow" line. When it is trading below, it will often do the opposite. In some cases, a stock may trade above or below the "cash flow" line for considerable periods of time.

Historical Results and Estimates

For each of the approximately 1,700 companies *Value Line* follows, we usually present per-share data going back up to 17 years in the Statistical Array in the center of each report. The historical data (item 26) appear on the left side and are presented in regular type. We also project statistical data (item 15) for the current fiscal year, next fiscal year, as well as three to five years into the future. ***These projections are presented in bold italics.***

Now look at a list of items in the Statistical Array (items 15 and 26).

Sales per share, in the top line, is an important series. When earnings per share are depressed because of poor net profit margins, a high level of sales per share can suggest the potential for an earnings recovery. It would be disconcerting, however, if sales per share declined in tandem with earnings per share.

"Cash flow" per share (second line), as commonly used by analysts, is the sum of reported earnings plus depreciation, less any preferred dividends, calculated on a per-share basis, also now includes stock option expense. It is an indicator of a company's internal cash-generating ability—the amount of cash it earns to expand or replace plant and equipment, to provide working capital, to pay dividends, or to repurchase stock. Johnson & Johnson's "cash flow" per share has expanded significantly since 1996.

Earnings per share (third line) are shown by *Value Line* as they were reported to stockholders, excluding nonrecurring items and adjusted for any subsequent stock splits or stock dividends. According to current accounting guidelines, companies now report earnings two ways. The first is basic earnings per share, which is the earnings available to common shareholders divided by the weighted average number of shares outstanding for the period. The second is diluted earnings per share, which reflects the potential dilution that could occur if securities or other contracts to issue common stock (like options and warrants) were exercised or converted into common stock. *Value Line* shows only one earnings figure in our statistical presentation; that figure is clearly identified in the footnotes (item 20), and it is almost always the diluted earnings figure.

For Johnson & Johnson, earnings per share have expanded consistently between 1997 and 2012. As indicated in footnote (B) (*item 20*) near the bottom edge of the report page, its earnings per share are now based on diluted shares outstanding.

Dividends Declared per share (fourth line) are usually the highest, in proportion to earnings, at older and larger companies, which tend to have slower-than-average growth. Directors of growth-oriented companies more often than not prefer to pay small or "token" dividends, or none at all, so they can reinvest earnings in the business. Johnson & Johnson has paid out between 39% and 46% of its earnings in dividends and invested the remainder in the business during the past five years and the percentage is likely to be about 47% over the next few years. A payout of 25%-30% is generally typical of larger capitalization companies followed by *Value Line*.

Capital Spending per share (fifth line) is the amount that a company spends on new plant and equipment. It doesn't include funds used for acquisitions of other companies.

Book Value per share (sixth line) is common shareholders' equity determined on a per-share basis. It includes both tangible assets, like plant and receivables and inventories, as well as intangibles, like the value of patents or brand names, known as "goodwill." Any significant intangibles will normally be indicated in a footnote. If all assets could be liquidated at the value stated on the company's books, all liabilities such as accounts payable, taxes, and long-term debt paid, and all preferred stockholders compensated, the book value is what would be left for the common stockholders.

The number of **Common Shares Outstanding** (seventh line) is also listed in the Statistical Array. Sometimes net income rises, but earnings per share do not, because the number of shares outstanding has increased. This may happen because a company is issuing stock to pay for acquisitions or to fund internal growth. As a result, sales and profits may soar, while per-share sales and earnings lag. On the other hand, when cash-rich companies buy their own shares, earnings per share can rise even if net income is stable.

The **Average Annual P/E Ratio** (eighth line) shows what multiple of earnings investors have been willing to pay for a stock in the past and the P/E ratio the analyst expects out 3 to 5 years. Johnson & Johnson's average annual P/E was at an unusually high levels between 1997 and 2002 when drug and medical stocks were in favor; it has narrowed considerably over the past ten years.

The **Relative P/E Ratio** (ninth line) shows how the stock's price-earnings ratio relates to those of all stocks in the *Value Line* universe. Johnson & Johnson's relative P/E of 0.95 in August 2013 was below that of the typical stock. The *Value Line* analyst thinks it will continue to be below average in the 2016-18 period.

The **Average Annual Dividend Yield** (10th line) is of special interest to conservative investors, many of whom are more concerned with income than with a stock's appreciation potential. Income-oriented investors should look for stocks with yields that are higher than the average shown each week in the center box of the front cover of the *Summary & Index*, but they should also look at the trend of dividends over time. Johnson & Johnson's dividend has been increased in each year shown on our page, and the analyst thinks it will continue to rise. Steady increases are very attractive for many investors. Investors should also look carefully at a company's Financial Strength to make certain that the company will be able to continue to pay the dividend. A good rule of thumb for conservative investors is to invest only in companies with Financial Strength ratings of at least B+.

Company Financial Data

The *Sales* figure (11th line) is the most common measure given when referring to a company's size. Johnson & Johnson's sales in 2012 were about 1.6 times the amount recorded in 2003, a very strong performance.

The **Operating Margin** (12th line) indicates what percentage of sales is being converted into operating income. (Operating income is total sales minus the cost of goods sold and selling, general and administrative expenses. It is also referred to as EBITDA, or earnings before interest, taxes, depreciation, and amortization.) At Johnson & Johnson, this figure peaked in 2012, and it appears poised to surpass those levels in the near future.

Depreciation (13th line) shows the amount charged against operating profits to reflect the aging of a company's plant and equipment. That number has risen quite steadily, but it declined in 2009 and it resumed the uptrend in 2010.

Net Profit (14th line) is the amount the company earned after all expenses including taxes, but excluding nonrecurring gains or losses and the results of discontinued operations. Usually, the higher the net, the higher the per-share earnings. Johnson & Johnson's net profit has grown considerably since 2003, and has risen in every year but in 2009, when it was little changed.

Johnson & Johnson's *Income Tax Rate* (15th line) averaged about 28% between 2003 and 2005, and *Value Line's* analyst thinks it will be about 22% in the foreseeable future. Income tax rates will normally remain steady unless the federal tax rate changes in the U.S. or unless a company increases or decreases the percentage of business it does overseas, where tax rates are different.

Net Profit Margin (16th line) shows net income after taxes as a percentage of sales (or revenues). Here, the trend is the most important thing, with rising margins usually being favorable. It is often worthwhile to compare the net margin with the operating margin. Usually the two series move together, though not always. Depreciation charges, interest expense, income taxes, and other costs are deducted from (and other income added to) operating income in the determination of net profit. Where there is a disparity in the trends of the net and operating margins, it may be worth taking a second look. (If depreciation, interest charges, or tax rates move sharply in any direction, there will be an impact on net profits, and it would be worthwhile to try to determine why the change occurred.)

Johnson & Johnson's *Net Profit Margin* reached a record level in 2010, and we expect that mark to be bested in the near future.

Working Capital (17th line), the company's current assets less current liabilities, indicate the liquid assets available for running the business on a day-to-day basis. The higher a company's sales, the more working capital it typically has and needs. But we caution that a number of large companies with steady revenue streams no longer believe large amounts of working capital are necessary. In those cases, a negative working capital may be perfectly

acceptable because a company can meet normal operating expenses from consistent cash receipts.

Long-term Debt (18th line) is the total debt due more than one year in the future. In the case of Johnson & Johnson, the amount is quite low relative to shareholders' equity.

Shareholders' Equity (19th line), also known as net worth, is the total stockholders' interest (preferred and common) in the company after all liabilities have been deducted from the company's total assets. All intangible assets such as goodwill, patents, and, sometimes, deferred charges are included in shareholders' equity. Johnson & Johnson's equity has grown appreciably over the years, primarily from retained earnings.

Return on Total Capital (20th line) measures the percentage a company earns on its shareholders' equity and long-term debt obligations. When a company's return on total capital goes up, there should also be an increase in the return on shareholders' equity (see below). If not, it simply means that the company is borrowing more and paying interest, but not earning more for the stockholders on their equity in the company's assets. Unless a company can earn more than the interest cost of its debt over time, the risk of borrowing is not worthwhile.

Return on Shareholders' Equity (21st line) reveals how much has been earned (in percentage terms) every year for the stockholders (common and preferred). Higher figures are usually desirable, often indicating greater productivity and efficiency. Johnson & Johnson's percent earned on net worth reached a peak in 2008, however it declined sharply since then, and it is likely to be about 22% in 2013.

Trends in both this ratio and the return on total capital—two key gauges of corporate performance—say a great deal about the skill of management.

Retained to Common Equity (22nd line) also known as the "plowback ratio," is net income less all dividends (common and preferred), divided by common shareholders' equity and is expressed as a percentage. It measures the extent to which a company has internally generated resources to invest for future growth. A high plowback ratio and rapidly growing book value are positive investment characteristics.

All Dividends to Net Profit, or "payout ratio," (23rd line) measures the proportion of a company's profits that is distributed as dividends to all shareholders—both common and preferred. Young, fast-growing firms reinvest most of their profits internally. Mature firms are better able to pay out a large share of earnings. Johnson & Johnson paid out 46% of its profits in the form of cash dividends in 2012. By way of comparison, the typical large company in the *Value Line* universe usually pays out about 25%-30% of its profits in dividends.

VI: A HANDS ON TOUR OF THE VALUE LINE RESEARCH REPORT

Now that you have had a quick overview of the most important aspects of the *Value Line* report, it is time to actually use the data. You will find both explanations and questions to help you get a "hands on" feel for using a *Value Line* report. Each "question" has a blank line for you to place your answer. You may need a calculator to find some of the answers.

The questions are based on the sample page included with your welcome package. There is an answer sheet and a scoring guide at the end of the workbook, so you can see how much you have learned and the sections to which you may need to pay more attention. This is meant to be an educational and fun experience, so don't feel bad if you get something wrong—simply take some extra time to figure out what the right answer should have been.

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1. Across the top of the page are: the **company's name**, followed by the **stock exchange** on which the stock is traded— usually the New York Stock Exchange (NYSE), American Stock Exchange (ASE), or NASDAQ (NDQ), and the **ticker symbol,** usually two to four letters used to identify a stock for trading purposes. Next comes the recent **stock price** *(item 5)***.**

   Johnson & Johnson's stock is traded on the _____(1).

   Its ticker symbol is _____(1a).

2. To the right of the recent price is the *Value Line* **price/earnings ratio** *(item 6)*, often abbreviated as the **P/E** ratio. All price/earnings ratios are calculated by dividing the recent price of a stock by 12 months of share earnings. But there are some differences.

   Value Line calculates the ratio by dividing the recent price of a stock by the sum of the past 6-month's earnings per share and *Value Line's* estimate of the next six month's estimated earnings per share. *Value Line* believes that the use of both past and future earnings provides the most realistic picture possible.

   At the time this report was written, Johnson & Johnson's earnings for the past and current quarter —the June 2013 and September 2013 quarters *(in item 22)*—would equal $2.79 a share ($1.48 + $1.31). *Value Line* was estimating that earnings in the next six months—the December 2013 and March 2014 quarters *(in item 22)* — would total $2.72 a share ($1.23 + $1.49).

   With a recent stock price of 92.00 and 12 months earnings per share of $5.51 ($2.79 + $2.72), what is the price/earnings ratio? _____(2)

3. The trailing price/earnings ratio *(item 7)* is calculated by dividing the current price of a stock by the earnings per share actually reported for the past 12 months. This is the number used in most newspapers; the newspapers use reported earnings because those are the only numbers available to them since they do not make forecasts as *Value Line* does.

   Johnson & Johnson's actual reported earnings in the past 12 months (the September 2012, December 2012, March 2013, and June 2013 quarters) were $5.36 a share ($1.25 + $1.19 + $1.44 + $1.48). What is the stock's trailing price/earnings ratios? _____(3)

4. The **median price/earnings ratio** *(item 7)* is the middle value of a company's **P/E** ratios over the past 10 years, with certain statistical adjustments. **It shows the typical historical P/E of a stock.** (An investor cannot calculate a median P/E ratio without knowing the precise statistical adjustments *Value Line* uses.)

5. The **relative P/E ratio** *(item 8)* of a stock compares the P/E of one stock with the P/E of all the stocks in the *Value Line* universe of approximately 1,700 stocks. Our calculation of the **relative P/E ratio** is made by dividing *Value Line's* P/E of this company *(item 6)* by the median P/E of all of the approximately 1,700 stocks included in *The Value Line Investment Survey*. (The median P/E of all stocks can be found each week on the front cover of the *Summary & Index* section.)

   ***Value Line's* calculated P/E for Johnson & Johnson, shown on the top of the page, is 16.7. The P/E of the *Value Line* universe of stocks at the time the Johnson & Johnson report was published was 17.6. What is Johnson & Johnson's relative P/E ratio? _____(5)**

   Whenever a stock's relative P/E is more than 1, its own P/E is greater than that of the market. If its relative P/E is less than 1, its own P/E is less than that of the market. Is Johnson & Johnson's P/E ratio greater or less than that of the market? _____(5a)

6. A **dividend** is a payment by a company to a shareholder. It is usually in cash, and the cash is usually paid quarterly.

   The **dividend yield** *(item 10)* measures the expected cash dividend to be paid in the coming 12 months as a percent of the recent price of a stock. That is, the expected dividend is divided by the recent price of a stock to arrive at a figure that is shown as a %.

   Johnson & Johnson's dividend payment in the next four quarters is expected to be $2.74 a share. What is the stock's yield? _____(6)

7. ***Timeliness*** *(in item 1)* rank is Value Line's prediction for the expected price performance of a stock over the coming 6 to 12 months **relative** to all other stocks in the *Value Line* universe of approximately 1,700 stocks. ***Timeliness*** rank go from **1 (Highest)** to **5 (Lowest)**.

   At any one time, there is a normal distribution of ranks, so that there are:

   100 stocks ranked 1 (Highest)

   300 stocks ranked 2 (Above Average)

   900 (approx.) stocks ranked 3 (Average)

   300 stocks ranked 4 (Below Average)

   100 stocks ranked 5 (Lowest)

   Stocks with ***Timeliness*** rank of 1 or 2 are likely to be above-average performers; those with ranks of 3 are likely to be average performers; those with ranks of 4 or 5 are likely to be below-average performers.

   Johnson & Johnson's Timeliness rank is _____(7). That means that the stock's performance in the coming six to 12 months should be _____(7a).

8. The ***Safety*** rank *(in item 1)* measures the financial strength of a company and the price volatility of its stock relative to other companies and stocks in the *Value Line* universe. As with ***Timeliness*** rank, ***Safety*** rank go from 1 (Highest) to 5 (Lowest). ***Safety*** rank of 1 or 2 are most suitable for conservative investors.

   Johnson & Johnson's *Safety* rank is _____(8). Is this stock a good one for someone who wants to minimize risk? _____(8a)

9. The ***Technical*** rank *(in item 1)* uses a proprietary formula to predict short-term (3-6 months) future price returns of one stock relative to all others in the *Value Line* universe. This rank also goes from 1 (Highest) to 5 (Lowest).

   What is Johnson & Johnson's *Technical* rank? _____(9) Does this mean that Johnson & Johnson's stock is most likely to be an above-average, average, or below-average performer in the coming three to six months? _____(9a)

10. ***Beta*** *(in item 1)* measures a stock's price sensitivity to fluctuations of the market as a whole, as measured by the New York Stock Exchange Index. If a stock's ***Beta*** is 1.00, the stock should move in concert with the general market. If its ***Beta*** is 1.50, its stock price is likely to be 50% more volatile than the market. In this case, if the stock market goes up 10%, the stock should go up 15% (50% more than the market). If the market goes down 10%, this stock should go down 15%.

    If a stock's Beta is .65, the stock should be less volatile than the market. When the market goes up 10%, this stock should go up only 6.5%.

    Is Johnson & Johnson's stock likely to be more volatile, less volatile, or about the same as the market? _____(10)

11. *Value Line's* 3- to 5-year Price Projections *(item 29)* are shown in the box below ***Beta.*** The projected 3- to 5-year share price range (indicated by the High and Low numbers) is also shown as the Target Price Range *(item 11)* in the upper right hand corner of the price chart, with a pair of broken lines.

    Value Line **is forecasting that the price of Johnson & Johnson's stock 3 to 5 years from now will trade in a range between _____(11) and _____(11a).**

12. Below the Price Projections box is another box titled **Insider Decisions** *(item 28)*. This box shows decisions **to buy** stock, to exercise **options**, and to **sell** stock by "insiders" in the past nine months. It shows the number of transactions in each category each month. (Insiders are defined as officers and directors of a company, and we note that each transaction is counted separately. For instance, if an officer buys or sells stock in his company 3 times a month, the transactions are listed as 3.

    Have insiders bought stock in the past nine months? _____(12)

    Have they exercised options? _____(12a)

    Have they sold stock? _____(12b)

13. The **Institutional Decisions** box *(item 27)* shows the number of times institutions with more than $100 million of assets under management bought or sold stock of this company during the past three quarters. It also shows the total number of shares of stock in this company held by these institutions at the end of each quarter.

    Did the number of shares of Johnson & Johnson owned by institutions rise or fall in the most recent quarter? _____(13)

    Now let's look at the **Stock Price Chart** toward the top of each page.

14. The **high and low calendar year prices** of a stock are shown at the top of each chart *(item 9)*. (A calendar year is January 1st through December 31st.) The years are identified at the bottom of the chart.

    What was the price range of Johnson & Johnson's stock in 2012?

    High _____(14) Low _____(14a)

15. In the chart, the **vertical bars** *(item 3)* represent the high/low monthly price ranges for a stock. Stock splits are also indicated (2-for-1, for example, in 2001).

    How many stock splits has Johnson & Johnson had since 1999? _____(15)

16. The solid dark line in the chart is a **"Cash Flow" Line** *(item 4)*, sometimes called the **"***Value Line***."** One theory is that the price of a stock will tend to gravitate to this line. When the price of a stock gets above the line, the tendency over time will be for the price to go back down toward the line; when it gets below the line, there will be a tendency for the price to rise up to the line. (There are some stocks for which this theory has worked very well and others for which it hasn't. An investor should look at the historical price pattern of each stock and make a judgment about whether or not the theory applies to a particular stock.)

    Is Johnson & Johnson's stock price now above or below the cash flow line? _____(16)

17. The dotted line toward the bottom of the chart shows the **Relative Strength** *(item 12)* of a stock. It compares the price of a stock at any one time with the price of the *Value Line Arithmetic Index* (a good broad representation of the stock market, based on the 1,700 stocks in *The Value Line Investment Survey*). If the **Relative Strength Line** is rising, the stock price is going up more than the market, if the line is falling, the stock price is going up less.

    Did Johnson & Johnson's stock go up more, about the same, or less than the market in 2012? _____(17)

18. The **Legends** box *(item 2)* contains a number of useful items. First, it explains what the solid line and the dotted line are. Then, it shows the "multiple" of cash flow per share (shown in the statistical section below) which is used to plot the **"Cash Flow" Line**. The multiple is a number determined by an analyst to develop a line that most closely matches the actual historical prices of a stock. The box also includes the dates of **stock splits**, indicates if there are **options** traded on a stock, and explains that the **shaded bar** indicates a completed recession.

    Are there options traded on Johnson & Johnson stock? _____(18)

19. The % **Total Return box** *(item 13)* shows the historical total return of a stock (appreciation or depreciation plus any cash dividends) over the past 1, 3, and 5 years and also the total return of the *Value Line Arithmetic Index* over the same periods. The figures are not averaged or compounded.

    What was the % total return of Johnson & Johnson's stock during the past year? _____(19)

    What was the % total return of the *Value Line Arithmetic Index* during the past year? _____(19a)

    Did Johnson & Johnson's stock do better or worse than the *Value Line Index* over the past year? _____(19b)

    Did it do better or worse than the index over the past five years?_____(19c)

20. The many columns of numbers in the center of the page are in what *Value Line* calls the **Statistical Array** *(item 15)*. It is worth noting here that every time there is a stock split (2-for-1, 3-for-1, etc.) or a stock dividend (10%, 20%, etc.) all historical stock prices and per share data (sales per share, earnings per share, etc.) are adjusted for the stock splits and dividends. (In a 2-for-1 split, for example, all historical figures are divided by 2.) **Split adjustments are a universal practice** and are the primary reason why many of the numbers in one *Value Line* report may look quite different than those in an earlier report.

    There are two basic sections to the **Statistical Array**. The numbers in the top portion are all **per share** data. The numbers in the lower portion are **total** (or gross) figures. Also, the numbers to the left (prior to 2010) are **historical**, the numbers to the right **(in bold)** are **projections**.

    What were Johnson & Johnson's earnings per share in 2012? _____(20)

    What does *Value Line* expect Johnson & Johnson's average earnings per share will be in 2016-18? _____(20a)

21. The **Statistical Array** contains a great many financial numbers and ratios. They are all generally commonly used items, and they are defined in the glossary on www.valueline.com.

    There is much very useful information in the **Statistical Array**. Broadly speaking, the data allow investors to examine trends in a company's business.

    Have Johnson & Johnson's sales been rising over time? _____(21)

    Have Johnson & Johnson's sales ever fallen from one year to the next during the past 10 years? _____(21a) If so, when? _____(21b)

    Did Johnson & Johnson's Net Profit Margin (net profits after all expenses, including taxes, as a % of sales) rise, fall, or stay level in 2012? _____(21c)

    Did Johnson & Johnson's Return on Shareholders' Equity rise, fall, or stay level in 2012?_____(21d)

22. Most of the total (gross) numbers in the Statistical Array are in millions of dollars ($mill). The number 47348, for example, means $47,348,000,000; 9311 means $9,311,000,000.

What were Johnson & Johnson's sales in 2012? _____(22)

What was Johnson & Johnson's net profit in 2012? _____(22a)

23. The **Capital Structure** Box *(item 25)* shows a variety of things, including the total amount of **Debt Outstanding; Long-term Debt;** the number of **common shares** outstanding; and **Market Capitalization**.

Market Capitalization is the dollar value of common stock outstanding. It is calculated by multiplying the **number of shares** outstanding by the **price of** the stock.

The two numbers multiplied to calculate the Market Capitalization of Johnson & Johnson are _____(23) and _____(23a).

By the definitions used in *The Value Line Investment Survey:*

A Large Capitalization Issue = $5 billion or more

A Mid Capitalization Issue = $1 billion to $5 billion

A Small Capitalization Issue = less than $1 billion

Is the Market Capitalization of Johnson & Johnson, Large, Mid, or Small? _____(23b)

24. Johnson & Johnson's current assets and current liabilities (items scheduled to be converted into cash or to be paid within one year) are shown in the section called the **Current Position** *(item 24)*. It shows current assets, which include cash, receivables, and inventories, and current liabilities, which include accounts payable and debt due within one year.

How much did Johnson & Johnson have invested in inventory on 6/30/13? _____(24)

What was the total of its Current Assets? _____(24a) Current Liabilities? _____(24b)

25. The **Annual Rates** box *(item 23)* shows annual compound rates of change of a company's **sales, cash flow, earnings, dividends,** and **book value** over the past **10** and **5 years** and for **5 years** into the future.

In each case, the growth rates are calculated from a base which is the average of 3 years to an ending period which is also the average of 3 years. For example, a ten-year growth rate is calculated from a base of 1998-2000 to a base of 2008-2010.

Was Johnson & Johnson's sales growth in the past 5 years, faster, slower, or the same as its sales growth over the past 10 years? _____(25)

Does the analyst think sales growth is likely to be faster or slower in the next 5 years? _____(25a)

Was Johnson & Johnson's earnings growth in the past 5 years, faster, slower, or the same as its earnings growth over the past 10 years? _____(25b)

Does the analyst think earnings growth is likely to be faster, slower, or about even in the next 5 years? _____(25c)

26. The **Business Summary** *(item 16)* includes: a condensed summary of a company's operations, showing important products, markets, etc.; any shareholders owning more than 5% of the stock, including ESOPs (Employee Stock Ownership Plans); a company's address, telephone number, and Internet address; and other relevant information.

    How many business segments does Johnson & Johnson have? _____(26)

27. The **Analyst's Commentary** *(item 17)*, the lengthy text in the lower right portion of each report, is thought by many investors to be the most important item on the page. This is where the Value Line Analyst describes the outlook he/she sees for a company in the coming years, and, provides reasons for its investment suitability.

    After reading the commentary about Johnson & Johnson, do you think the analyst is suggesting that Johnson & Johnson stock should appeal to conservative investors? _____(27)

28. **Quarterly Sales, Earnings**, and **Dividend Data** *(items 21 and 22)* are shown in the lower left portion of each report. An examination of the trends in quarterly sales and earnings can often provide insights into changing conditions. As an example, look at **sales** in the most recently reported quarter (June) when they totaled $17,877,000,000. Then look at **sales** in the June quarter a year earlier.

    What was the % increase in sales from June 2012 to June 2013? _____(28)

    Were earnings per share in the latest reported quarter (June) higher, lower, or the same as those in the similar period a year earlier (June)? _____(28a)

29. Johnson & Johnson has had what appears to be a policy of regularly increasing its dividends. It has increased the dividend at approximately the same time in each of the past five years.

    What is the quarter (March, June, September, December) when it increased the dividend? _____(29)

30. The heading over the fourth column of numbers in the **Quarterly Sales** and **Earnings Per Share** boxes shows when a company's **fiscal year ends**.

    When does Johnson & Johnson's fiscal year end? _____(30)

31. The footnotes *(item 20)* at the bottom of each page explain a lot, including: the way earnings are reported—**basic** or **diluted; unusual gains** or **losses**; the availability of **DRIPs** (Dividend Reinvestment Plans, in which companies make it easy for shareholders to reinvest their dividends in more stock); dividend payment dates; and special explanations, as necessary.

    When is Johnson & Johnson expected to pay its next dividend? _____(31)

    Does Johnson & Johnson have a DRIP? _____(31a)

32. A variety of unique ratings *(item 19)* are shown in the box in the lower right of each report. Each of these items is defined briefly below and in more detail in *How To Invest In Common Stocks*. **Financial Strength** ratings, which measure the financial condition of a company, range from a high of A++ to a low of C. A stock's **Price Stability**, **Price Growth Persistence**, and **Earnings Predictability** ratings go from a high of 100 to a low of 5. **Price Stability** measures he variability of the price of a stock over time. **Price Growth Persistence** is a measure of stock price growth over time. **Earnings Predictability** measures the expected reliability of earnings forecasts.

In which category(ies) does Johnson & Johnson score at the very top?

_____

_____

_____ **(32)**

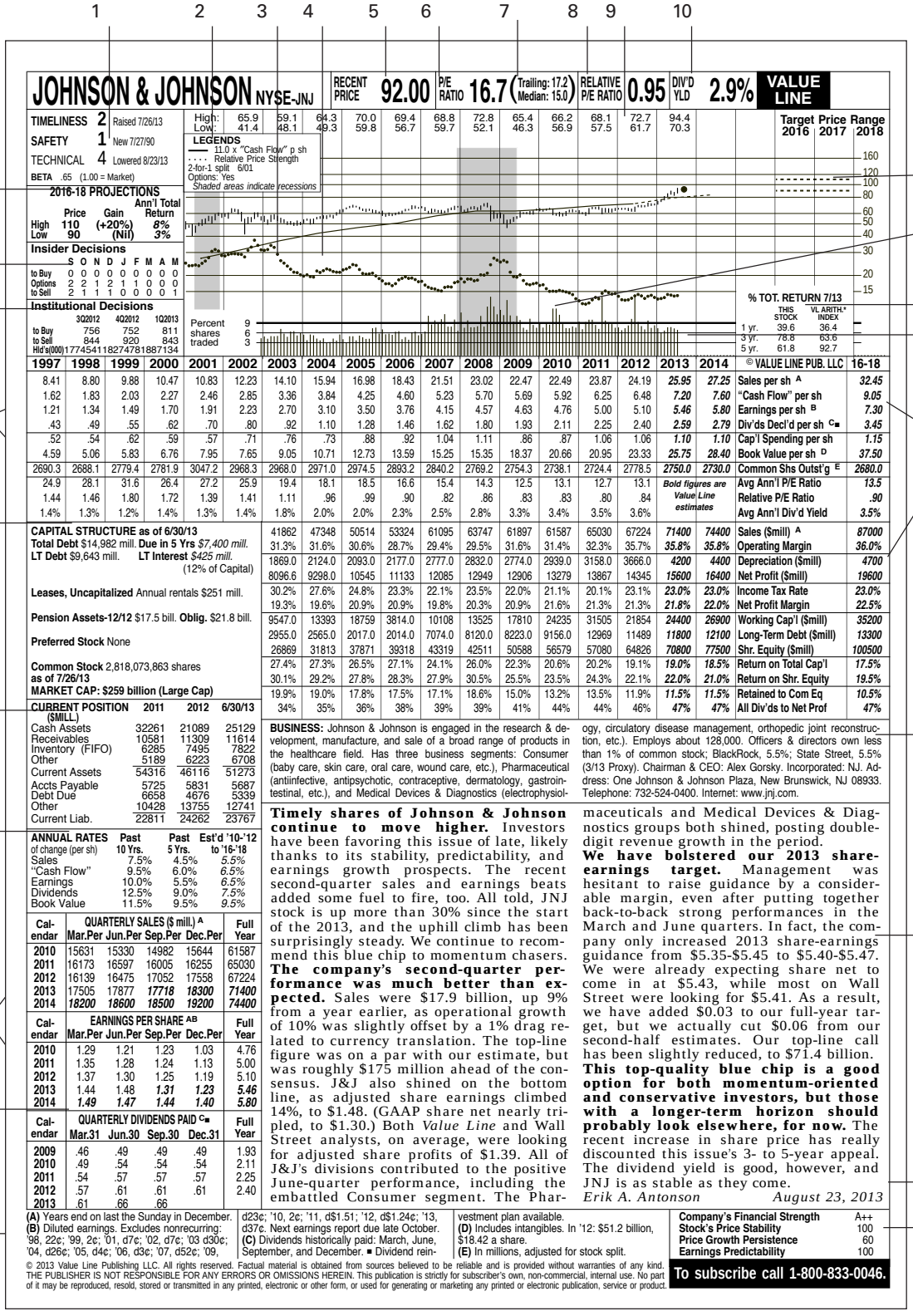
ANSWERS

1. NYSE
1a. JNJ
2. 16.7
3. 17.2
5. 0.95
5a. Less
6. 2.9%
7. 2
7a. Above Average
8. 1
8a. Yes
9. 4
9a. Below Average
10. Less Volatile
11. 110
11a. 90
12. No
12a. Yes
12b. Yes
13. Fall
14. 72.7
14a. 61.7
15. One
16. Below
17. About The Same
18. Yes
19. 39.6%
19a. 36.4%
19b. Better
19c. Worse
20. $5.10
20a. $7.30
21. Yes
21a. Yes
21b. 2009
21c. Stay Level
21d. Fall
22. $67.2 Billion
22a. $14.3 Billion
23. 2,818,073,863
23a. 92.00
23b. Large
24. $7.822 Billion
24a. $51.273 Billion
24b. $23.767 Billion
25. Slower
25a. Faster
25b. Slower
25c. Faster
26. Three
27. Yes
28. 8.5%
28a. Higher
29. June
30. December
31. December
31a. Yes
32. Financial Strength, Stock's Price Stability, Earnings Predictability

HOW DID YOU DO?

Number Wrong	Evaluation
0-3	Expert
4-6	Very Good
7-10	Passed
11 or more	You should probably restudy the workbook

VALUE LINE SAMPLE RESEARCH REPORT



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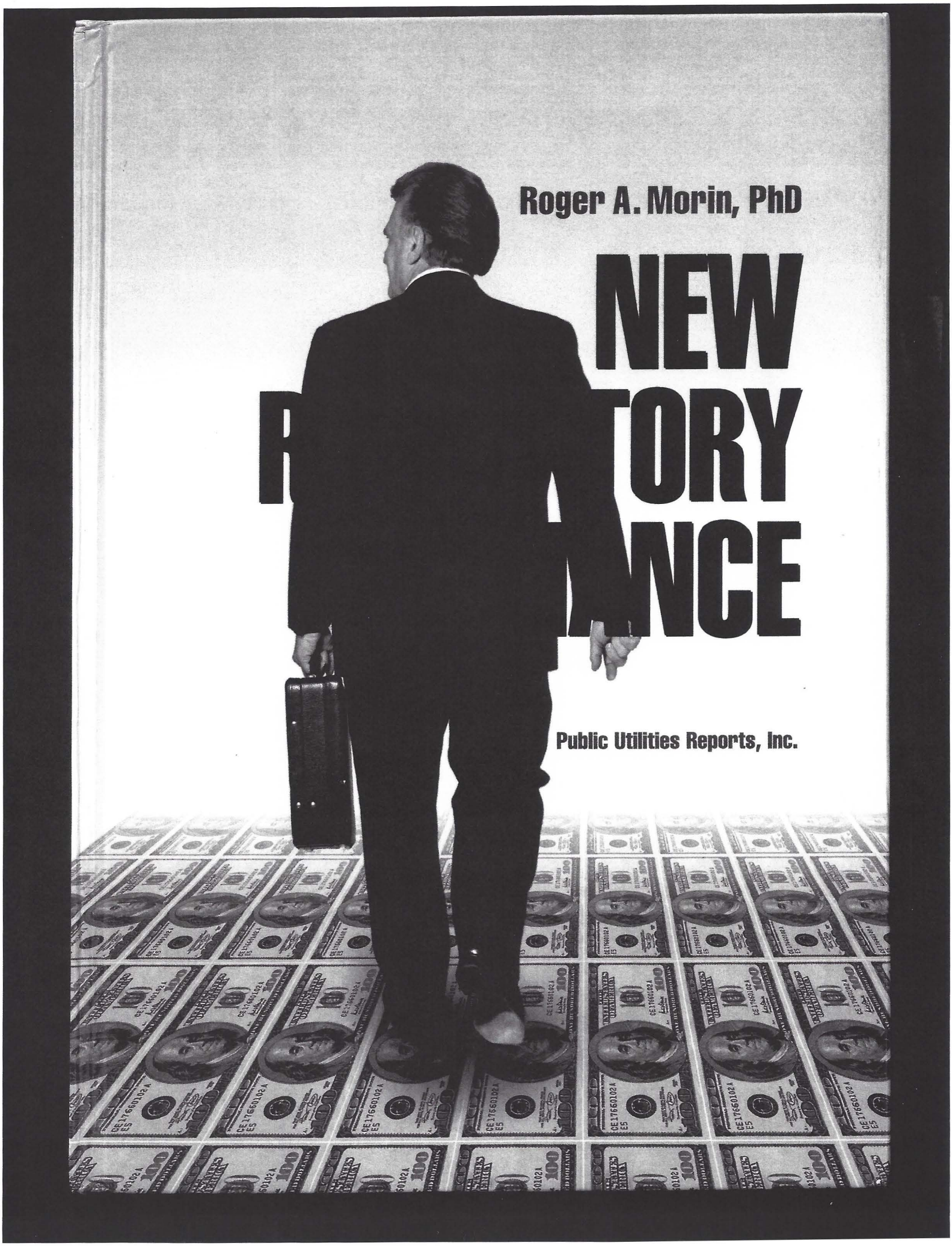
Roger A. Morin, PhD
NEW
TORY
NCE
Public Utilities Reports, Inc.

ARNINGS GROWTH	
Retained Earnings (4)	Growth Rate of Earnings (5)
$0.40	
$0.42	4%
$0.43	4%
$0.67	56%
$0.72	6%
$0.76	6%

evious year
ook value in last three years

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wth rate is expected to
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oroduce a change in the
ate growth rate which is

igs which exceeds growth
itually exceed book value
is unreasonable to expect
tors do expect a transitory
or rising earned ROE is
DCF model. A changing
1 rate DCF model is more
to change. The only way
ing an intermediate growth
rate.

al growth rates is that there
e company's risk changes.
ty that diversifies into oil
risk of electric generation
s true for a utility divesting
growth rates may be quite
to the extent that restructur-
es altered investors' growth

expectations relative to history, historical growth rates become suspect as a measure of investor expectations.

Yet another issue associated with historical growth is that reliance on history to measure investor expectations renders the replication of that growth a self-fulfilling prophecy. Reliance on forecast growth rates avoids this inherent circularity.

The major point of all this is that it is perilous to apply historical growth when a utility is in a transition between growth paths. When payout ratios, equity return, and market-to-book ratios are changing, reliance on historical growth is hazardous. Such transitions can occur under variable inflation environments, and under fundamental structural shifts, such as deregulation.

Given the choice of variables, length of historical period, and the choice of statistical methodologies, the number of permutations and combinations of historical growth rates is such that other methods and proxies for expected growth must be explored. Historical growth rates constitute a useful starting point and provide useful information as long as the necessary conditions and assumptions outlined in this section are not dramatically violated. Although historical information provides a primary foundation for expectations, investors use additional information to supplement past growth rates. Extrapolating past history alone without consideration of historical trends and anticipated economic events would assume either that past rates will persist over time or that investors' expectations are based entirely on history.

9.4 Growth Estimates: Analysts' Forecasts

Since investor growth expectations are the quantities desired in the DCF model, the use of forecast growth published by investment services merits serious consideration. The growth rates assumed by investors can be determined by a study of the analyses of future earnings and projected long-run growth rates made by the investment community. The anticipated long-run growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations.

Typically, growth forecasts are in the form of earnings per share over periods ranging from one to 5 years, and are supported by extensive financial analysis.[10]

[10] Analysts do not generally disseminate their methods of forecasting and do not generally recommend the purchase or sale of a security based on any single growth variable or growth estimating technique. A professional financial analyst is reluctant to reveal the premises and methods of his professional judgment and recommendations. Moreover, analysts' buy/sell recommendations result from complex judgments that cannot be reduced to a single variable or to simple mechanistic equations or models. Several methods and algorithms, involving both quantitative and qualitative factors, are likely to be used in arriving at a final growth forecast, including historical indicators.

The average growth rate estimate from all the analysts that follow the company measures the consensus expectation of the investment community for that company. In most cases, it is necessary to use earnings forecasts rather than dividend forecasts due to the extreme scarcity of dividend forecasts compared to the widespread availability of earnings forecasts. Given the paucity and variability of dividend forecasts, using the latter would produce unreliable DCF results. In any event, the use of the DCF model prospectively assumes constant growth in both earnings and dividends. Moreover, as discussed below, there is an abundance of empirical research that shows the validity and superiority of earnings forecasts relative to historical estimates when estimating the cost of capital.

The uniformity of growth projections is a test of whether they are typical of the market as a whole. If, for example, 10 out of 15 analysts forecast growth in the 7%–9% range, the probability is high that their analysis reflects a degree of consensus in the market as a whole. As a side note, the lack of uniformity in growth projections is a reasonable indicator of higher risk. Chapter 3 alluded to divergence of opinion amongst analysts as a valid risk indicator.

Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of g. The accuracy of these forecasts in the sense of whether they turn out to be correct is not at issue here, as long as they reflect widely held expectations. As long as the forecasts are typical and/or influential in that they are consistent with current stock price levels, they are relevant. The use of analysts' forecasts in the DCF model is sometimes denounced on the grounds that it is difficult to forecast earnings and dividends for only one year, let alone for longer time periods. This objection is unfounded, however, because it is present investors' expectations that are being priced; it is the consensus forecast that is embedded in price and therefore in required return, and not the future as it will turn out to be.

Empirical Literature on Earnings Forecasts

Published studies in the academic literature demonstrate that growth forecasts made by security analysts represent an appropriate source of DCF growth rates, are reasonable indicators of investor expectations and are more accurate than forecasts based on historical growth. These studies show that investors rely on analysts' forecasts to a greater extent than on historic data only.

Academic research confirms the superiority of analysts' earnings forecasts over univariate time-series forecasts that rely on history. This latter category

includes many *ad hoc* forecasts from statistical models, ranging from the naive methods of simple averages, moving averages, etc. to the sophisticated time-series techniques such as the Box-Jenkins modeling techniques. The literature suggests that analysts' earnings forecasts incorporate all the public information available to the analysts and the public at the time the forecasts are released. This finding implies that analysts have already factored historical growth trends into their forecast growth rates, making reliance on historical growth rates somewhat redundant and, at worst, potentially double counting growth rates which are irrelevant to future expectations. Furthermore, these forecasts are statistically more accurate than forecasts based solely on historical earnings, dividends, book value equity, and the like.

Summary of Empirical Research

Important papers include Brown and Rozeff (1978), Cragg and Malkiel (1968, 1982), Harris (1986), Vander Weide and Carleton (1988), Lys and Sohn (1990), and Easterwood and Nutt (1999).

The study by Brown and Rozeff (1978) shows that analysts, as proxied by Value Line analysts, make better forecasts than could be obtained using only historical data, because analysts have available not only past data but also a knowledge of such crucial factors as rate case decisions, construction programs, new products, cost data, and so on. Brown and Rozeff test the accuracy of analysts' forecasts versus forecasts based on past data only, and conclude that their evidence of superior analyses means that analysts' forecasts should be used in studies of cost of capital. Their evidence supports the hypothesis that Value Line analysts consistently make better predictions than historical time-series models.

Using the IBES consensus earnings forecasts as proxies for investor expectation, Harris (1986) estimates the cost of equity using expected rather than historical earnings growth rates. In his review of the literature on financial analysts' forecasts, Harris concludes that a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices. Elton, Gruber, and Gultekin (1981) show that stock prices react more to changes in analysts' forecasts of earnings than they do to changes in earnings themselves, suggesting the usefulness of analysts' forecasts as surrogates for market expectations. In an extensive National Bureau of Economic Research study using analysts' earnings forecasts, Cragg and Malkiel (1982) present detailed empirical evidence that the average analyst's expectation is more similar to expectations being reflected in the marketplace than historical growth rates, and that it is the best possible source of DCF growth rates. The authors show that historical growth rates do not contain any information that is not already impounded in analysts' growth forecasts. They conclude that the expectations formed by Wall Street professionals get quickly and thoroughly impounded

into the prices of securities and that the company valuations made by analysts are reflected in security prices.

Vander Weide and Carleton (1988) update the Cragg and Malkiel study and find overwhelming evidence that the consensus analysts' forecasts of future growth is superior to historically oriented growth measures in predicting the firm's stock price. Their results also are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions. A study by Timme and Eiseman (1989) produced similar results.

Using virtually all publicly available analyst earnings forecasts for a large sample of companies (over 23,000 individual forecasts by 100 analyst firms), Lys and Sohn (1990) show that stock returns respond to individual analyst earnings forecasts, even when they are closely preceded by earnings forecasts made by other analysts or by corporate accounting disclosures. Using actual and IBES data from 1982–1995, Easterwood and Nutt (1999) regress the analysts' forecast errors against either historical earnings changes or analysts' forecasting errors in the prior years. Results show that analysts tend to underreact to negative earnings information, but overreact to positive earnings information.

The more recent studies provide evidence that analysts make biased forecasts and misinterpret the impact of new information.[11] For example, several studies in the early 1990s suggest that analysts either systematically underreact or overreact to new information. Easterwood and Nutt (1999) discriminate between these different reactions and reported that analysts underreact to negative information, but overreact to positive information. The recent studies do not necessarily contradict the earlier literature. The earlier research focused on whether analysts' earnings forecasts are better at forecasting future earnings than historical averages, whereas the recent literature investigates whether the analysts' earnings forecasts are unbiased estimates of future earnings. It is possible that even if the analysts' forecasts are biased, they are still closer to future earnings than the historical averages, although this hypothesis has not been tested in the recent studies. One way to assess the concern that analysts' forecasts may be biased upward is to incorporate into the analysis the growth forecasts of independent research firms, such as Value Line, in addition to the analyst consensus forecast. Unlike investment banking firms and stock brokerage firms, independent research firms such as Value Line have no incentive to distort earnings growth estimates in order to bolster interest in common stocks.

[11] Other relevant papers corroborating the superiority of analysts' forecasts as predictors of future returns versus historical growth rates include: Fried and Givoly (1982), Moyer, Chatfield and Kelley (1985), and Gordon, Gordon and Gould (1989).

Some argue that analysts tend to forecast earnings growth rates that exceed those actually achieved and that this optimism biases the DCF results upward. The magnitude of the optimism bias for large rate-regulated companies in stable segments of an industry is likely to be very small. Empirically, the severity of the optimism problem is unclear for regulated utilities, if a problem exists at all. It is interesting to note that Value Line forecasts for utility companies made by independent analysts with no incentive for over- or understating growth forecasts are not materially different from those published by analysts in security firms with incentives not based on forecast accuracy, and may in fact be more robust. If the optimism problem exists at all, it can be circumvented by relying on multiple-stage DCF models that substitute long-term economic growth for analysts' growth forecasts in the second and/or third stages of the model.

Empirical studies have also been conducted showing that investors who rely primarily on data obtained from several large reputable investment research houses and security dealers obtain better results than those who do not.[12] Thus, both empirical research and common sense indicate that investors rely primarily on analysts' growth rate forecasts rather than on historical growth rates alone.

Ideally, one could decide which analysts make the most reliable forecasts and then confine the analysis to those forecasts. This would be impractical since reliable data on past forecasts are generally not available. Moreover, analysts with poor track records are replaced by more competent analysts, so that a poor forecasting record by a particular firm is not necessarily indicative of poor future forecasts. In any event, analysts working for large brokerage firms typically have a following, and investors who heed a particular analyst's recommendations do exert an influence on the market. So, an average of all the available forecasts from large reputable investment houses is likely to produce the best DCF growth rate.

Growth rate forecasts are available online from several sources. For example, Value Line Investment Analyzer, IBES (Institutional Brokers' Estimate System), Zacks Investment Research, Reuters, First Call, Yahoo Finance, and Multex Web sites provide analysts' earnings forecasts on a regular basis by reporting on the results of periodic (usually monthly) surveys of the earnings growth forecasts of a large number of investment advisors, brokerage houses, and other firms that engage in fundamental research on U.S. corporations. These firms include most large institutional investors, such as pension funds, banks, and insurance companies. Representative of industry practices, the Zacks Investment Research Web site is a central location whereby investors

[12] Examples of these studies include Stanley, Lewellen and Schlarbaum (1981) and Touche Ross Co. (1982).

are able to research the different analyst estimates for any given stock without necessarily searching for each individual analyst. Zacks gathers and compiles the different estimates made by stock analysts on the future earnings for the majority of U.S. publicly traded companies. Estimates of earnings per share for the upcoming 2 fiscal years, and a projected 5-year growth rate in such earnings per share are available at monthly intervals. The forecast 5-year growth rates are normalized in order to remove short-term distortions. Forecasts are updated when analysts formally change their stated predictions.

Exclusive reliance on a single analyst's growth forecast runs the risk of being unrepresentative of investors' consensus forecast. One would expect that averages of analysts' growth forecasts, such as those contained in IBES or Zacks, are more reliable estimates of investors' consensus expectations likely to be impounded in stock prices.[13] Averages of analysts' growth forecasts rather than a single analyst's growth forecasts are more reliable estimates of investors' consensus expectations.

One problem with the use of published analysts' forecasts is that some forecasts cover only the next one or two years. If these are abnormal years, they may not be indicative of longer-run average growth expectations. Another problem is that forecasts may not be available in sufficient quantities or may not be available at all for certain utilities, for example water utilities, in which case alternate methods of growth estimation must be employed.

Some financial economists are uncomfortable with the assumption that the DCF growth rates are perpetual growth rates, and argue that above average growth can be expected to prevail for a fixed number of years and then the growth rate will settle down to a steady-state, long-run level, consistent with that of the economy. The converse also can be true whereby below-average growth can be expected to prevail for a fixed number of years and then the growth rate will resume a higher steady-state, long-run level. Extended DCF models are available to accommodate such assumptions, and were discussed in Chapter 8.

Earnings versus Dividend Forecasts

Casual inspection of the Zacks Investment Research, First Call Thompson, and Multex Web sites reveals that earnings per share forecasts dominate the information provided. There are few, if any, dividend growth forecasts. Only Value Line provides comprehensive long-term dividend growth forecasts. The wide availability of earnings forecasts is not surprising. There is an abundance of evidence attesting to the importance of earnings in assessing investors'

[13] The earnings growth rates published by Zacks, First Call, Reuters, Value Line, and IBES contain significant overlap since all rely on virtually the same population of institutional analysts who provide such forecasts.

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expectations. The sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Surveys of analytical techniques actually used by analysts reveal the dominance of earnings and conclude that earnings are considered far more important than dividends. Finally, Value Line's principal investment rating assigned to individual stocks, Timeliness Rank, is based primarily on earnings, accounting for 65% of the ranking.

Historical Growth Rates Versus Analysts' Forecasts

Obviously, historical growth rates as well as analysts' forecasts provide relevant information to the investor with regard to growth expectations. Each proxy for expected growth brings information to the judgment process from a different light. Neither proxy is without blemish; each has advantages and shortcomings. Historical growth rates are available and easily verifiable, but may no longer be applicable if structural shifts have occurred. Analysts' growth forecasts may be more relevant since they encompass both history and current changes, but are nevertheless imperfect proxies.

9.5 Growth Estimates: Sustainable Growth Method

The third method of estimating the growth component in the DCF model, alternately referred to as the ''sustainable growth'' or ''retention ratio'' method, can be used by investment analysts to predict future growth in earnings and dividends. In this method, the fraction of earnings expected to be retained by the company, b, is multiplied by the expected return on book equity, r, to produce the growth forecast. That is,

$$g = b \times r$$

The conceptual premise of the method, enunciated in Chapter 8, Section 8.4, is that future growth in dividends for existing equity can only occur if a portion of the overall return to investors is reinvested into the firm instead of being distributed as dividends.

For example, if a company earns 12% on equity, and pays all the earnings out in dividends, the retention factor, b, is zero and earnings per share will not grow for the simple reason that there are no increments to the asset base (rate base). Conversely, if the company retains all its earnings and pays no dividends, it would grow at an annual rate of 12%. Or again, if the company earns 12% on equity and pays out 60% of the earnings in dividends, the

retention factor is 40%, and earnings growth will be 40% × 12% = 4.8% per year.

In implementing the method, both 'b' and 'r' should be the rate that the market expects to prevail in the future. If no explicit forecast of 'b' is available, it is reasonable to assume that the utility's future retention ratio will, on average, remain unchanged from its present level. Or, it can be estimated by taking a weighted average of past retention ratios as a proxy for the future on the grounds that utilities' target retention ratios are usually, although not always, stable.[14]

Both historical and forecast values of 'r' can be used to estimate g, although forecast values are superior. The use of historical realized book returns on equity rather than the expected return on equity is questionable since reliance on achieved results involves circular reasoning. Realized returns are the results of the regulatory process itself, and are also subject to tests of fairness and reasonableness. As a gauge of the expected return on book equity, either direct published analysts' forecasts of the long-run expected return on equity, or authorized rates of return in recent regulatory cases can be used as a guide. As a floor estimate, it seems reasonable for investors to expect allowed equity returns by state regulatory commissions to be in excess of the current cost of debt to the utility in question.

Another way of obtaining the expected 'r' is to examine its fundamental determinants. Since earnings per share, E, can be stated as dividends per share, D, divided by the payout ratio (1 − b), the earnings per share capitalized by investors can be inferred by dividing the current dividend by an expected payout ratio. Provided that a utility company follows a fairly stable dividend policy, the possibility of error is less when estimating the payout than when estimating the expected return on equity or the expected growth rate. Using this approach, and denoting book value per share by B, the expected return on equity is:

$$r = E/B = (D/(1 - b)) / B \qquad (9\text{-}9)$$

Estimates of the expected payout ratio can be inferred from historical 10-year average payout ratio data for utilities, assuming a stable dividend policy has been pursued. Since individual averages frequently tend to regress toward the grand mean, the historical payout ratio needs to be adjusted for this tendency, using statistical techniques for predicting future values based on this tendency of individual values to regress toward the grand mean over time.

An application of the sustainable growth method is shown in example 9-1.

[14] Statistically superior predictions of future averages are made by weighting individual past averages with the grand mean, with the variance within the individual averages and the variance across individual averages serving as weights.

40% × 12% = 4.8%

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is shown in example 9-1.

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EXAMPLE 9-1

Southeastern Electric's sustainable growth rate is required for upcoming rate case testimony. As a gauge of the expected return on equity, authorized rates of return in recent decisions for eastern U.S. electric utilities as reported by Value Line for 2005 and 2006 averaged 11%, with a standard deviation of 1%. In other words, the majority of utilities were authorized to earn 11%, with the allowed return on equity ranging from 10% to 12%. As a gauge of the expected retention ratio, the average 2006 payout ratio of 34 eastern electric utilities as compiled by Value Line was 60%, which indicates an average retention ratio of 40%, with a standard deviation of 5%. This was consistent with the long-run target retention ratio indicated by the management of Southeastern Electric. It is therefore reasonable to postulate that investors expect a retention ratio ranging from 35% to 45% for the company with a likely value of 40%. In Table 9-4 below, expected retention ratios of 35% to 45% and assumed returns on equity from 10% to 12% are multiplied to produce sustainable growth rates ranging from 3.8% to 5.4% with a likely value of 4.6%.

TABLE 9-4
SUSTAINABLE GROWTH METHOD ILLUSTRATION

Expected Retention Ratio (b)	Expected Return on Book Equity (r)		
	10%	11%	12%
35%	3.5%	3.9%	4.2%
40%	4.0%	4.4%	4.8%
45%	4.5%	5.0%	5.4%

It should be pointed out that published forecasts of the expected return on equity by analysts such as Value Line are sometimes based on end-of-period book equity rather than on average book equity. The following formula[15]

[15] The return on year-end common equity, r, is defined as $r = E/B_t$, where E is earnings per share, and B_t is the year-end book value per share. The return on average common equity, r_a, is defined as: $r_a = E/B_a$ where B_a = average book value per share. The latter is by definition: $B_a = (B_t + B_{t-1})/2$ where B_t is the year-end book equity per share and B_{t-1} is the beginning-of-year book equity per share. Dividing r by r_a and substituting:

$$\frac{r}{r_a} = \frac{E/B_t}{E/B_a} = \frac{B_a}{B_t} + \frac{B_t + B_{t-1}}{2B_t}$$

Solving for r_a, a formula for translating the return on year-end equity into the return on average equity is obtained, using reported beginning-of-the year and end-of-year common equity figures:

$$r_a = r\frac{2B_t}{B_t + B_{t-1}}$$

adjusts the reported end-of-year values so that they are based on average common equity, which is the common regulatory practice:

$$r_a = r_t \frac{2B_t}{B_t + B_{t-1}} \tag{9-10}$$

The sustainable growth method can also be extended to include external financing. From Chapter 8, the expanded growth estimate is given by:

$$g = br + sv$$

where b and r are defined as previously, s is the expected percent growth in number of shares to finance investment, and v is the profitability of the equity investment. The variable s measures the long-run expected stock financing that the utility will undertake. If the utility's investments are growing at a stable rate and if the earnings retention rate is also stable, then s will grow at a stable rate. The variable s can be estimated by taking a weighted average of past percentage increases in the number of shares. This measurement is difficult, however, owing to the sporadic and episodic nature of stock financing, and smoothing techniques must be employed. The variable v is the profitability of the equity investment and can be measured as the difference of market price and book value per share divided by the latter, as discussed in Chapter 8.

There are three problems in the practical application of the sustainable growth method. The first is that it may be even more difficult to estimate what b, r, s, and v investors have in mind than it is to estimate what g they envisage. It would appear far more economical and expeditious to use available growth forecasts and obtain g directly instead of relying on four individual forecasts of the determinants of such growth. It seems only logical that the measurement and forecasting errors inherent in using four different variables to predict growth far exceed the forecasting error inherent in a direct forecast of growth itself.

Second, there is a potential element of circularity in estimating g by a forecast of b and ROE for the utility being regulated, since ROE is determined in large part by regulation. To estimate what ROE resides in the minds of investors is equivalent to estimating the market's assessment of the outcome of regulatory hearings. Expected ROE is exactly what regulatory commissions set in determining an allowed rate of return. In other words, the method requires an estimate of return on equity before it can even be implemented. Common sense would dictate the inconsistency of a return on equity recom-

mendation that is different than the expected ROE that the method assumes the utility will earn forever. For example, using an expected return on equity of 11% to determine the growth rate and using the growth rate to recommend a return on equity of 9% is inconsistent. It is not reasonable to assume that this regulated utility company is expected to earn 11% forever, but recommend a 9% return on equity. The only way this utility can earn 11% is that rates be set by the regulator so that the utility will in fact earn 11%. One is assuming, in effect, that the company will earn a return rate exceeding the recommended cost of equity forever, but then one is recommending that a different rate be granted by the regulator. In essence, using an ROE in the sustainable growth formula that differs from the final estimated cost of equity is asking the regulator to adopt two different returns.

The circularity problem is somewhat dampened by the self-correcting nature of the DCF model. If a high equity return is granted, the stock price will increase in response to the unanticipated favorable return allowance, lowering the dividend yield component of market return in compensation for the high g induced by the high allowed return. At the next regulatory hearing, more conservative forecasts of r would prevail. The impact on the dual components of the DCF formula, yield and growth, are at least partially offsetting.

Third, the empirical finance literature discussed earlier demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock price and price/earnings ratios, as other historical growth measures or analysts' growth forecasts. Other proxies for growth, such as historical growth rates and analysts' growth forecasts, outperform retention growth estimates. See for example Timme and Eiseman (1989).

In summary, there are three proxies for the expected growth component of the DCF model: historical growth rates, analysts' forecasts, and the sustainable growth method. Criteria in choosing among the three proxies should include ease of use, ease of understanding, theoretical and mathematical correctness, and empirical validation. The latter two are crucial. The method should be logically valid and consistent, and should possess an adequate track record in predicting and explaining security value. The retention growth method is the weakest of the three proxies on both conceptual and empirical grounds. The research in this area has shown that the first two growth proxies do a better job of explaining variations in market valuation (M/B and P/E ratios) and are more highly correlated to measures of value than is the retention growth proxy.

DCF Growth Rate Check

As a reasonableness check on the DCF growth rate, the growth rate in dividends can be verified using the following relationship:[16]

Dividend Growth = Risk-free Return + Risk Premium − Dividend Yield

For example, let us say that the yield on Treasury bonds as a proxy for the risk-free return is 5%, the utility risk premium is 5.5% derived from a Capital Asset Pricing Model (CAPM) analysis discussed in earlier chapters, and the expected dividend yield for the utility industry is 4.5%. Substituting these values in the above relationship, we obtain a dividend growth expectation of 6.0% as follows:

Dividend Growth = 5.0% + 5.5% − 4.5% = 6.0%

9.6 Growth in the Non-Constant DCF Model

Although the constant growth DCF model does have a long history, analysts, practitioners, and academics have come to recognize that it is not applicable in many situations. A multiple-stage DCF model that better mirrors the pattern of future dividend growth is preferable. There is a growing consensus and ample empirical support that the best place to start is with security analysts' forecasts, that is, assume that dividend policy is relatively constant and use analyst forecasts of earnings growth as a proxy for dividend forecasts. The problem is that from the standpoint of the DCF model that extends into perpetuity, analysts' horizons are too short, typically five years. It is often unrealistic for such growth to continue into perpetuity. A transition must occur between the first stage of growth forecast by analysts for the first five years and the company's long-term sustainable growth rate. Accordingly, multiple-stage DCF models of this transition are available and were described in Chapter 8. It is useful to remember that eventually all company growth rates, especially utility services growth rates, converge to a level consistent with the growth rate of the aggregate economy.

A reasonable alternative to the constant growth DCF model is to use a multiple-stage DCF model that more appropriately captures the path of future dividend

[16] Equating the expected return from the standard DCF equation and the required return from the CAPM equation:

$$K = D_1/P + g = R_f + \text{Risk Premium}$$
$$K = D_1/P + g = R_f + \beta(R_m - R_f) \text{ from the CAPM}$$

Solving for g:

$$g = R_f + \beta(R_m - R_f) - D_1/P$$

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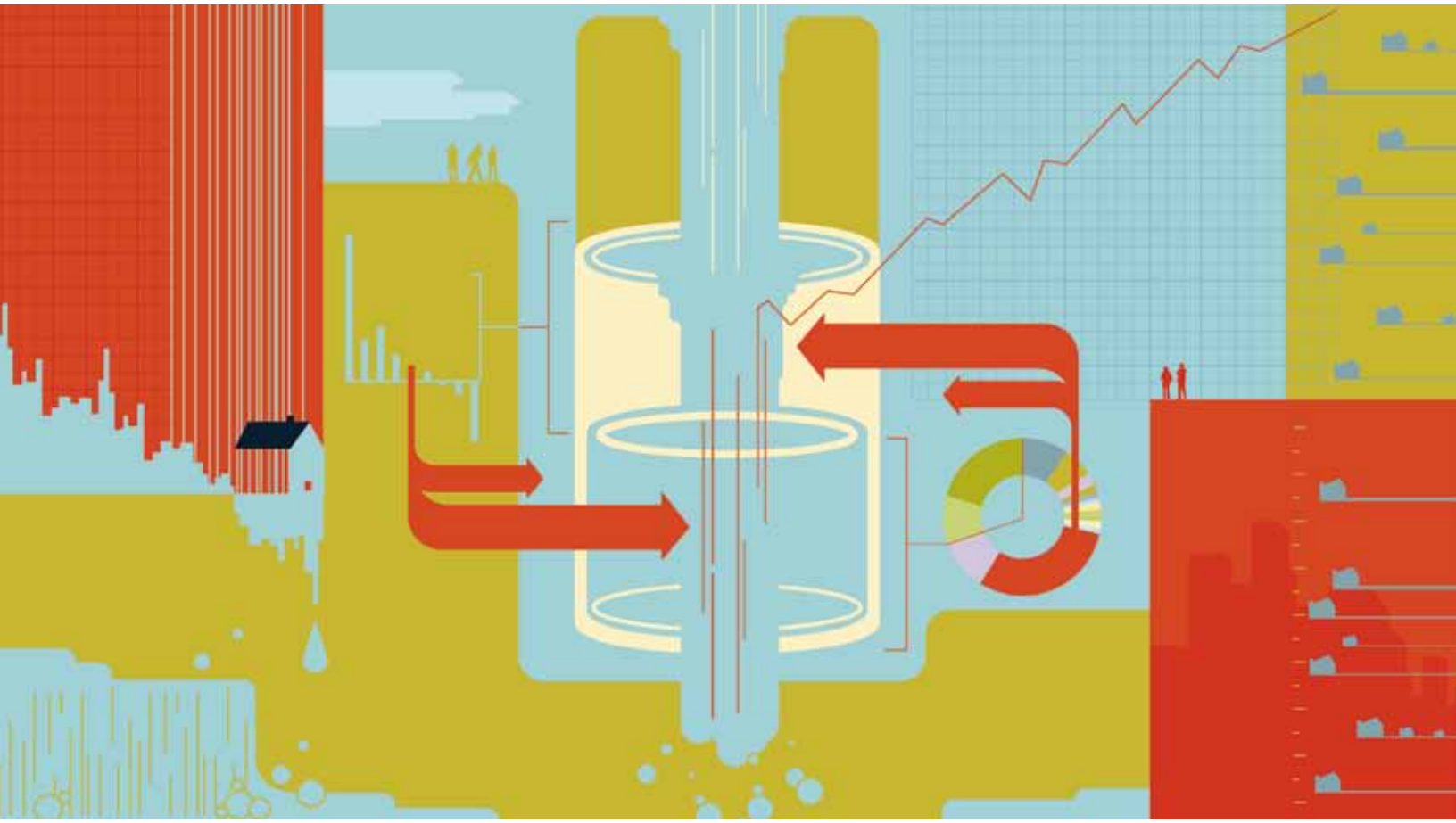
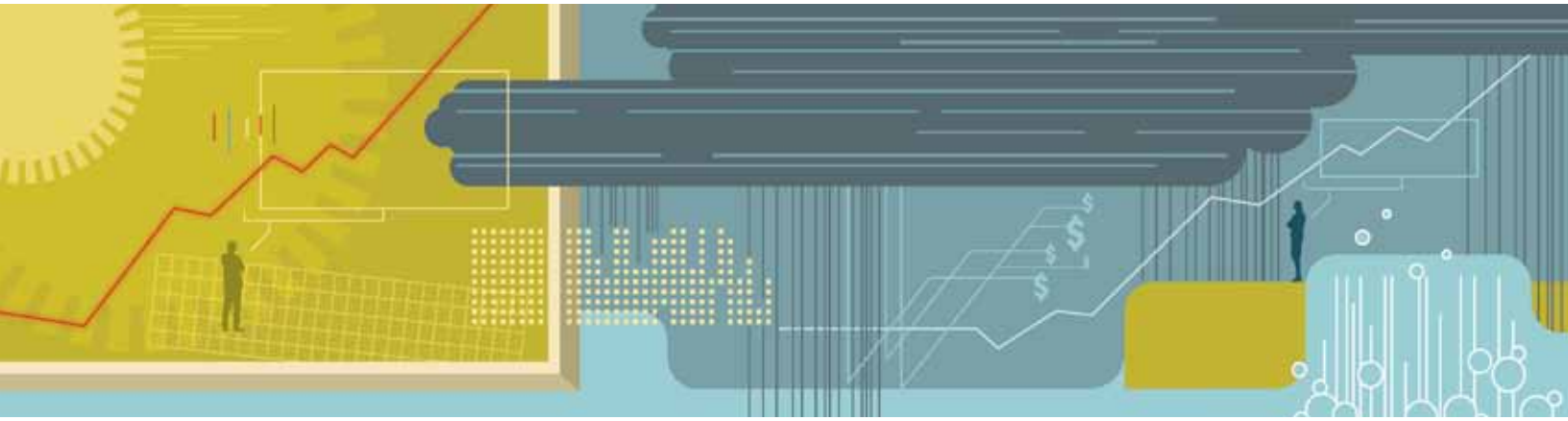




Equity analysts: Still too bullish

After almost a decade of stricter regulation, analysts' earnings forecasts continue to be excessively optimistic.

Marc H. Goedhart, Rishi Raj, and Abhishek Saxena

No executive would dispute that analysts' forecasts serve as an important benchmark of the current and future health of companies. To better understand their accuracy, we undertook research nearly a decade ago that produced sobering results. Analysts, we found, were typically overoptimistic, slow to revise their forecasts to reflect new economic conditions, and prone to making increasingly inaccurate forecasts when economic growth declined.[1]

Alas, a recently completed update of our work only reinforces this view—despite a series of rules and regulations, dating to the last decade, that were intended to improve the quality of the analysts' long-term earnings forecasts, restore investor confidence in them, and prevent conflicts of interest.[2] For executives, many of whom go to great lengths to satisfy Wall Street's expectations in their financial reporting and long-term strategic moves, this is a cautionary tale worth remembering.

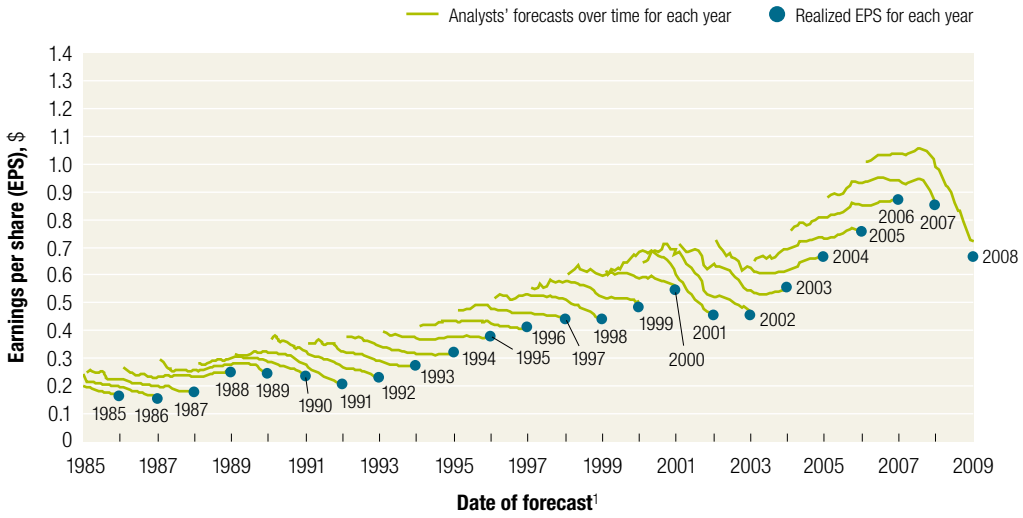
Exceptions to the long pattern of excessively optimistic forecasts are rare, as a progression of consensus earnings estimates for the S&P 500 shows (Exhibit 1). Only in years such as 2003 to 2006, when strong economic growth generated actual earnings that caught up with earlier predictions, do forecasts actually hit the mark.

Exhibit 1

Off the mark

With few exceptions, aggregate earnings forecasts exceed realized earnings per share.

S&P 500 companies



[1]Monthly forecasts.

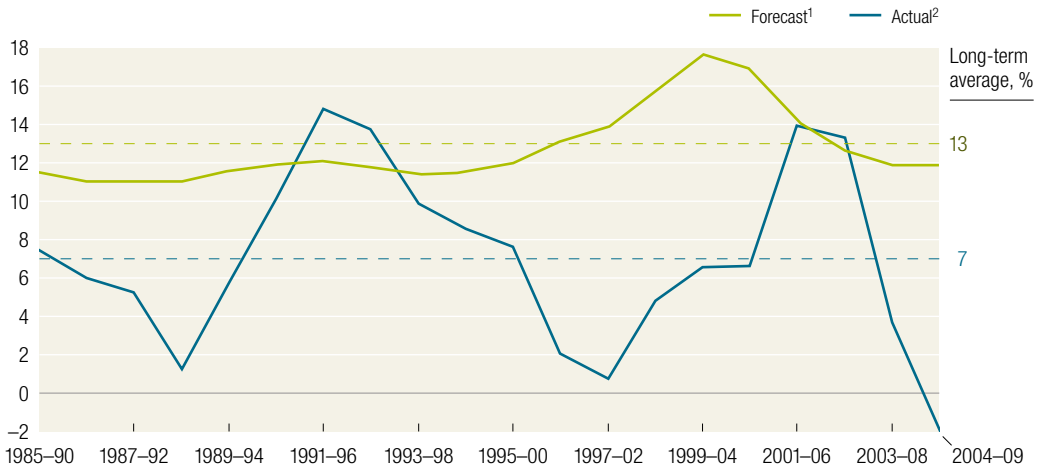
Source: Thomson Reuters I/B/E/S Global Aggregates; McKinsey analysis

Exhibit 2

Overoptimistic

Actual growth surpassed forecasts only twice in 25 years—both times during the recovery following a recession.

Earnings growth for S&P 500 companies, 5-year rolling average, %



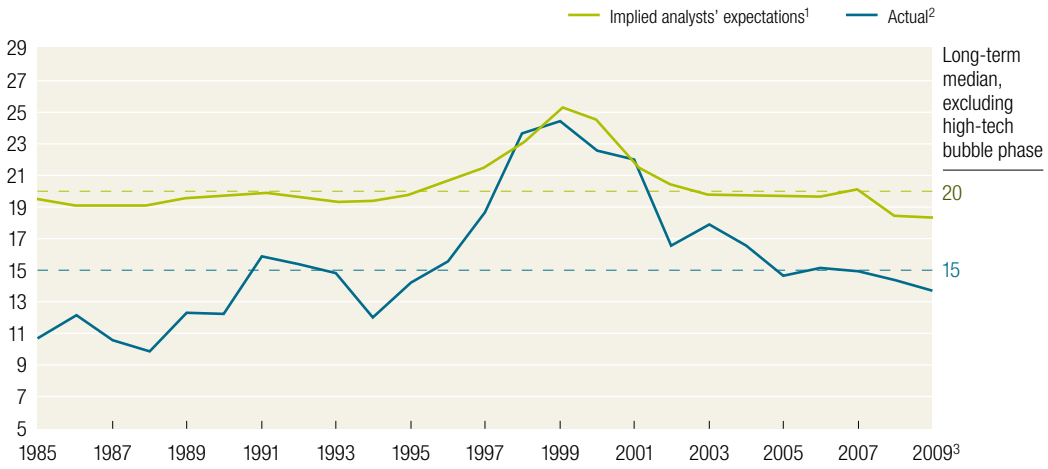
[1]Analysts' 5-year forecasts for long-term consensus earnings-per-share (EPS) growth rate. Our conclusions are same for growth based on year-over-year earnings estimates for 3 years.
[2]Actual compound annual growth rate (CAGR) of EPS; 2009 data are not yet available, figures represent consensus estimate as of Nov 2009.

Source: Thomson Reuters I/B/E/S Global Aggregates; McKinsey analysis

Exhibit 3
Less giddy

Capital market expectations are more reasonable.

Actual P/E ratio vs P/E ratio implied by analysts' forecasts, S&P 500 composite index



[1]P/E ratio based on 1-year-forward earnings-per-share (EPS) estimate and estimated value of S&P 500. Estimated value assumes: for first 5 years, EPS growth rate matches analysts' estimates then drops smoothly over next 10 years to long-term continuing-value growth rate; continuing value based on growth rate of 6%; return on equity is 13.5% (long-term historical median for S&P 500), and cost of equity is 9.5% in all periods.
[2]Observed P/E ratio based on S&P 500 value and 1-year-forward EPS estimate.
[3]Based on data as of Nov 2009.

Source: Thomson Reuters I/B/E/S Global Aggregates; McKinsey analysis

This pattern confirms our earlier findings that analysts typically lag behind events in revising their forecasts to reflect new economic conditions. When economic growth accelerates, the size of the forecast error declines; when economic growth slows, it increases.[3] So as economic growth cycles up and down, the actual earnings S&P 500 companies report occasionally coincide with the analysts' forecasts, as they did, for example, in 1988, from 1994 to 1997, and from 2003 to 2006.

Moreover, analysts have been persistently overoptimistic for the past 25 years, with estimates ranging from 10 to 12 percent a year,[4] compared with actual earnings growth of 6 percent.[5] Over this time frame, actual earnings growth surpassed forecasts in only two instances, both during the earnings recovery following a recession (Exhibit 2). On average, analysts' forecasts have been almost 100 percent too high.[6]

Capital markets, on the other hand, are notably less giddy in their predictions. Except during the market bubble of 1999–2001, actual price-to-earnings ratios have been 25 percent lower than implied P/E ratios based on analyst forecasts (Exhibit 3). What's more, an actual forward P/E ratio[7] of the S&P 500 as of November 11, 2009—14—is consistent with long-term earnings growth of 5 percent.[8] This assessment is more

reasonable, considering that long-term earnings growth for the market as a whole is unlikely to differ significantly from growth in GDP,[9] as prior McKinsey research has shown.[10] Executives, as the evidence indicates, ought to base their strategic decisions on what they see happening in their industries rather than respond to the pressures of forecasts, since even the market doesn't expect them to do so.

[1] Marc H. Goedhart, Brendan Russell, and Zane D. Williams, "Prophets and profits," mckinseyquarterly.com, October 2001.
[2] US Securities and Exchange Commission (SEC) Regulation Fair Disclosure (FD), passed in 2000, prohibits the selective disclosure of material information to some people but not others. The Sarbanes–Oxley Act of 2002 includes provisions specifically intended to help restore investor confidence in the reporting of securities' analysts, including a code of conduct for them and a requirement to disclose knowable conflicts of interest. The Global Settlement of 2003 between regulators and ten of the largest US investment firms aimed to prevent conflicts of interest between their analyst and investment businesses.
[3] The correlation between the absolute size of the error in forecast earnings growth (S&P 500) and GDP growth is –0.55.
[4] Our analysis of the distribution of five-year earnings growth (as of March 2005) suggests that analysts forecast growth of more than 10 percent for 70 percent of S&P 500 companies.
[5] Except 1998–2001, when the growth outlook became excessively optimistic.
[6] We also analyzed trends for three-year earnings-growth estimates based on year-on-year earnings estimates provided by the analysts, where the sample size of analysts' coverage is bigger. Our conclusions on the trend and the gap vis-à-vis actual earnings growth does not change.
[7] Market-weighted and forward-looking earnings-per-share (EPS) estimate for 2010.
[8] Assuming a return on equity (ROE) of 13.5 percent (the long-term historical average) and a cost of equity of 9.5 percent—the long-term real cost of equity (7 percent) and inflation (2.5 percent).
[9] Real GDP has averaged 3 to 4 percent over past seven or eight decades, which would indeed be consistent with nominal growth of 5 to 7 percent given current inflation of 2 to 3 percent.
[10] Timothy Koller and Zane D. Williams, "What happened to the bull market?" mckinseyquarterly.com, November 2001.

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Market Results Through 2017

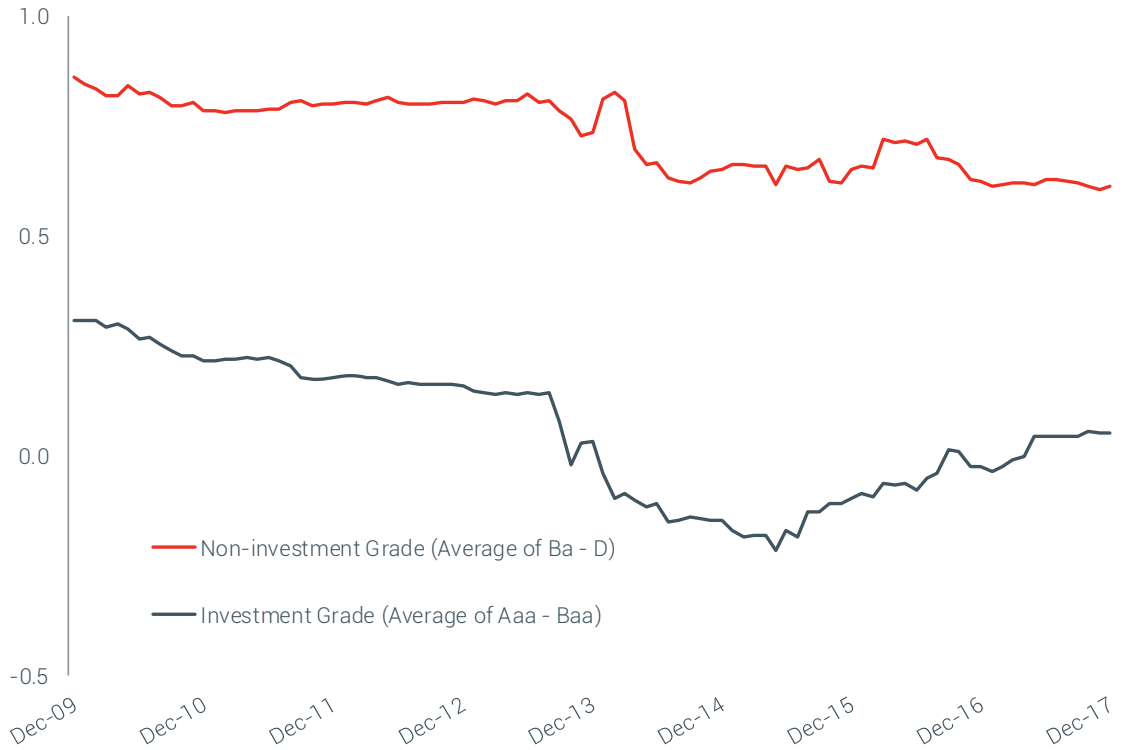
Duff & Phelps

Exhibit 5.7: Quarterly Debt Betas
Through Year-end 2017
March 2016–December 2017, Quarterly

Moody's Ratings	2016 Mar	2016 Jun	2016 Sep	2016 Dec	2017 Mar	2017 Jun	2017 Sep	2017 Dec
Aaa	-0.25	-0.26	-0.13	-0.14	-0.12	-0.04	-0.04	-0.04
Aa	-0.08	-0.09	0.00	-0.05	-0.04	0.01	0.01	0.02
A	-0.04	-0.06	0.02	-0.03	-0.02	0.03	0.03	0.04
Baa	0.13	0.11	0.18	0.13	0.13	0.18	0.18	0.19
Ba	0.36	0.35	0.34	0.33	0.33	0.37	0.36	0.38
B	0.59	0.58	0.54	0.47	0.46	0.46	0.46	0.47
Caa	0.87	0.86	0.82	0.70	0.69	0.71	0.74	0.73
Ca–D	1.06	1.04	1.00	1.00	1.00	0.97	0.92	0.88

Source of Underlying data: Barclays Global Family of Indices. Copyright 2018: Barclays Risk Analytics and Index Solutions Limited, Used with permission. Barclays Risk Analytics and Index Solutions Limited and its affiliates ("Barclays") are not responsible and shall have no liability for any conclusions, results or derived data created or otherwise from the use of any of the Barclays Indices. Corporate bond series used in analysis herein: Barclays US Corp Aaa Long TR USD, Barclays US Corp Aa Long TR USD, Barclays US Corp A Long TR USD, Barclays US Corp Baa Long TR USD , Barclays US Corp Ba Long TR USD, Barclays US Corp B Long TR USD, Barclays US Corp Caa Long TR USD, Barclays US HY Ca to D TR USD. Source: Morningstar *Direct*. Calculations by Duff & Phelps, LLC.

Exhibit 5.8: 60-month Rolling Average Debt Beta of Aaa–Baa and Debt Beta of Ba–D
December 2009–December 2017



Source of Underlying data: Barclays Global Family of Indices. Copyright 2017: Barclays Risk Analytics and Index Solutions Limited, Used with permission. Barclays Risk Analytics and Index Solutions Limited and its affiliates ("Barclays") are not responsible and shall have no liability for any conclusions, results or derived data created or otherwise from the use of any of the Barclays Indices. Corporate bond series used in analysis herein: (i) Investment grade: Barclays US Corp Aaa Long TR USD, Barclays US Corp Aa Long TR USD, Barclays US Corp A Long TR USD, Barclays US Corp Baa Long TR USD , (ii) Non-investment grade: Barclays US Corp Ba Long TR USD, Barclays US Corp B Long TR USD, Barclays US Corp Caa Long TR USD, Barclays US HY Ca to D TR USD. Source: Morningstar *Direct*.

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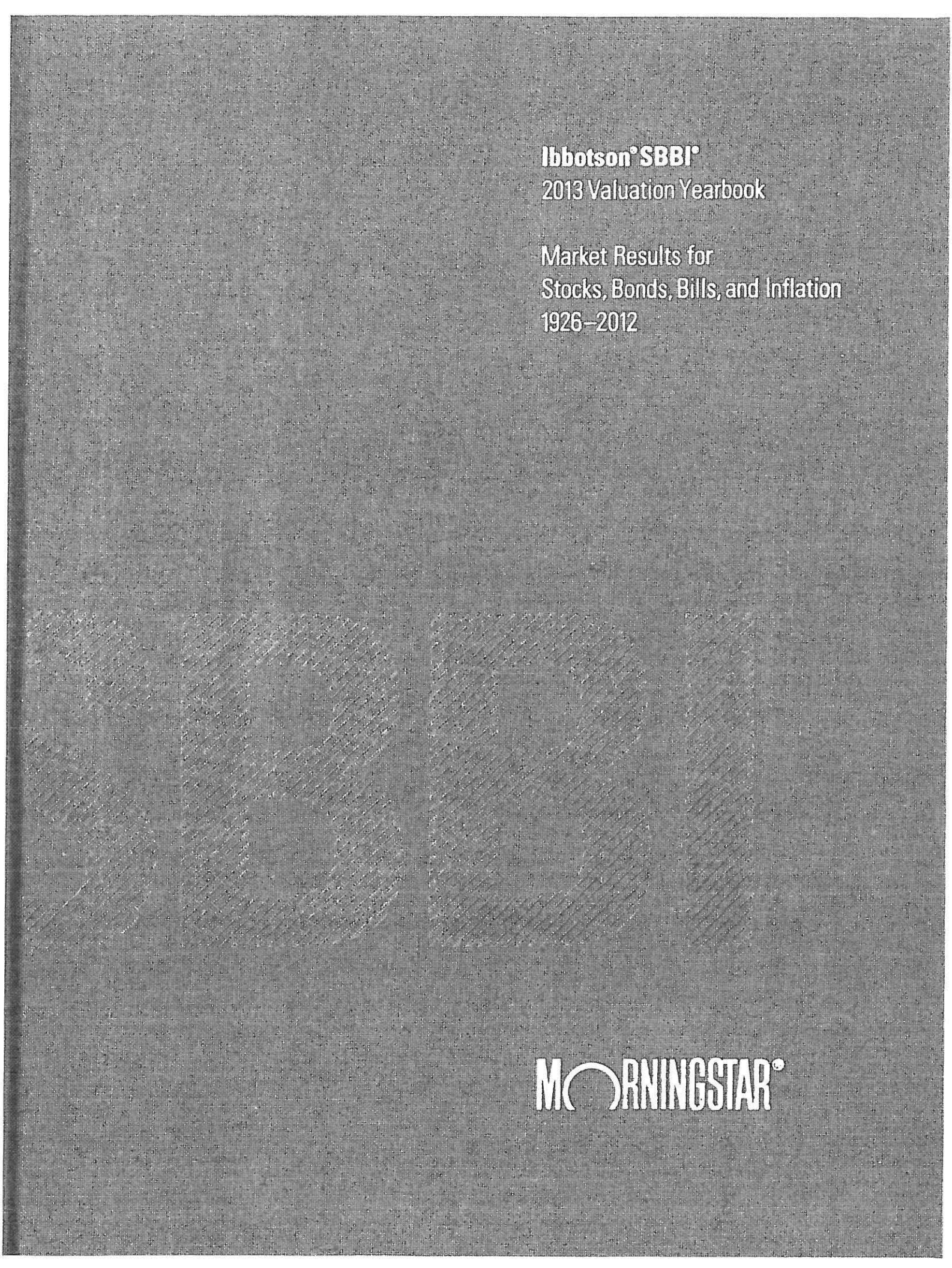
1926–2012



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The relationship between systematic risk and expected return can also be expressed mathematically. The CAPM describes the cost of equity for any company's stock as equal to the riskless rate plus an amount proportionate to the systematic risk an investor assumes.

$$k_s = r_f + (\beta_s \times ERP)$$

where:

k_s = the cost of equity for company **s**,
r_f = the expected return of the riskless asset,
β_s = the beta of the stock of company **s**; and
ERP = the expected equity risk premium, or the amount by which investors expect the future return on equities to exceed that on the riskless asset

Since the CAPM has only three variables—the expected return on the riskless asset, the beta of the stock, and the expected equity risk premium—it is one of the easiest models to implement in practice. However, an estimate of each of the above three variables must be formed. Like all components of the cost of capital, these variables should be measured on a forward-looking basis. Chapters 5 and 6 are devoted to estimating the equity risk premium and beta, respectively. Factors to consider in estimating the riskless rate are covered below.

Risk-Free Rate

In general, most valuators can agree that the risk-free rate is a forward looking rate that factors in long-term expectations on growth and inflation. The CAPM implicitly assumes the presence of a single riskless asset—that is, an asset perceived by all investors as having no risk. The ability of the U.S. government to create money to fulfill its debt obligations under virtually any scenario makes U.S. Treasury securities practically default-free. While interest rate changes cause government obligations to fluctuate in price, investors face essentially no default risk as to either coupon payment or return of principal. Asset values can vary significantly depending upon the type of risk-free interest rate selected and cash distribution characteristics of the subject asset being valued, the time horizon, and how a valuation practitioner applies this rate into his or her model.

Type of Interest Rate

A common choice for the nominal riskless rate is the yield on a U.S. Treasury security. Should the yield on a Treasury bond or a Treasury STRIPS be used to represent the riskless rate? In most cases, the yield on a Treasury coupon bond is most appropriate. If the asset being measured spins off cash periodically, the Treasury bond most closely replicates this characteristic. On the other hand, if the asset being measured provides a single payoff at the end of a specified term, the yield on a Treasury STRIPS would be more appropriate.

Time Horizon

The traditional thinking regarding the time horizon of the chosen Treasury security is that it should match the time horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury bond. Note that the horizon is a function of the investment, not the investor. If an investor plans to hold stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate, since the company will continue to exist beyond those five years.

A different vantage point of the time horizon is that the risk-free rate should best match the distribution of the periodic cash flows of the asset being valued, in which case applying a yield curve may be more appropriate.

Table 4-1: Current Yields or Expected Riskless Rates

Yield (Riskless Rate)	(%)*
Long-Term (20-year) U.S. Treasury Coupon Bond Yield	2.41
Long-Term (10-year) U.S. Treasury Coupon Bond Yield	1.78
Intermediate-Term (5-year) U.S. Treasury Coupon Note Yield	0.46
Short-term (30-day) U.S. Treasury Bill Yield	0.02

Data as of December 31, 2012
*Maturities are approximate

It is also important to note that in February 1977, the Treasury began to issue 30-year Treasury securities. Prior to this date, the longest-term Treasury security was 20 years, which was the standard Ibbotson used for its data series. To remain consistent with Ibbotson's historical data series, the *Ibbotson® Stocks, Bonds, Bills, and Inflation® Classic Yearbook* continued to base the yield

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Common academic practice in empirical studies of rates of return realized on portfolios of stocks in excess of a risk-free rate is to benchmark stock returns against realized monthly returns of "risk-free" 90-day T-bills or one-year government bonds. A T-bill rate is the purest risk-free base rate because it contains essentially no maturity risk. If inflation is high, it does reflect the inflation component, but it contains little compensation for inflation uncertainty. Problems in using such a risk-free security as a benchmark are that (1) T-bill rates may not reflect market-determined investor return requirements on long-term investments due to central bank actions affecting the short-term interest rates, and (2) rates on short-term securities tend to be more volatile than yields on longer maturities.

Long-term government bonds are free of default risk but are not "risk-free." Long-term government bonds are sensitive to future interest fluctuations. Investors are not sure of the purchasing power of the dollars they will receive upon maturity or the reinvestment rate that will be available to them to reinvest the interest payments received over the life of the bond. As a result, the long-term empirical evidence is that returns on long-term government bonds on the average exceed the returns on T-bills.[5]

The long-term premium of government bond returns in excess of the average expected interest rates on T-bills (average of future forward rates) is commonly referred to as the *horizon premium.* The horizon premium compensates the investor for the maturity risk of the bond. The horizon premium equals the added return expected *on the average* on long-term bonds due to inflation and interest rate risk. As interest rates change unexpectedly in the future, the bond price will vary. That is, bonds are subject to market risk due to unexpected changes in interest rates. The horizon premium compensates investors for that market risk.

MATCHING RISK-FREE RATE WITH ERP

In theory, when determining the risk-free rate and the matching ERP you should be matching the risk-free security and the ERP with the period in which the investment cash flows are expected. For example (where b is a risk measure for the investment):

Short-term cash flows: Current T-bill rate $+ b \times$ (*RPm* over T-bills)

Cash flows expected in:

Year 1: 1-year government bond rate $+ b \times$ (*RPm* over1-year bonds)

Year 2: 2-year forward rate on government bonds $+ b \times$ (*RPm* over 2-year bonds)

Year 3: 3-year forward rate on government bonds $+ b \times$ (*RPm*) over3-year bonds), and so on

Cash flows expected in the long-term: Current long-term government bond rate $+ b$ $\times$ (*RPm* over long-term government bonds)

MEASURING THE AVERAGE PERIOD OF THE EXPECTED CASH FLOWS

Can one measure the "average" period of expected cash flows and use an average maturity period for the risk-free security and the ERP? One measure of the length of planning horizon over which cash flows are expected is the *duration* of cash flows. We introduced the concept of duration in Chapter 6 as a measure of the effective time period over which you receive cash flows from bonds.

In a similar manner, you can calculate the expected duration of any stream of expected cash flows for any project. For valuation of a "going-concern" business, for example, assume you expect the cash flow in the first year following the valuation date of $1 million to increase at an average

[5] When short-term interest rates exceed long-term rates, the yield curve is "inverted."

Equity Risk Premiums (ERP): Determinants, Estimation and Implications – The 2014 Edition

Updated: March 2014

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Electronic copy available at: http://ssrn.com/abstract=2409198

Equity Risk Premiums (ERP): Determinants, Estimation and Implications

Equity risk premiums are a central component of every risk and return model in finance and are a key input in estimating costs of equity and capital in both corporate finance and valuation. Given their importance, it is surprising how haphazard the estimation of equity risk premiums remains in practice. We begin this paper by looking at the economic determinants of equity risk premiums, including investor risk aversion, information uncertainty and perceptions of macroeconomic risk. In the standard approach to estimating equity risk premiums, historical returns are used, with the difference in annual returns on stocks versus bonds over a long time period comprising the expected risk premium. We note the limitations of this approach, even in markets like the United States, which have long periods of historical data available, and its complete failure in emerging markets, where the historical data tends to be limited and volatile. We look at two other approaches to estimating equity risk premiums – the survey approach, where investors and managers are asked to assess the risk premium and the implied approach, where a forward-looking estimate of the premium is estimated using either current equity prices or risk premiums in non-equity markets. In the next section, we look at the relationship between the equity risk premium and risk premiums in the bond market (default spreads) and in real estate (cap rates) and how that relationship can be mined to generated expected equity risk premiums. We close the paper by examining why different approaches yield different values for the equity risk premium, and how to choose the "right" number to use in analysis.

(This is the seventh update of this piece. The first update was in the midst of the financial crisis in 2008 and there have been annual updates each year from 2009 through 2013.)

Electronic copy available at: http://ssrn.com/abstract=2409198

The notion that risk matters, and that riskier investments should have higher expected returns than safer investments, to be considered good investments, is intuitive and is central to risk and return models in finance. Thus, the expected return on any investment can be written as the sum of the riskfree rate and a risk premium to compensate for the risk. The disagreement, in both theoretical and practical terms, remains on how to measure the risk in an investment, and how to convert the risk measure into an expected return that compensates for risk. A central number in this debate is the premium that investors demand for investing in the 'average risk' equity investment (or for investing in equities as a class), i.e., the equity risk premium.

In this paper, we begin by examining competing risk and return models in finance and the role played by equity risk premiums in each of them. We argue that equity risk premiums are central components in every one of these models and consider what the determinants of these premiums might be. We follow up by looking at three approaches for estimating the equity risk premium in practice. The first is to survey investors or managers with the intent of finding out what they require as a premium for investing in equity as a class, relative to the riskfree rate. The second is to look at the premiums earned historically by investing in stocks, as opposed to riskfree investments. The third is to back out an equity risk premium from market prices today. We consider the pluses and minuses of each approach and how to choose between the very different numbers that may emerge from these approaches.

Equity Risk Premiums: Importance and Determinants

Since the equity risk premium is a key component of every valuation, we should begin by looking at not only why it matters in the first place but also the factors that influence its level at any point in time and why that level changes over time. In this section, we look at the role played by equity risk premiums in corporate financial analysis, valuation and portfolio management, and then consider the determinants of equity risk premiums.

Why does the equity risk premium matter?

The equity risk premium reflects fundamental judgments we make about how much risk we see in an economy/market and what price we attach to that risk. In the process, it affects the expected return on every risky investment and the value that we estimate for that investment. Consequently, it makes a difference in both how we allocate wealth across different asset classes and which specific assets or securities we invest in within each asset class.

A Price for Risk

To illustrate why the equity risk premium is the price attached to risk, consider an alternate (though unrealistic) world where investors are risk neutral. In this world, the value of an asset would be the present value of expected cash flows, discounted back at a risk free rate. The expected cash flows would capture the cash flows under all possible scenarios (good and bad) and there would be no risk adjustment needed. In the real world, investors are risk averse and will pay a lower price for risky cash flows than for riskless cash flows, with the same expected value. How much lower? That is where equity risk premiums come into play. In effect, the equity risk premium is the premium that investors demand for the average risk investment, and by extension, the discount that they apply to expected cash flows with average risk. When equity risk premiums rise, investors are charging a higher price for risk and will therefore pay lower prices for the same set of risky expected cash flows.

Expected Returns and Discount Rates

Building on the theme that the equity risk premium is the price for taking risk, it is a key component into the expected return that we demand for a risky investment. This expected return, is a determinant of both the cost of equity and the cost of capital, essential inputs into corporate financial analysis and valuation.

While there are several competing risk and return models in finance, they all share some common assumptions about risk. First, they all define risk in terms of variance in actual returns around an expected return; thus, an investment is riskless when actual returns are always equal to the expected return. Second, they argue that risk has to be measured from the perspective of the marginal investor in an asset, and that this marginal investor is well diversified. Therefore, the argument goes, it is only the risk that an investment adds on to a diversified portfolio that should be measured and compensated. In fact, it is this view of risk that leads us to break the risk in any investment into two components. There is a firm-specific component that measures risk that relates only to that investment or to a few investments like it, and a market component that contains risk that affects a large subset or all investments. It is the latter risk that is not diversifiable and should be rewarded.

All risk and return models agree on this fairly crucial distinction, but they part ways when it comes to how to measure this market risk. In the capital asset pricing model (CAPM), the market risk is measured with a beta, which when multiplied by the equity risk premium yields the total risk premium for a risky asset. In the competing models, such as the arbitrage pricing and multi-factor models, betas are estimated against

individual market risk factors, and each factor has it own price (risk premium). Table 1 summarizes four models, and the role that equity risk premiums play in each one:

Table 1: Equity Risk Premiums in Risk and Return Models

	Model	*Equity Risk Premium*
The CAPM	Expected Return = Riskfree Rate + $\text{Beta}_{\text{Asset}}$ (Equity Risk Premium)	Risk Premium for investing in the market portfolio, which includes all risky assets, relative to the riskless rate.
Arbitrage pricing model (APM)	$\text{Expected Return} = \text{Riskfree Rate} + \sum_{j=1}^{j=k} \beta_j (\text{Risk Premium}_j)$	Risk Premiums for individual (unspecified) market risk factors.
Multi-Factor Model	$\text{Expected Return} = \text{Riskfree Rate} + \sum_{j=1}^{j=k} \beta_j (\text{Risk Premium}_j)$	Risk Premiums for individual (specified) market risk factors
Proxy Models	Expected Return = a + b (Proxy 1) + c (Proxy 2) (where the proxies are firm characteristics such as market capitalization, price to book ratios or return momentum)	No explicit risk premium computation, but coefficients on proxies reflect risk preferences.

All of the models other than proxy models require three inputs. The first is the riskfree rate, simple to estimate in currencies where a default free entity exists, but more complicated in markets where there are no default free entities. The second is the beta (in the CAPM) or betas (in the APM or multi-factor models) of the investment being analyzed, and the third is the appropriate risk premium for the portfolio of all risky assets (in the CAPM) and the factor risk premiums for the market risk factors in the APM and multi-factor models. While I examine the issues of riskfree rate and beta estimation in companion pieces, I will concentrate on the measurement of the risk premium in this paper.

Note that the equity risk premium in all of these models is a market-wide number, in the sense that it is not company specific or asset specific but affects expected returns on all risky investments. Using a larger equity risk premium will increase the expected returns for all risky investments, and by extension, reduce their value. Consequently, the choice of an equity risk premium may have much larger consequences for value than firm-specific inputs such as cash flows, growth and even firm-specific risk measures (such as betas).

Investment and Policy Implications

It may be tempting for those not in the midst of valuation or corporate finance analysis to pay little heed to the debate about equity risk premium, but it would be a mistake to do so, since its effects are far reaching.

- The amounts set aside by both corporations and governments to meet future pension fund and health care obligations are determined by their expectations of returns from investing in equity markets, i.e., their views on the equity risk premium. Assuming that the equity risk premium is 6% will lead to far less being set aside each year to cover future obligations than assuming a premium of 4%. If the actual premium delivered by equity markets is only 2%, the fund's assets will be insufficient to meet its liabilities, leading to fund shortfalls which have to be met by raising taxes (for governments) or reducing profits (for corporations) In some cases, the pension benefits can be put at risk, if plan administrators use unrealistically high equity risk premiums, and set aside too little each year.
- Business investments in new assets and capacity is determined by whether the businesses think they can generate higher returns on those investments than the cost that they attach to the capital in that investment. If equity risk premiums increase, the cost of equity and capital will have to increase with them, leading to less overall investment in the economy and lower economic growth.
- Regulated monopolies, such as utility companies, are often restricted in terms of the prices that they charge for their products and services. The regulatory commissions that determine "reasonable" prices base them on the assumption that these companies have to earn a fair rate of return for their equity investors. To come up with this fair rate of return, they need estimates of equity risk premiums; using higher equity risk premiums will translate into higher prices for the customers in these companies.[1]
- Judgments about how much you should save for your retirement or health care and where you should invest your savings are clearly affected by how much return you think you can make on your investments. Being over optimistic about equity risk premiums will lead you to save too little to meet future needs and to over investment in risky asset classes.

Thus, the debate about equity risk premiums has implications for almost every aspect of our lives.

What are the determinants of equity risk premiums?

Before we consider different approaches for estimating equity risk premiums, we should examine the factors that determine equity risk premiums. After all, equity risk

[1] The Society of Utility and Regulatory Financial Analysts (SURFA) has annual meetings of analysts involved primarily in this debate. Not surprisingly, they spend a good chunk of their time discussing equity risk premiums, with analysts working for the utility firms arguing for higher equity risk premiums and analysts working for the state or regulatory authorities wanting to use lower risk premiums.

premiums should reflect not only the risk that investors see in equity investments but also the price they put on that risk.

Risk Aversion and Consumption Preferences

The first and most critical factor, obviously, is the risk aversion of investors in the markets. As investors become more risk averse, equity risk premiums will climb, and as risk aversion declines, equity risk premiums will fall. While risk aversion will vary across investors, it is the collective risk aversion of investors that determines equity risk premium, and changes in that collective risk aversion will manifest themselves as changes in the equity risk premium. While there are numerous variables that influence risk aversion, we will focus on the variables most likely to change over time.

a. Investor Age: There is substantial evidence that individuals become more risk averse as they get older. The logical follow up to this proposition is that markets with older investors, in the aggregate, should have higher risk premiums than markets with younger investors, for any given level of risk. Bakshi and Chen (1994), for instance, examined risk premiums in the United States and noted an increase in risk premiums as investors aged.[2] Liu and Spiegel computed the ratio of the middle-age cohort (40-49 years) to the old-age cohort (60-69) and found that PE ratios are closely and positively related to the MO ratio for the US equity market from 1954 to 2010; since the equity risk premium is inversely related to the PE, this would suggest that investor age does play a role in determining equity risk premiums.[3]
b. Preference for current consumption: We would expect the equity risk premium to increase as investor preferences for current over future consumption increase. Put another way, equity risk premiums should be lower, other things remaining equal, in markets where individuals are net savers than in markets where individuals are net consumers. Consequently, equity risk premiums should increase as savings rates decrease in an economy. Rieger, Wang and Hens (2012) compare equity risk premiums and time discount factors across 27 countries and find that premiums are higher in countries where investors are more short term.[4]

Relating risk aversion to expected equity risk premiums is not straightforward. While the direction of the relationship is simple to establish – higher risk aversion should translate

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[2] Bakshi, G. S., and Z. Chen, 1994, *Baby Boom, Population Aging, and Capital Markets*, The Journal of Business, LXVII, 165-202.

[3] Liu, Z. and M.M. Siegel, 2011, *Boomer Retirement: Headwinds for US Equity Markets?* FRBSF Economic Letters, v26.

[4] Rieger, M.O., M. Wang and T. Hens, 2012, International Evidence on the Equity Risk Premium Puzzle and Time Discounting, SSRN Working Paper, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2120442

into higher equity risk premiums- getting beyond that requires us to be more precise in our judgments about investor utility functions, specifying how investor utility relates to wealth (and variance in that wealth). As we will see later in this paper, there has been a significant angst among financial economics that most conventional utility models do not do a good job of explaining observed equity risk premiums.

Economic Risk

The risk in equities as a class comes from more general concerns about the health and predictability of the overall economy. Put in more intuitive terms, the equity risk premium should be lower in an economy with predictable inflation, interest rates and economic growth than in one where these variables are volatile. Lettau, Ludwigson and Wachter (2008) link the changing equity risk premiums in the United States to shifting volatility in the real economy.[5] In particular, they attribute that that the lower equity risk premiums of the 1990s (and higher equity values) to reduced volatility in real economic variables including employment, consumption and GDP growth. One of the graphs that they use to illustrate the correlation looks at the relationship between the volatility in GDP growth and the dividend/ price ratio (which is the loose estimate that they use for equity risk premiums), and it is reproduced in figure 1.

[5] Lettau, M., S.C. Ludvigson and J.A. Wachter, 2008. *The Declining Equity Risk Premium: What role does macroeconomic risk play?* Review of Financial Studies, v21, 1653-1687.

Figure 1: Volatility in GDP growth and Equity Risk Premiums (US)

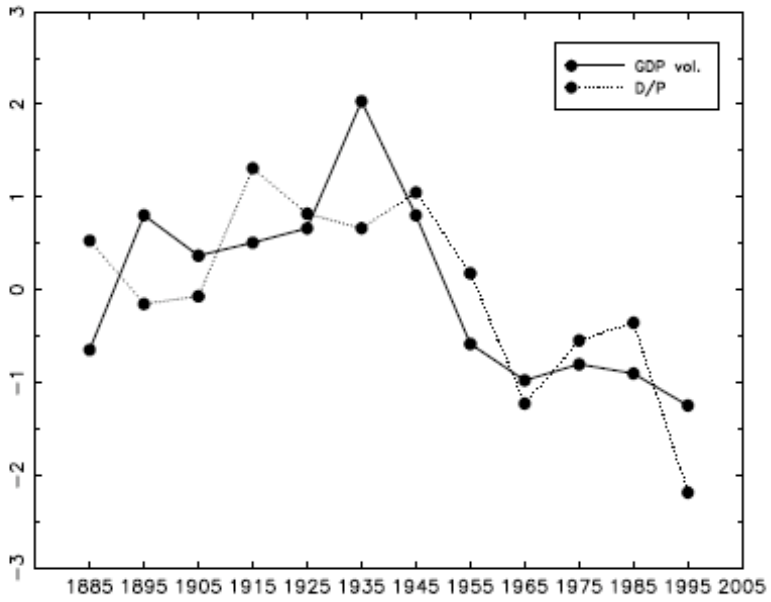

Figure 3
GDP volatility and the D/P ratio—Prewar evidence
This figure plots the standard deviations of GDP growth and the mean D/P ratio by decade starting in 1880 until 2000. Both series are demeaned and divided by their standard deviation. The GDP data are from Ray Fair's website (http://fairmodel.econ.yale.edu/RAYFAIR/PDF/2002DTBL.HTM) based on Balke and Gordon (1989). The dividend yield data is from Robert Shiller's website (http://aida.econ.yale.edu/~shiller/data/ie_data.htm).

Note how closely the dividend yield has tracked the volatility in the real economy over this very long time period.

Gollier (2001) noted that the linear absolute risk tolerance often assumed in standard models breaks down when there is income inequality and the resulting concave absolute risk tolerance should lead to higher equity risk premiums.[6] Hatchondo (2008) attempted to quantify the impact on income inequality on equity risk premiums. In his model, which is narrowly structured, the equity risk premium is higher in an economy with unequal income than in an egalitarian setting, but only by a modest amount (less than 0.50%).[7]

A related strand of research examines the relationship between equity risk premium and inflation, with mixed results. Studies that look at the relationship between the level of inflation and equity risk premiums find little or no correlation. In contrast, Brandt and Wang (2003) argue that news about inflation dominates news about real economic growth and consumption in determining risk aversion and risk premiums.[8]

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[6] Gollier, C., 2001. *Wealth Inequality and Asset Pricing*, Review of Economic Studies, v68, 181–203.
[7] Hatchondo, J.C., 2008, *A Quantitative Study of the Role of Income Inequality on Asset Prices*, Economic Quarterly, v94, 73–96.
[8] Brandt, M.W. and K.Q. Wang. 2003. *Time-varying risk aversion and unexpected inflation*,

They present evidence that equity risk premiums tend to increase if inflation is higher than anticipated and decrease when it is lower than expected. Another strand of research on the Fisher equation, which decomposes the riskfree rate into expected inflation and a real interest rate, argues that when inflation is stochastic, there should be a third component in the risk free rate: an inflation risk premium, reflecting uncertainty about future inflation.[9] Reconciling the findings, it seems reasonable to conclude that it is not so much the level of inflation that determines equity risk premiums but uncertainty about that level, and that some of the inflation uncertainty premium may be captured in the risk free rate, rather than in the equity risk premiums.

Information

When you invest in equities, the risk in the underlying economy is manifested in volatility in the earnings and cash flows reported by individual firms in that economy. Information about these changes is transmitted to markets in multiple ways, and it is clear that there have been significant changes in both the quantity and quality of information available to investors over the last two decades. During the market boom in the late 1990s, there were some who argued that the lower equity risk premiums that we observed in that period were reflective of the fact that investors had access to more information about their investments, leading to higher confidence and lower risk premiums in 2000. After the accounting scandals that followed the market collapse, there were others who attributed the increase in the equity risk premium to deterioration in the quality of information as well as information overload. In effect, they were arguing that easy access to large amounts of information of varying reliability was making investors less certain about the future.

As these contrary arguments suggest, the relationship between information and equity risk premiums is complex. More precise information should lead to lower equity risk premiums, other things remaining equal. However, precision here has to be defined in terms of what the information tells us about future earnings and cash flows. Consequently, it is possible that providing more information about last period's earnings may create more uncertainty about future earnings, especially since investors often disagree about how best to interpret these numbers. Yee (2006) defines earnings quality

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Journal of Monetary Economics, v50, pp. 1457-1498.

[9] Benninga, S., and A. Protopapadakis, 1983, *Real and Nominal Interest Rates under Uncertainty: The Fisher Problem and the Term Structure*, Journal of Political Economy, vol. 91, pp. 856–67.

in terms of volatility of future earnings and argues that equity risk premiums should increase (decrease) as earnings quality decreases (increases).[10]

Empirically, is there a relationship between earnings quality and observed equity risk premiums? The evidence is mostly anecdotal, but there are several studies that point to the deteriorating quality of earnings in the United States, with the blame distributed widely. First, the growth of technology and service firms has exposed inconsistencies in accounting definitions of earnings and capital expenditures – the treatment of R&D as an operating expense is a prime example. Second, audit firms have been accused of conflicts of interest leading to the abandonment of their oversight responsibility. Finally, the earnings game, where analysts forecast what firms will earn and firms then try to beat these forecasts has led to the stretching (and breaking) of accounting rules and standards. If earnings have become less informative in the aggregate, it stands to reason that equity investors will demand large equity risk premiums to compensate for the added uncertainty.

Information differences may be one reason why investors demand larger risk premiums in some emerging markets than in others. After all, markets vary widely in terms of transparency and information disclosure requirements. Markets like Russia, where firms provide little (and often flawed) information about operations and corporate governance, should have higher risk premiums than markets like India, where information on firms is not only more reliable but also much more easily accessible to investors. Lau, Ng and Zhang (2011) look at time series variation in risk premiums in 41 countries and conclude that countries with more information disclosure, measured using a variety of proxies, have less volatile risk premiums and that the importance of information is heightened during crises (illustrated using the 1997 Asian financial crisis and the 2008 Global banking crisis).[11]

Liquidity

In addition to the risk from the underlying real economy and imprecise information from firms, equity investors also have to consider the additional risk created by illiquidity. If investors have to accept large discounts on estimated value or pay high transactions costs to liquidate equity positions, they will be pay less for equities today (and thus demand a large risk premium).

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[10] Yee, K. K.,, 2006, *Earnings Quality and the Equity Risk Premium: A Benchmark Model*, Contemporary Accounting Research, 23: 833–877.

[11] Lau. S.T., L. Ng and B. Zhang, 2011, *Information Environment and Equity Risk Premium Volatility around the World*, Management Science, Forthcoming.

The notion that market for publicly traded stocks is wide and deep has led to the argument that the net effect of illiquidity on aggregate equity risk premiums should be small. However, there are two reasons to be skeptical about this argument. The first is that not all stocks are widely traded and illiquidity can vary widely across stocks; the cost of trading a widely held, large market cap stock is very small but the cost of trading an over-the-counter stock will be much higher. The second is that the cost of illiquidity in the aggregate can vary over time, and even small variations can have significant effects on equity risk premiums. In particular, the cost of illiquidity seems to increase when economies slow down and during periods of crisis, thus exaggerating the effects of both phenomena on the equity risk premium.

While much of the empirical work on liquidity has been done on cross sectional variation across stocks (and the implications for expected returns), there have been attempts to extend the research to look at overall market risk premiums. Gibson and Mougeot (2004) look at U.S. stock returns from 1973 to 1997 and conclude that liquidity accounts for a significant component of the overall equity risk premium, and that its effect varies over time.[12] Baekart, Harvey and Lundblad (2006) present evidence that the differences in equity returns (and risk premiums) across emerging markets can be partially explained by differences in liquidity across the markets.[13]

Catastrophic Risk

When investing in equities, there is always the potential for catastrophic risk, i.e. events that occur infrequently but can cause dramatic drops in wealth. Examples in equity markets would include the great depression from 1929-30 in the United States and the collapse of Japanese equities in the last 1980s. In cases like these, many investors exposed to the market declines saw the values of their investments drop so much that it was unlikely that they would be made whole again in their lifetimes.[14] While the possibility of catastrophic events occurring may be low, they cannot be ruled out and the equity risk premium has to reflect that risk.

Rietz (1988) uses the possibility of catastrophic events to justify higher equity risk premiums and Barro (2006) extends this argument. In the latter's paper, the catastrophic

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[12] Gibson R., Mougeot N., 2004, *The Pricing of Systematic Liquidity Risk: Empirical Evidence from the US Stock Market*. Journal of Banking and Finance, v28: 157–78.

[13] Bekaert G., Harvey C. R., Lundblad C., 2006, *Liquidity and Expected Returns: Lessons from Emerging Markets*, The Review of Financial Studies.

[14] An investor in the US equity markets who invested just prior to the crash of 1929 would not have seen index levels return to pre-crash levels until the 1940s. An investor in the Nikkei in 1987, when the index was at 40000, would still be facing a deficit of 50% (even after counting dividends) in 2008,

risk is modeled as both a drop in economic output (an economic depression) and partial default by the government on its borrowing.[15] Gabaix (2009) extends the Barro-Rietz model to allow for time varying losses in disasters.[16] Barro, Nakamura, Steinsson and Ursua (2009) use panel data on 24 countries over more than 100 years to examine the empirical effects of disasters.[17] They find that the average length of a disaster is six years and that half of the short run impact is reversed in the long term. Investigating the asset pricing implications, they conclude that the consequences for equity risk premiums will depend upon investor utility functions, with some utility functions (power utility, for instance) yielding low premiums and others generating much higher equity risk premiums. Barro and Ursua (2008) look back to 1870 and identify 87 crises through 2007, with an average impact on stock prices of about 22%, and estimate that investors would need to generate an equity risk premium of 7% to compensate for risk taken.[18] Wachter (2012) builds a consumption model, where consumption follows a normal distribution with low volatility most of the time, with a time-varying probability of disasters that explains high equity risk premiums.[19]

There have been attempts to measure the likelihood of catastrophic risk and incorporate them into models that predict equity risk premiums. In a series of papers with different co-authors, Bollerslev uses the variance risk premium, i.e., the difference between the implied variance in stock market options and realized variance, as a proxy for expectations of catastrophic risk, and documents a positive correlation with equity risk premiums.[20] Kelly (2012) and Guo, Liu, Wang, Zhou and Zuo (2013) look at extreme stock market movements as a measure of expected future jump (catastrophic) risk and find a positive link between jump risk and equity risk premiums.[21] Maheu,

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[15] Rietz, T. A., 1988, *The equity premium~: A solution*, Journal of Monetary Economics, v22, 117-131; Barro R J., 2006, *Rare Disasters and Asset Markets in the Twentieth Century*, Quarterly Journal of Economics, August, 823-866.

[16]Gabaix, Xavier, 2012, *Variable Rare Disasters: An Exactly Solved Framework for Ten Puzzles in Macro-Finance*, The Quarterly Journal of Economics, v127, 645-700.

[17] Barro, R., E. Nakamura, J. Steinsson and J. Ursua, 2009, *Crises and Recoveries in an Empirical Model of Consumption Disasters*, Working Paper, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1594554.

[18] Barro, R. and J. Ursua, 2008, Macroeconomic Crises since 1870, Working Paper, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1124864.

[19] Wachter, J.A., 2013, *Can time-varying risk of rare disasters explain aggregate stock market volatility?* Journal of Finance, v68, 987-1035.

[20] Bollerslev, T. M., T. H. Law, and G. Tauchen, 2008, *Risk, Jumps, and Diversification*, Journal of Econometrics, 144, 234-256; Bollerslev, T. M., G. Tauchen, and H. Zhou, 2009, *Expected Stock Returns and Variance Risk Premia*, Review of Financial Studies, 101-3, 552-573; Bollerselv, T.M., and V. Todorov, 2011, *Tails, Fears, and Risk Premia*, Journal of Finance, 66-6, 2165-2211.

[21] Kelly, B., 2012, *Tail Risk and Asset Prices*, Working Paper, University of Chicago; Guo, H., Z. Liu, K. Wang, H. Zhou and H. Zuo, 2013, *Realized Jump Risk and Conditional Equity Risk Premium*, Working Paper.

McCurdy and Zhao (2013) used a time-varying jump-arrival process and a two-component GARCH model on US stock market data from 1926 to 2011, and estimated that each additional jump per year increased the equity risk premium by 0.1062% and that there were, on average, 34 jumps a year, leading to a jump equity risk premium of 3.61%.[22]

The banking and financial crisis of 2008, where financial and real estate markets plunged in the last quarter of the year, has provided added ammunition to this school. As we will see later in the paper, risk premiums in all markets (equity, bond and real estate) climbed sharply during the weeks of the market crisis. In fact, the series of macro crises in the last four years that have affected markets all over the world has led some to hypothesize that the globalization may have increased the frequency and probability of disasters and by extension, equity risk premiums, in all markets.

Government Policy

The prevailing wisdom, at least until 2008, was that while government policy affected equity risk premiums in emerging markets, it was not a major factor in determining equity risk premiums in developed markets. The banking crisis of 2008 and the government responses to it have changed some minds, as both the US government and European governments have made policy changes that at times have calmed markets and at other times roiled them, potentially affecting equity risk premiums.

Pastor and Veronesi (2012) argue that uncertainty about government policy can translate into higher equity risk premiums.[23] The model they develop has several testable implications. First, government policy changes will be more likely just after economic downturns, thus adding policy uncertainty to general economic uncertainty and pushing equity risk premiums upwards. Second, you should expect to see stock prices fall, on average, across all policy changes, with the magnitude of the negative returns increasing for policy changes create more uncertainty. Third, policy changes will increase stock market volatility and the correlation across stocks.

Lam and Zhang (2014) try to capture the potential policy shocks from either an unstable government (government stability) or an incompetent bureaucracy (bureaucracy quality) in 49 countries from 1995 to 2006, using two measures of policy uncertainty drawn from the international country risk guide (ICG). They do find that equity risk

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[22] Maheu, J.M., T.H. McCurdy and X. Wang, 2013, *Do Jumps Contribute to the Dynamics of the Equity Premium,* Journal of Financial Economics, v110, 457-477.

[23] Pástor, L. and P. Veronesi, 2012. *Uncertainty about Government policy and Stock Prices*. Journal of Finance 67: 1219-1264.

premiums are higher in countries with more policy risk from either factor, with more bureaucratic risk increasing the premium by approximately 8%.[24]

The behavioral/ irrational component

Investors do not always behave rationally, and there are some who argue that equity risk premiums are determined, at least partially, by quirks in human behavior. While there are several strands to this analysis, we will focus on three:

a. The Money Illusion: As equity prices declined significantly and inflation rates increased in the late 1970s, Modigliani and Cohn (1979) argued that low equity values of that period were the consequence of investors being inconsistent about their dealings with inflation. They argued that investors were guilty of using historical growth rates in earnings, which reflected past inflation, to forecast future earnings, but current interest rates, which reflected expectations of future inflation, to estimate discount rates.[25] When inflation increases, this will lead to a mismatch, with high discount rates and low cash flows resulting in asset valuations that are too low (and risk premiums that are too high). In the Modigliani-Cohn model, equity risk premiums will rise in periods when inflation is higher than expected and drop in periods when inflation in lower than expected. Campbell and Voulteenaho (2004) update the Modigliani-Cohn results by relating changes in the dividend to price ratio to changes in the inflation rate over time and find strong support for the hypothesis.[26]
b. Narrow Framing: In conventional portfolio theory, we assume that investors assess the risk of an investment in the context of the risk it adds to their overall portfolio, and demand a premium for this risk. Behavioral economists argue that investors offered new gambles often evaluate those gambles in isolation, separately from other risks that they face in their portfolio, leading them to over estimate the risk of the gamble. In the context of the equity risk premium, Benartzi and Thaler (1995) use this "narrow framing" argument to argue that investors over estimate the risk in equity, and Barberis, Huang and Santos (2001) build on this theme.[27]

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[24] Lam, S.S. and W. Zhang, 2014, *Does Policy Uncertainty matter for International Equity Markets?* Working Paper, SSRN #2297133.

[25] Modigliani, Franco and Cohn, Richard. 1979, *Inflation, Rational Valuation, and the Market*, Financial Analysts Journal, v37(3), pp. 24-44.

[26] Campbell, J.Y. and T. Vuolteenaho, 2004, *Inflation Illusion and Stock Prices,* American Economic Review, v94, 19-23.

[27] Benartzi, S. and R. Thaler, 1995, *Myopic Loss Aversion and the Equity Premium Puzzle*, Quarterly Journal of Economics; Barberis, N., M. Huang, and T. Santos, 2001, *Prospect Theory and Asset Prices*,

The Equity Risk Premium Puzzle

While many researchers have focused on individual determinants of equity risk premiums, there is a related question that has drawn almost as much attention. Are the equity risk premiums that we have observed in practice compatible with the theory? Mehra and Prescott (1985) fired the opening shot in this debate by arguing that the observed historical risk premiums (which they estimated at about 6% at the time of their analysis) were too high, and that investors would need implausibly high risk-aversion coefficients to demand these premiums.[28] In the years since, there have been many attempts to provide explanations for this puzzle:

1. Statistical artifact: The historical risk premium obtained by looking at U.S. data is biased upwards because of a survivor bias (induced by picking one of the most successful equity markets of the twentieth century). The true premium, it is argued, is much lower. This view is backed up by a study of large equity markets over the twentieth century, which concluded that the historical risk premium is closer to 4% than the 6% cited by Mehra and Prescott.[29] However, even the lower risk premium would still be too high, if we assumed reasonable risk aversion coefficients.
2. Disaster Insurance: A variation on the statistical artifact theme, albeit with a theoretical twist, is that the observed volatility in an equity market does not fully capture the potential volatility, which could include rare but disastrous events that reduce consumption and wealth substantially. Reitz, referenced earlier, argues that investments that have dividends that are proportional to consumption (as stocks do) should earn much higher returns than riskless investments to compensate for the possibility of a disastrous drop in consumption. Prescott and Mehra (1988) counter than the required drops in consumption would have to be of such a large magnitude to explain observed premiums that this solution is not viable. [30] Berkman, Jacobsen and Lee (2011) use data from 447 international political crises between 1918 and 2006 to create a crisis index and note that increases in the

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Quarterly Journal of Economics, v 116(1), 1-53.

[28] Mehra, Rajnish, and Edward C.Prescott, 1985, *The Equity Premium: A Puzzle*, Journal of Monetary Economics, v15, 145–61. Using a constant relative risk aversion utility function and plausible risk aversion coefficients, they demonstrate the equity risk premiums should be much lower (less than 1%).

[29] Dimson, E., P. March and M. Staunton, 2002, *Triumph of the Optimists*, Princeton University Press.

[30] Mehra, R. and E.C. Prescott, 1988, *The Equity Risk Premium: A Solution?* Journal of Monetary Economics, v22, 133-136.

index increase equity risk premiums, with disproportionately large impacts on the industries most exposed to the crisis.[31]

3. Taxes: One possible explanation for the high equity returns in the period after the Second World War is the declining marginal tax rate during that period. McGrattan and Prescott (2001), for instance, provide a hypothetical illustration where a drop in the tax rate on dividends from 50% to 0% over 40 years would cause equity prices to rise about 1.8% more than the growth rate in GDP; adding the dividend yield to this expected price appreciation generates returns similar to the observed equity risk premium.[32] In reality, though, the drop in marginal tax rates was much smaller and cannot explain the surge in equity risk premiums.
4. Alternative Preference Structures: There are some who argue that the equity risk premium puzzle stems from its dependence upon conventional expected utility theory to derive premiums. In particular, the constant relative risk aversion (CRRA) function used by Mehra and Prescott in their paper implies that if an investor is risk averse to variation in consumption across different states of nature at a point in time, he or she will also be equally risk averse to consumption variation across time. Epstein and Zin consider a class of utility functions that separate risk aversion (to consumption variation at a point in time) from risk aversion to consumption variation across time. They argue that individuals are much more risk averse when it comes to the latter and claim that this phenomenon explain the larger equity risk premiums.[33] Put in more intuitive terms, individuals will choose a lower and more stable level of wealth and consumption that they can sustain over the long term over a higher level of wealth and consumption that varies widely from period to period. Constantinides (1990) adds to this argument by noting that individuals become used to maintaining past consumption levels and that even small changes in consumption can cause big changes in marginal utility. The returns on stocks are correlated with consumption, decreasing in periods when people have fewer goods to consume (recessions, for instance); the additional risk explains the higher observed equity risk premiums.[34]

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[31] Berkman, H., B. Jacobsen and J. Lee, 2011, *Time-varying Disaster Risk and Stock Returns*, Journal of Financial Economics, v101, 313-332

[32] McGrattan, E.R., and E.C. Prescott. 2001, *Taxes, Regulations, and Asset Prices*, Working Paper, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=292522.

[33] Epstein, L.G., and S.E. Zin. 1991. *Substitution, Risk Aversion, and the Temporal Behavior of Consumption and Asset Returns: An Empirical Analysis*, Journal of Political Economy, v99, 263–286.

[34] Constantinides, G.M. 1990. *Habit Formation: A Resolution of the Equity Premium Puzzle*, Journal of Political Economy, v98, no. 3 (June):519–543.

5. Myopic Loss Aversion: Myopic loss aversion refers to the finding in behavioral finance that the loss aversion already embedded in individuals becomes more pronounced as the frequency of their monitoring increases. Thus, investors who receive constant updates on equity values actually perceive more risk in equities, leading to higher risk premiums. The paper that we cited earlier by Benartzi and Thaler yields estimates of the risk premium very close to historical levels using a one-year time horizon for investors with plausible loss aversion characteristics (of about 2, which is backed up by the experimental research).

In conclusion, it is not quite clear what to make of the equity risk premium puzzle. It is true that historical risk premiums are higher than could be justified using conventional utility models for wealth. However, that may tell us more about the dangers of using historical data and the failures of classic utility models than they do about equity risk premiums. In fact, the last decade of poor stock returns in the US and declining equity risk premiums may have made the equity risk premium puzzle less of a puzzle, since explaining a historical premium of 4% (the premium in 2011) is far easier than explaining a historical premium of 6% (the premium in 1999).

Estimation Approaches

There are three broad approaches used to estimate equity risk premiums. One is to survey subsets of investors and managers to get a sense of their expectations about equity returns in the future. The second is to assess the returns earned in the past on equities relative to riskless investments and use this historical premium as the expectation. The third is to attempt to estimate a forward-looking premium based on the market rates or prices on traded assets today; we will categorize these as implied premiums.

Survey Premiums

If the equity risk premium is what investors demand for investing in risky assets today, the most logical way to estimate it is to ask these investors what they require as expected returns. Since investors in equity markets number in the millions, the challenge is often finding a subset of investors that best reflects the aggregate market. In practice, se see surveys of investors, managers and even academics, with the intent of estimating an equity risk premium.

Investors

When surveying investors, we can take one of two tacks. The first is to focus on individual investors and get a sense of what they expect returns on equity markets to be in

the future. The second is to direct the question of what equities will deliver as a premium at portfolio managers and investment professionals, with the rationale that their expectations should matter more in the aggregate, since they have the most money to invest.

a. Individual Investors: The oldest continuous index of investor sentiment about equities was developed by Robert Shiller in the aftermath of the crash of 1987 and has been updated since.[35] UBS/Gallup has also polled individual investors since 1996 about their optimism about future stock prices and reported a measure of investor sentiment.[36] While neither survey provides a direct measure of the equity risk premium, they both yield broad measure of where investors expect stock prices to go in the near future. The Securities Industry Association (SIA) surveyed investors from 1999 to 2004 on the expected return on stocks and yields numbers that can be used to extract equity risk premiums. In the 2004 survey, for instance, they found that the median expected return across the 1500 U.S. investors they questioned was 12.8%, yielding a risk premium of roughly 8.3% over the treasury bond rate at that time.[37]

b. Institutional Investors/ Investment Professionals: Investors Intelligence, an investment service, tracks more than a hundred newsletters and categorizes them as bullish, bearish or neutral, resulting in a consolidated advisor sentiment index about the future direction of equities. Like the Shiller and UBS surveys, it is a directional survey that does not yield an equity risk premium. Merrill Lynch, in its monthly survey of institutional investors globally, explicitly poses the question about equity risk premiums to these investors. In its February 2007 report, for instance, Merrill reported an average equity risk premium of 3.5% from the survey, but that number jumped to 4.1% by March, after a market downturn.[38] As markets settled down in 2009, the survey premium has also settled back to 3.76% in January 2010. Through much of 2010, the survey premium stayed in a tight range (3.85% - 3.90%) but the premium climbed to 4.08% in the January 2012 update. In February 2014, the survey yielded a risk premium of 4.6%, though it may not be directly comparable to the earlier numbers because of changes in the survey.[39]

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[35] The data is available at http://bit.ly/NcgTW7.

[36] The data is available at http://www.ubs.com/us/en/wealth/misc/investor-watch.html

[37] See http://www.sifma.org/research/surveys.aspx. The 2004 survey seems to be the last survey done by SIA. The survey yielded expected stock returns of 10% in 2003, 13% in 2002, 19% in 2001, 33% in 2000 and 30% in 1999.

[38] See http://www.ml.com/index.asp?id=7695_8137_47928.

[39] Global Fund Manager Survey, Bank of America Merrill Lynch, February 2014.

While survey premiums have become more accessible, very few practitioners seem to be inclined to use the numbers from these surveys in computations and there are several reasons for this reluctance:

1. Survey risk premiums are responsive to recent stock prices movements, with survey numbers generally increasing after bullish periods and decreasing after market decline. Thus, the peaks in the SIA survey premium of individual investors occurred in the bull market of 1999, and the more moderate premiums of 2003 and 2004 occurred after the market collapse in 2000 and 2001.
2. Survey premiums are sensitive not only to whom the question is directed at but how the question is asked. For instance, individual investors seem to have higher (and more volatile) expected returns on equity than institutional investors and the survey numbers vary depending upon the framing of the question.[40]
3. In keeping with other surveys that show differences across sub-groups, the premium seems to vary depending on who gets surveyed. Kaustia, Lehtoranta and Puttonen (2011) surveyed 1,465 Finnish investment advisors and note that not only are male advisors more likely to provide an estimate but that their estimated premiums are roughly 2% lower than those obtained from female advisors, after controlling for experience, education and other factors.[41]
4. Studies that have looked at the efficacy of survey premiums indicate that if they have any predictive power, it is in the wrong direction. Fisher and Statman (2000) document the negative relationship between investor sentiment (individual and institutional) and stock returns.[42] In other words, investors becoming more optimistic (and demanding a larger premium) is more likely to be a precursor to poor (rather than good) market returns.

As technology aids the process, the number and sophistication of surveys of both individual and institutional investors will also increase. However, it is also likely that these survey premiums will be more reflections of the recent past rather than good forecasts of the future.

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[40] Asking the question "What do you think stocks will do next year?" generates different numbers than asking "What should the risk premium be for investing in stocks?"

[41] Kaustia, M., A. Lehtoranta and V. Puttonen, 2011, *Sophistication and Gender Effects in Financial Advisers Expectations*, Working Paper, Aalto University.

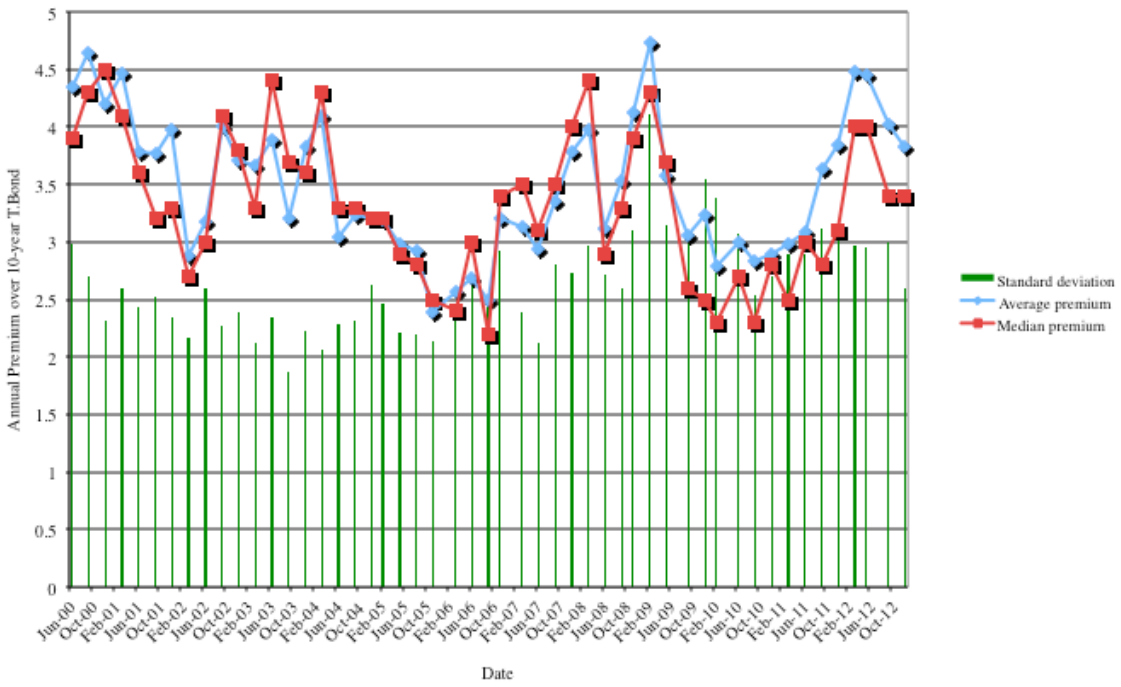
[42] Fisher, K.L., and M. Statman, 2000, *Investor Sentiment and Stock Returns*, Financial Analysts Journal, v56, 16-23.

Managers

As noted in the first section, equity risk premiums are a key input not only in investing but also in corporate finance. The hurdle rates used by companies – costs of equity and capital – are affected by the equity risk premiums that they use and have significant consequences for investment, financing and dividend decisions. Graham and Harvey have been conducting annual surveys of Chief Financial Officers (CFOs) or companies for roughly the last decade with the intent of estimating what these CFOs think is a reasonable equity risk premium (for the next 10 years over the ten-year bond rate). In their January 2013 survey, conducted over the last six months of 2012, they report an average equity risk premium of 3.83% across survey respondents, down slightly from the average premium of 3.95% a year earlier. The median premium in the January 2013 survey was 3.4%.[43]

To get a sense of how these assessed equity risk premiums have behaved over time, we have graphed the average and median values of the premium and the cross sectional standard deviation in the estimates in each CFO survey, from 2001 to 2012, in Figure 2.

Figure 2: CFO Survey Premiums



[43] Graham, J.R. and C.R. Harvey, 2013, *The Equity Risk Premium in 2013*, Working paper, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2206538. See also Graham, J.R. and C.R. Harvey, 2009, *The Equity Risk Premium amid a Global Financial Crisis*, Working paper, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1405459.

Note the survey premium peak was in February 2009, right after the crisis, at 4.74% and had its lowest recording (2.47%) in September 2006. The average across all 13 years of surveys (about 9000 responses) was 3.53%, but the standard deviation in the survey responses did surge after the 2008 crisis.

Academics

Academics are neither big players in equity markets, nor do they make many major corporate finance decisions. Notwithstanding this lack of real world impact, what they think about equity risk premiums may matter for two reasons. The first is that many of the portfolio managers and CFOs that were surveyed in the last two sub-sections received their first exposure to the equity risk premium debate in the classroom and may have been influenced by what was presented as the right risk premium in that setting. The second is that practitioners often offer academic work (textbooks and papers) as backing for the numbers that they use.

Welch (2000) surveyed 226 financial economists on the magnitude of the equity risk premium and reported interesting results. On average, economists forecast an average annual risk premium (arithmetic) of about 7% for a ten-year time horizon and 6-7% for one to five-year time horizons. As with the other survey estimates, there is a wide range on the estimates, with the premiums ranging from 2% at the pessimistic end to 13% at the optimistic end. Interestingly, the survey also indicates that economists believe that their estimates are higher than the consensus belief and try to adjust the premiums down to reflect that view.[44]

Fernandez (2010) examined widely used textbooks in corporate finance and valuation and noted that equity risk premiums varied widely across the books and that the moving average premium has declined from 8.4% in 1990 to 5.7% in 2010.[45] In a more recent survey, Fernandez, Aguirreamalloa and L. Corres (2011) compared both the level and standard deviation of equity risk premium estimates for analysts, companies and academics in the United States:[46]

Group	*Average Equity Risk Premium*	*Standard deviation in Equity Risk Premium estimates*

[44] Welch, I., 2000, *Views of Financial Economists on the Equity Premium and on Professional Controversies*, Journal of Business, v73, 501-537.

[45] Fernandez, P., 2010, *The Equity Premium in 150 Textbooks*, Working Paper, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1473225. He notes that the risk premium actually varies within the book in as many as a third of the textbooks surveyed.

[46] Fernandez, P., J. Aguirreamalloa and L. Corres, 2011, Equity Premium used in 2011 for the USA by Analysts, Companies and Professors: A Survey, Working Paper, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1805852&rec=1&srcabs=1822182.

Academics	5.6%	1.6%
Analysts	5.0%	1.1%
Companies	5.5%	1.6%

The range on equity risk premiums in use is also substantial, with a low of 1.5% and a high of 15%, often citing the same sources. The same authors also report survey responses from the same groups (academics, analysts and companies) in 82 countries in 2013 and note that those in emerging markets use higher risk premiums (not surprisingly) than those in developed markets.[47]

Historical Premiums

While our task is to estimate equity risk premiums in the future, much of the data we use to make these estimates is in the past. Most investors and managers, when asked to estimate risk premiums, look at historical data. In fact, the most widely used approach to estimating equity risk premiums is the historical premium approach, where the actual returns earned on stocks over a long time period is estimated, and compared to the actual returns earned on a default-free (usually government security). The difference, on an annual basis, between the two returns is computed and represents the historical risk premium. In this section, we will take a closer look at the approach.

Estimation Questions and Consequences

While users of risk and return models may have developed a consensus that historical premium is, in fact, the best estimate of the risk premium looking forward, there are surprisingly large differences in the actual premiums we observe being used in practice, with the numbers ranging from 3% at the lower end to 12% at the upper end. Given that we are almost all looking at the same historical data, these differences may seem surprising. There are, however, three reasons for the divergence in risk premiums: different time periods for estimation, differences in riskfree rates and market indices and differences in the way in which returns are averaged over time.

1. Time Period

Even if we agree that historical risk premiums are the best estimates of future equity risk premiums, we can still disagree about how far back in time we should go to estimate this premium. Ibbotson Associates, which is the most widely used estimation

[47] Fernandez, P., J. Aguirreamalloa and L. Corres, 2013, Market Risk Premium used in 82 countries in 2012, A Survey with 7192 Answers, SSRN #2084213.

service, has stock return data and risk free rates going back to 1926,[48] and there are other less widely used databases that go further back in time to 1871 or even to 1792.[49]

While there are many analysts who use all the data going back to the inception date, there are almost as many analysts using data over shorter time periods, such as fifty, twenty or even ten years to come up with historical risk premiums. The rationale presented by those who use shorter periods is that the risk aversion of the average investor is likely to change over time, and that using a shorter and more recent time period provides a more updated estimate. This has to be offset against a cost associated with using shorter time periods, which is the greater noise in the risk premium estimate. In fact, given the annual standard deviation in stock returns[50] between 1928 and 2013 of 20.02%, the standard error associated with the risk premium estimate can be estimated in table 2 follows for different estimation periods:[51]

Table 2: Standard Errors in Historical Risk Premiums

Estimation Period	*Standard Error of Risk Premium Estimate*
5 years	20%/ √5 = 8.94%
10 years	20%/ √10 = 6.32%
25 years	20% / √25 = 4.00%
50 years	20% / √50 = 2.83%
80 years	20% / √80 = 2.23%

Even using all of the entire Ibbotson data (about 85 years) yields a substantial standard error of 2.2%. Note that that the standard errors from ten-year and twenty-year estimates are likely to be almost as large or larger than the actual risk premium estimated. This cost of using shorter time periods seems, in our view, to overwhelm any advantages associated with getting a more updated premium.

What are the costs of going back even further in time (to 1871 or before)? First, the data is much less reliable from earlier time periods, when trading was lighter and

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[48] Ibbotson Stocks, Bonds, Bills and Inflation Yearbook (SBBI), 2011 Edition, Morningstar.

[49] Siegel, in his book, Stocks for the Long Run, estimates the equity risk premium from 1802-1870 to be 2.2% and from 1871 to 1925 to be 2.9%. (Siegel, Jeremy J., Stocks for the Long Run, Second Edition, McGraw Hill, 1998). Goetzmann and Ibbotson estimate the premium from 1792 to 1925 to be 3.76% on an arithmetic average basis and 2.83% on a geometric average basis. Goetzmann. W.N. and R. G. Ibbotson, 2005, History and the Equity Risk Premium, Working Paper, Yale University. Available at http://papers.ssrn.com/sol3/papers.cfm?abstract_id=702341.

[50] For the historical data on stock returns, bond returns and bill returns check under "updated data" in http://www.damodaran.com.

[51] The standard deviation in annual stock returns between 1928 and 2013 is 20.02%; the standard deviation in the risk premium (stock return – bond return) is a little higher at 21.72%. These estimates of the standard error are probably understated, because they are based upon the assumption that annual returns are uncorrelated over time. There is substantial empirical evidence that returns are correlated over time, which would make this standard error estimate much larger. The raw data on returns is provided in Appendix 1.

record keeping more haphazard. Second, and more important, the market itself has changed over time, resulting in risk premiums that may not be appropriate for today. The U.S. equity market in 1871 more closely resembled an emerging market, in terms of volatility and risk, than a mature market. Consequently, using the earlier data may yield premiums that have little relevance for today's markets.

There are two other solutions offered by some researchers. The first is to break the annual data down into shorter return intervals – quarters or even months – with the intent of increasing the data points over any given time period. While this will increase the sample size, the effect on the standard error will be minimal.[52] The second is to use the entire data but to give a higher weight to more recent data, thus getting more updated premiums while preserving the data. While this option seems attractive, weighting more recent data will increase the standard error of the estimate. After all, using only the last ten years of data is an extreme form of time weighting, with the data during that period being weighted at one and the data prior to the period being weighted at zero.

2. Riskfree Security and Market Index

The second estimation question we face relates to the riskfree rate. We can compare the expected return on stocks to either short-term government securities (treasury bills) or long term government securities (treasury bonds) and the risk premium for stocks can be estimated relative to either. Given that the yield curve in the United States has been upward sloping for most of the last eight decades, the risk premium is larger when estimated relative to short term government securities (such as treasury bills) than when estimated against treasury bonds.

Some practitioners and a surprising number of academics (and textbooks) use the treasury bill rate as the riskfree rate, with the alluring logic that there is no price risk in a treasury bill, whereas the price of a treasury bond can be affected by changes in interest rates over time. That argument does make sense, but only if we are interested in a single period equity risk premium (say, for next year). If your time horizon is longer (say 5 or 10 years), it is the treasury bond that provides the more predictable returns.[53] Investing in a 6-month treasury bill may yield a guaranteed return for the next six months, but rolling over this investment for the next five years will create reinvestment risk. In contrast,

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[52] If returns are uncorrelated over time, the variance in quarterly (monthly) risk premiums will be approximately one-quarter (one twelfth) the variance in annual risk premiums.

[53] For more on risk free rates, see Damodaran, A., 2008, *What is the riskfree rate?* Working Paper, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1317436.

investing in a ten-year treasury bond, or better still, a ten-year zero coupon bond will generate a guaranteed return for the next ten years.[54]

The riskfree rate chosen in computing the premium has to be consistent with the riskfree rate used to compute expected returns. Thus, if the treasury bill rate is used as the riskfree rate, the premium has to be the premium earned by stocks over that rate. If the treasury bond rate is used as the riskfree rate, the premium has to be estimated relative to that rate. For the most part, in corporate finance and valuation, the riskfree rate will be a long-term default-free (government) bond rate and not a short-term rate. Thus, the risk premium used should be the premium earned by stocks over treasury bonds.

The historical risk premium will also be affected by how stock returns are estimated. Using an index with a long history, such as the Dow 30, seems like an obvious solution, but returns on the Dow may not be a good reflection of overall returns on stocks. In theory, at least, we would like to use the broadest index of stocks to compute returns, with two caveats. The first is that the index has to be market-weighted, since the overall returns on equities will be tilted towards larger market cap stocks. The second is that the returns should be free of survivor bias; estimating returns only on stocks that have survived that last 80 years will yield returns that are too high. Stock returns should incorporate those equity investments from earlier years that did not make it through the estimation period, either because the companies in question went bankrupt or were acquired.

Finally, there is some debate about whether the equity risk premiums should be computed using nominal returns or real returns. While the choice clearly makes a difference, if we estimate the return on stocks or the government security return standing alone, it is less of an issue, when computing equity risk premiums, where we look at the difference between the two values.

3. Averaging Approach

The final sticking point when it comes to estimating historical premiums relates to how the average returns on stocks, treasury bonds and bills are computed. The arithmetic average return measures the simple mean of the series of annual returns, whereas the geometric average looks at the compounded return[55]. Many estimation services and

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[54] There is a third choice that is sometimes employed, where the short term government security (treasury bills) is used as the riskfree rate and a "term structure spread" is added to this to get a normalized long term rate.

[55] The compounded return is computed by taking the value of the investment at the start of the period ($Value_0$) and the value at the end ($Value_N$), and then computing the following:

academics argue for the arithmetic average as the best estimate of the equity risk premium. In fact, if annual returns are uncorrelated over time, and our objective was to estimate the risk premium for the next year, the arithmetic average is the best and most unbiased estimate of the premium. There are, however, strong arguments that can be made for the use of geometric averages. First, empirical studies seem to indicate that returns on stocks are negatively correlated[56] over time. Consequently, the arithmetic average return is likely to over state the premium. Second, while asset pricing models may be single period models, the use of these models to get expected returns over long periods (such as five or ten years) suggests that the estimation period may be much longer than a year. In this context, the argument for geometric average premiums becomes stronger. Indro and Lee (1997) compare arithmetic and geometric premiums, find them both wanting, and argue for a weighted average, with the weight on the geometric premium increasing with the time horizon.[57]

In closing, the averaging approach used clearly matters. Arithmetic averages will be yield higher risk premiums than geometric averages, but using these arithmetic average premiums to obtain discount rates, which are then compounded over time, seems internally inconsistent. In corporate finance and valuation, at least, the argument for using geometric average premiums as estimates is strong.

Estimates for the United States

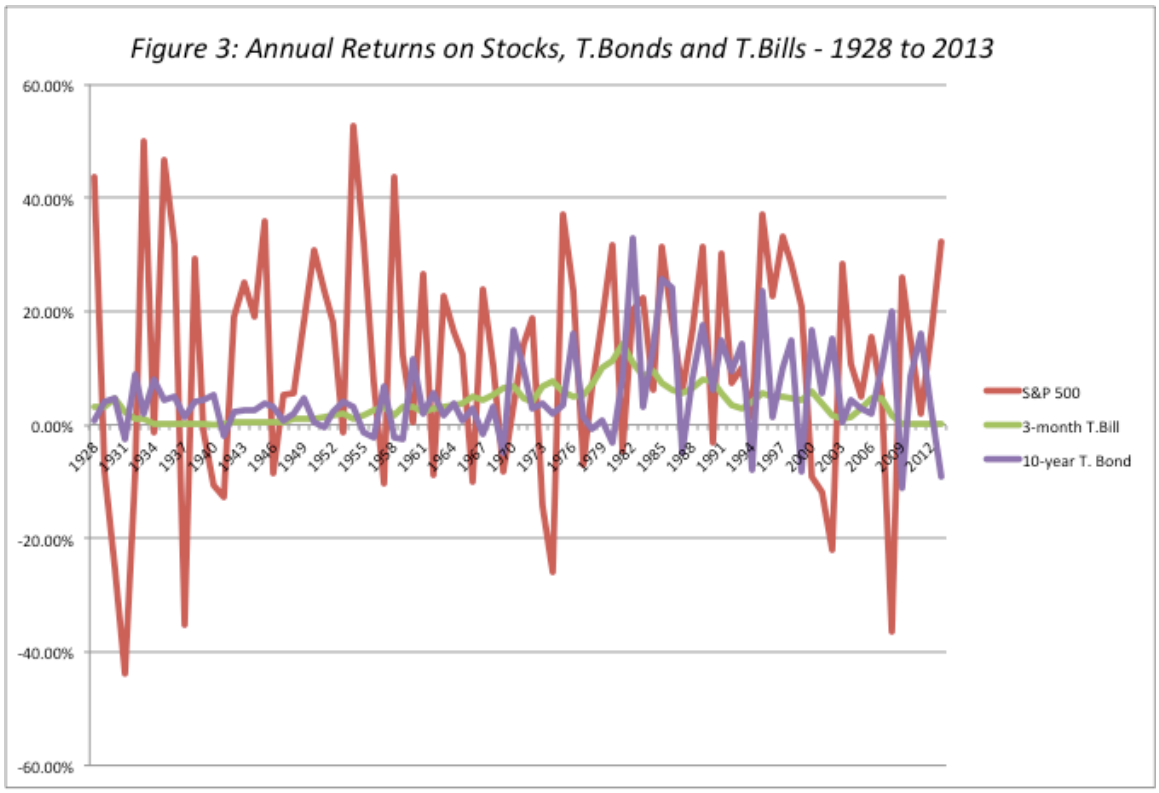
The questions of how far back in time to go, what riskfree rate to use and how to average returns (arithmetic or geometric) may seem trivial until you see the effect that the choices you make have on your equity risk premium. Rather than rely on the summary values that are provided by data services, we will use raw return data on stocks, treasury bills and treasury bonds from 1928 to 2013 to make this assessment.[58] In figure 3, we begin with a chart of the annual returns on stock, treasury bills and bonds for each year:

$$\text{Geometric Average} = \left(\frac{\text{Value}_N}{\text{Value}_0}\right)^{1/N} - 1$$

[56] In other words, good years are more likely to be followed by poor years, and vice versa. The evidence on negative serial correlation in stock returns over time is extensive, and can be found in Fama and French (1988). While they find that the one-year correlations are low, the five-year serial correlations are strongly negative for all size classes. Fama, E.F. and K.R. French, 1992, *The Cross-Section of Expected Returns*, Journal of Finance, Vol 47, 427-466.

[57] Indro, D.C. and W. Y. Lee, 1997, *Biases in Arithmetic and Geometric Averages as Estimates of Long-run Expected Returns and Risk Premium*, Financial Management, v26, 81-90.

[58] The raw data for treasury rates is obtained from the Federal Reserve data archive (http://research.stlouisfed.org/fred2/) at the Fed site in St. Louis, with the 3-month treasury bill rate used for treasury bill returns and the 10-year treasury bond rate used to compute the returns on a constant



It is difficult to make much of this data other than to state the obvious, which is that stock returns are volatile, which is at the core of the demand for an equity risk premium in the first place. In table 3, we present summary statistics for stock, 3-month Treasury bill and ten-year Treasury bond returns from 1928 to 2013:

Table 3: Summary Statistics- U.S. Stocks, T.Bills and T. Bonds- 1928-2013

	Stocks	*T. Bills*	*T. Bonds*
Mean	11.50%	3.57%	5.21%
Standard Error	2.16%	0.33%	0.85%
Median	14.52%	3.14%	3.45%
Standard Deviation	20.02%	3.06%	7.85%
Kurtosis	2.94	3.82	4.42
Skewness	-0.4	0.96	0.97
Minimum	-43.84%	0.03%	-11.12%
Maximum	52.56%	14.30%	32.81%
25th percentile	-1.20%	1.03%	1.10%
75th percentile	26.29%	5.39%	8.63%

While U.S. equities have delivered much higher returns than treasuries over this period, they have also been more volatile, as evidenced both by the higher standard deviation in

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maturity 10-year treasury bond. The stock returns represent the returns on the S&P 500. Appendix 1 provides the returns by year on stocks, bonds and bills, by year, from 1928 through the current year.

returns and by the extremes in the distribution. Using this table, we can take a first shot at estimating a risk premium by taking the difference between the average returns on stocks and the average return on treasuries, yielding a risk premium of 7.93% for stocks over T.Bills (11.50%-3.57%) and 6.29% for stocks over T.Bonds (11.50%-5.21%). Note, though, that these represent arithmetic average, long-term premiums for stocks over treasuries.

How much will the premium change if we make different choices on historical time periods, riskfree rates and averaging approaches? To answer this question, we estimated the arithmetic and geometric risk premiums for stocks over both treasury bills and bonds over different time periods in table 4, with standard errors reported in brackets below the arithmetic averages:

Table 4: Historical Equity Risk Premiums (ERP) –Estimation Period, Riskfree Rate and Averaging Approach

	Arithmetic Average		Geometric Average	
	Stocks - T. Bills	Stocks - T. Bonds	Stocks - T. Bills	Stocks - T. Bonds
1928-2013	7.93% (2.19%)	6.29% (2.34%)	6.02%	4.62%
1964-2013	6.18% (2.42%)	4.32% (2.75%)	4.83%	3.33%
2004-2013	7.55% (6.02%)	4.41% (8.66%)	5.80%	3.07%

Note that even with only three slices of history considered, the premiums range from 3.07% to 7.93%, depending upon the choices made. If we take the earlier discussion about the "right choices" to heart, and use a long-term geometric average premium over the long-term rate as the risk premium to use in valuation and corporate finance, the equity risk premium that we would use would be 4.62%. The caveats that we would offer, though, are that this estimate comes with significant standard error and is reflective of time periods (such as 1920s and 1930s) when the U.S. equity market (and investors in it) had very different characteristics.

There have been attempts to extend the historical time period to include years prior to 1926 (the start of the Ibbotson database). Goetzmann and Jorion (1999) estimate the returns on stocks and bonds between 1792 and 1925 and report an arithmetic average premium, for stocks over bonds, of 2.76% and a geometric average premium of 2.83%.[59]

[59] Jorion, Philippe and William N. Goetzmann, 1999, *Global Stock Markets in the Twentieth Century*, Journal of Finance, 54(3), 953-980.

The caveats about data reliability and changing market characteristics that we raised in an earlier section apply to these estimates.

There is one more troublesome (or at least counter intuitive) characteristic of historical risk premiums. The geometric average equity risk premium through the end of 2007 was 4.79%, higher than the 3.88% estimated though the end of 2008; in fact, every single equity risk premium number in this table would have been much higher, if we had stopped with 2007 as the last year. Adding the data for 2008, an abysmal year for stocks and a good year for bonds, lowers the historical premium dramatically, even when computed using a long period of history. In effect, the historical risk premium approach would lead investors to conclude, after one of worst stock market crisis in several decades, that stocks were less risky than they were before the crisis and that investors should therefore demand lower premiums. In contrast, adding the data for 2009, a good year for stocks (+25.94%) and a bad year for bonds (-11.12%) would have increased the equity risk premium from 3.88% to 4.29%. As a general rule, historical risk premiums will tend to rise when markets are buoyant and investors are less risk averse and will fall as markets collapse and investor fears rise.

Global Estimates

If it is difficult to estimate a reliable historical premium for the US market, it becomes doubly so when looking at markets with short, volatile and transitional histories. This is clearly true for emerging markets, where equity markets have often been in existence for only short time periods (Eastern Europe, China) or have seen substantial changes over the last few years (Latin America, India). It also true for many West European equity markets. While the economies of Germany, Italy and France can be categorized as mature, their equity markets did not share the same characteristics until recently. They tended to be dominated by a few large companies, many businesses remained private, and trading was thin except on a few stocks.

Notwithstanding these issues, services have tried to estimate historical risk premiums for non-US markets with the data that they have available. To capture some of the danger in this practice, Table 5 summarizes historical arithmetic average equity risk premiums for major non-US markets below for 1976 to 2001, and reports the standard error in each estimate:[60]

Table 5: Risk Premiums for non-US Markets: 1976- 2001

Country	*Weekly*	*Weekly standard*	*Equity Risk*	*Standard*

[60] Salomons, R. and H. Grootveld, 2003, *The equity risk premium: Emerging vs Developed Markets,* Emerging Markets Review, v4, 121-144.

	average	*deviation*	*Premium*	*error*
Canada	0.14%	5.73%	1.69%	3.89%
France	0.40%	6.59%	4.91%	4.48%
Germany	0.28%	6.01%	3.41%	4.08%
Italy	0.32%	7.64%	3.91%	5.19%
Japan	0.32%	6.69%	3.91%	4.54%
UK	0.36%	5.78%	4.41%	3.93%
India	0.34%	8.11%	4.16%	5.51%
Korea	0.51%	11.24%	6.29%	7.64%
Chile	1.19%	10.23%	15.25%	6.95%
Mexico	0.99%	12.19%	12.55%	8.28%
Brazil	0.73%	15.73%	9.12%	10.69%

Before we attempt to come up with rationale for why the equity risk premiums vary across countries, it is worth noting the magnitude of the standard errors on the estimates, largely because the estimation period includes only 25 years. Based on these standard errors, we cannot even reject the hypothesis that the equity risk premium in each of these countries is zero, let alone attach a value to that premium.

If the standard errors on these estimates make them close to useless, consider how much more noise there is in estimates of historical risk premiums for some emerging market equity markets, which often have a reliable history of ten years or less, and very large standard deviations in annual stock returns. Historical risk premiums for emerging markets may provide for interesting anecdotes, but they clearly should not be used in risk and return models.

The survivor bias

Given how widely the historical risk premium approach is used, it is surprising that the flaws in the approach have not drawn more attention. Consider first the underlying assumption that investors' risk premiums have not changed over time and that the average risk investment (in the market portfolio) has remained stable over the period examined. We would be hard pressed to find anyone who would be willing to sustain this argument with fervor. The obvious fix for this problem, which is to use a more recent time period, runs directly into a second problem, which is the large noise associated with historical risk premium estimates. While these standard errors may be tolerable for very long time periods, they clearly are unacceptably high when shorter periods are used.

Even if there is a sufficiently long time period of history available, and investors' risk aversion has not changed in a systematic way over that period, there is a final problem. Markets such as the United States, which have long periods of equity market

history, represent "survivor markets". In other words, assume that one had invested in the largest equity markets in the world in 1926, of which the United States was one.[61] In the period extending from 1926 to 2000, investments in many of the other equity markets would have earned much smaller premiums than the US equity market, and some of them would have resulted in investors earning little or even negative returns over the period. Thus, the survivor bias will result in historical premiums that are larger than expected premiums for markets like the United States, even assuming that investors are rational and factor risk into prices.

How can we mitigate the survivor bias? One solution is to look at historical risk premiums across multiple equity markets across very long time periods. In the most comprehensive attempt of this analysis, Dimson, Marsh and Staunton (2002, 2008) estimated equity returns for 17 markets and obtained both local and a global equity risk premium.[62] In their most recent update in 2014, they provide the risk premiums from 1900 to 2013 for 20 markets, with standard errors on each estimate:[63]

Table 6: Historical Risk Premiums across Equity Markets – 1900 – 2013 (in %)

	Stocks minus Short term Governments				*Stocks minus Long term Governments*			
Country	*Geometric Mean*	*Arithmetic Mean*	*Standard Error*	*Standard Deviation*	*Geometric Mean*	*Arithmetic Mean*	*Standard Error*	*Standard Deviation*
Australia	6.6%	8.2%	1.6%	17.5%	5.7%	7.6%	1.9%	20.0%
Austria	5.6%	10.5%	3.5%	37.5%	2.9%	22.0%	14.6%	154.1%
Belgium	2.9%	5.4%	2.2%	24.0%	2.4%	4.5%	2.0%	21.1%
Canada	4.2%	5.6%	1.6%	17.0%	3.5%	5.2%	1.7%	18.3%
Denmark	3.0%	4.9%	1.9%	20.6%	2.1%	3.6%	1.7%	17.9%
Finland	5.9%	9.5%	2.8%	30.0%	5.3%	8.9%	2.8%	30.2%
France	6.1%	8.7%	2.3%	24.3%	3.2%	5.5%	2.1%	22.8%
Germany	6.1%	10.0%	3.0%	31.6%	5.3%	8.7%	2.7%	28.6%
Ireland	3.4%	5.7%	2.0%	21.4%	2.6%	4.6%	1.8%	19.7%

[61] Jorion, Philippe and William N. Goetzmann, 1999, *Global Stock Markets in the Twentieth Century*, Journal of Finance, 54(3), 953-980. They looked at 39 different equity markets and concluded that the US was the best performing market from 1921 to the end of the century. They estimated a geometric average premium of 3.84% across all of the equity markets that they looked at, rather than just the US and estimated that the survivor bias added 1.5% to the US equity risk premium (with arithmetic averages) and 0.9% with geometric averages.

[62] Dimson, E.,, P Marsh and M Staunton, 2002, *Triumph of the Optimists: 101 Years of Global Investment Returns,* Princeton University Press, NJ; Dimson, E.,, P Marsh and M Staunton, 2008, The Worldwide Equity Risk Premium: a smaller puzzle, Chapter 11 in the Handbook of the Equity Risk Premium, edited by R. Mehra, Elsevier.

[63] *Credit Suisse Global Investment Returns Sourcebook,* 2014, Credit Suisse/ London Business School. Summary data is accessible at the Credit Suisse website.

Italy	5.7%	9.6%	3.0%	31.7%	3.4%	6.8%	2.8%	29.5%
Japan	6.1%	9.3%	2.6%	27.8%	5.1%	9.2%	3.1%	32.7%
Netherlands	4.3%	6.5%	2.1%	22.6%	3.4%	5.7%	2.1%	22.3%
New Zealand	4.3%	5.9%	1.7%	18.2%	3.9%	5.5%	1.7%	18.0%
Norway	3.1%	5.9%	2.5%	26.2%	2.4%	5.4%	2.6%	27.8%
South Africa	6.3%	8.4%	2.0%	21.8%	5.4%	7.2%	1.8%	19.6%
Spain	3.3%	5.5%	2.0%	21.7%	2.2%	4.2%	1.9%	20.8%
Sweden	3.8%	5.9%	1.9%	20.6%	3.1%	5.4%	2.0%	21.5%
Switzerland	3.6%	5.3%	1.9%	18.8%	2.1%	3.7%	1.6%	17.6%
U.K.	4.4%	6.1%	1.8%	19.7%	3.9%	5.2%	1.6%	17.2%
U.S.	5.5%	7.5%	1.8%	19.7%	4.5%	6.6%	1.9%	20.8%
Europe	3.5%	5.3%	1.8%	19.3%	3.3%	4.6%	1.5%	16.1%
World-ex U.S.	3.6%	5.3%	1.7%	18.7%	2.9%	4.0%	1.4%	14.7%
World	4.3%	5.7%	1.6%	17.0%	3.3%	4.6%	1.5%	15.5%

In making comparisons of the numbers in this table to prior years, note that this database was modified in two ways: the world estimates are now weighted by market capitalization and the issue of survivorship bias has been dealt with frontally by incorporating the return histories of three markets (Austria, China and Russia) where equity investors would have lost their entire investment during the century. Note that the risk premiums, averaged across the markets, are lower than risk premiums in the United States. For instance, the geometric average risk premium for stocks over long-term government bonds, across the non-US markets, is only 2.9%, lower than the 4.5% for the US markets. The results are similar for the arithmetic average premium, with the average premium of 4.0% across non-US markets being lower than the 6.6% for the United States. In effect, the difference in returns captures the survivorship bias, implying that using historical risk premiums based only on US data will results in numbers that are too high for the future.

Note that the "noise" problem persists, even with averaging across 20 markets and over 112 years. The standard error in the global equity risk premium estimate is 1.4%-1.7%, suggesting that the range for the historical premium remains a large one. In an addendum, Dimson, Marsh and Staunton decompose the realized equity risk premium in each market into three components: the level of dividends, the growth in those dividends and the effects on stock price of a changing multiple for dividend (price to dividend ratio). For the United States, they attribute 1.63% of the overall premium of 5.53% (for stocks over treasury bills) to growth in real dividends and 0.54% to expansion in the price

to dividend ratio. Of the global premium of 4.09%, 0.57% can be attributed to growth in dividends and 0.49% to increases in the price to dividend ratio.

Historical Premium Plus

If we accept the proposition that historical risk premiums are the best way to estimate future risk premiums and also come to terms with the statistical reality that we need long time periods of history to get reliable estimates, we are trapped when it comes to estimating risk premiums in most emerging markets, where historical data is either non-existent or unreliable. Furthermore, the equity risk premium that we estimate becomes the risk premium that we use for all stocks within a market, no matter what their differences are on market capitalization and growth potential; in effect, we assume that the betas we use will capture differences in risk across companies.

In this section, we consider one way out of this box, where we begin with the US historical risk premium (4.62%) or the global premium from the DMS data (3.3%) as the base premium for a mature equity market and then build additional premiums for riskier markets or classes of stock. For the first part of this section, we stay within the US equity market and consider the practice of adjusting risk premiums for company-specific characteristics, with market capitalization being the most common example. In the second part, we extend the analysis to look at emerging markets in Asia, Latin American and Eastern Europe, and take a look at the practice of estimating country risk premiums that augment the US equity risk premium. Since many of these markets have significant exposures to political and economic risk, we consider two fundamental questions in this section. The first relates to whether there should be an additional risk premium when valuing equities in these markets, because of the country risk. As we will see, the answer will depend upon whether we think country risk is diversifiable or non-diversifiable, view markets to be open or segmented and whether we believe in a one-factor or a multi-factor model. The second question relates to estimating equity risk premiums for emerging markets. Depending upon our answer to the first question, we will consider several solutions.

Small cap and other risk premiums

In computing an equity risk premium to apply to all investments in the capital asset pricing model, we are essentially assuming that betas carry the weight of measuring the risk in individual firms or assets, with riskier investments having higher betas than safer investments. Studies of the efficacy of the capital asset pricing model over the last three decades have cast some doubt on whether this is a reasonable assumption, finding

that the model understates the expected returns of stocks with specific characteristics; small market cap companies and companies low price to book ratios, in particular, seem to earn much higher returns than predicted by the CAPM. It is to counter this finding that many practitioners add an additional premium to the required returns (and costs of equity) of smaller market cap companies.

The CAPM and Market Capitalization

In one of very first studies to highlight the failure of the traditional capital asset pricing model to explain returns at small market cap companies, Banz (1981) looked returns on stocks from 1936-1977 and concluded that investing in the smallest companies (the bottom 20% of NYSE firms in terms of capitalization) would have generated about 6% more, after adjusting for beta risk, than larger cap companies.[64] In the years since, there has been substantial research on both the origins and durability of the small cap premium, with mixed conclusions. First, there is evidence of a small firm premium in markets outside the United States as well. Studies find small cap premiums of about 7% from 1955 to 1984 in the United Kingdom,[65] 8.8% in France and 3% in Germany,[66] and a premium of 5.1% for Japanese stocks between 1971 and 1988.[67] Dimson, March and Staunton (2014), in their updated assessment of equity risk premiums in global markets, also compute small cap premiums in 23 markets over long time periods (which range from 113 years for some markets to less for others). Of the 23 markets, small cap stocks have not outperformed the rest of the market in only Norway and Finland; the small cap premium, over the long term, has been higher in developed markets than in emerging markets. Second, while the small cap premium has been persistent in US equity markets, it has also been volatile, with large cap stocks outperforming small cap stocks for extended periods. In figure 4, we look at the difference in returns between small cap (defined as bottom 10% of firms in terms of market capitalization) and all US stocks

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64 Banz, R., 1981, *The Relationship between Return and Market Value of Common Stocks*, Journal of Financial Economics, v9.

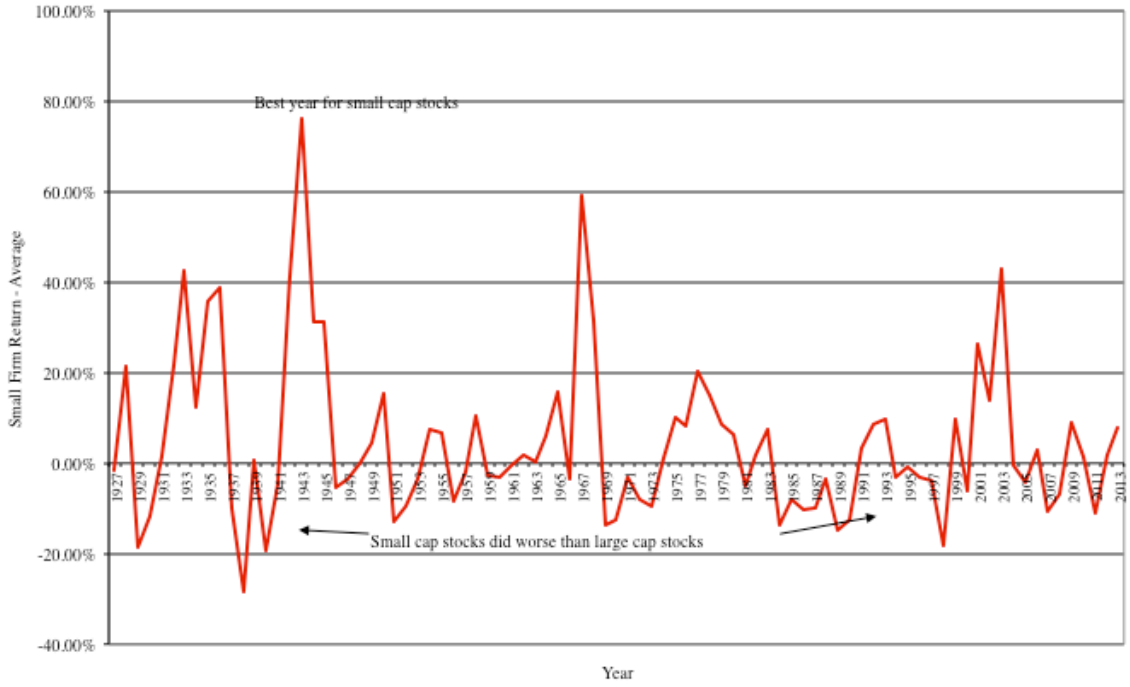
65 Dimson, E. and P.R. Marsh, 1986, *Event Studies and the Size Effect: The Case of UK Press Recommendations*, Journal of Financial Economics, v17, 113-142.

66 Bergstrom,G.L., R.D. Frashure and J.R. Chisholm, 1991, *The Gains from international small-company diversification* in Global Portfolios: Quantiative Strategies for Maximum Performance, Edited By R.Z. Aliber and B.R. Bruce, Business One Irwin, Homewood.

67 Chan, L.K., Y. Hamao, and J. Lakonishok, 1991, *Fundamentals and Stock Returns in Japan*, Journal of Finance. v46. 1739-1789.

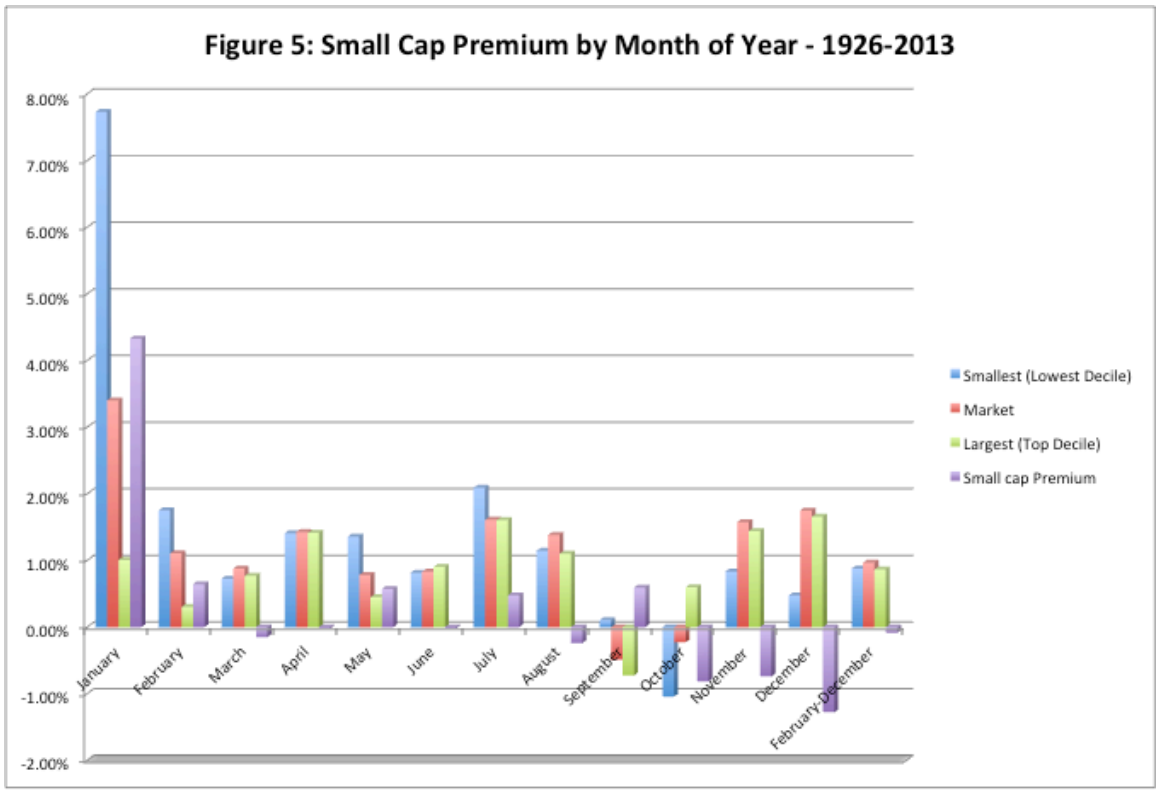
between 1927 and 2013; note that the premium was pronounced in the 1970s and disappeared for much of the 1980s.[68]

Figure 4: Small Firm Premium over time- 1927 -2013



The average premium for stocks in the smallest companies, in terms of market capitalization, between 1926 and 2013 was 4.45%, but the standard error in that estimate is 1.96%. Third, much of the premium is generated in one month of the year: January. As Figure 5 shows, eliminating that month from our calculations would essentially dissipate the entire small stock premium. That would suggest that size itself is not the source of risk, since small firms in January remain small firms in the rest of the year, but that the small firm premium, if it exists, comes from some other risk that is more pronounced or prevalent in January than in the rest of the year.

[68] The raw data for this table is obtained from Professor Ken French's website at Dartmouth. These premiums are based on value weighted portfolios. If equally weighted portfolios are used, the small cap premium is larger (almost 10.71%).



Source: Raw data from Ken French

Finally, a series of studies have argued that market capitalization, by itself, is not the reason for excess returns but that it is a proxy for other ignored risks such as illiquidity and poor information.

In summary, while the empirical evidence supports the notion that small cap stocks have earned higher returns after adjusting for beta risk than large cap stocks, it is not as conclusive, nor as clean as it was initially thought to be. The argument that there is, in fact, no small cap premium and that we have observed over time is just an artifact of history cannot be rejected out of hand.

The Small Cap Premium

If we accept the notion that there is a small cap premium, there are two ways in which we can respond to the empirical evidence that small market cap stocks seem to earn higher returns than predicted by the traditional capital asset pricing model. One is to view this as a market inefficiency that can be exploited for profit: this, in effect, would require us to load up our portfolios with small market cap stocks that would then proceed to deliver higher than expected returns over long periods. The other is to take the excess returns as evidence that betas are inadequate measures of risk and view the additional

returns are compensation for the missed risk. The fact that the small cap premium has endured for as long as it has suggests that the latter is the more reasonable path to take.

If CAPM betas understate the true risk of small cap stocks, what are the solutions? The first is to try and augment the model to reflect the missing risk, but this would require being explicit about this risk. For instance, there are models that include additional factors for illiquidity and imperfect information that claim to do better than the CAPM in predicting future returns. The second and simpler solution that is adopted by many practitioners is to add a premium to the expected return (from the CAPM) of small cap stocks. To arrive at this premium, analysts look at historical data on the returns on small cap stocks and the market, adjust for beta risk, and attribute the excess return to the small cap effect. As we noted earlier, using the data from 1926-2013, we would estimate a small cap premium of 4.45%. Duff and Phelps present a richer set of estimates, where the premiums are computed for stocks in 25 different size classes (with size measured on eight different dimensions including market capitalization, book value and net income). Using the Fama/French data, we present excess returns for firms broken down by ten market value classes in Table 7, with the standard error for each estimate.

Table 7: Excess Returns by Market Value Class: US Stocks from 1927 – 2013

Excess Return = Return on Portfolio – Return on Market

Decile	Average	Standard Error	Maximum	Minimum
Smallest	4.45%	1.96%	76.28%	-28.42%
2	1.71%	1.14%	41.25%	-17.96%
3	1.50%	0.77%	41.98%	-13.54%
4	0.68%	0.55%	15.56%	-7.33%
5	0.08%	0.53%	11.63%	-16.05%
6	0.00%	0.51%	15.21%	-14.01%
7	-0.50%	0.55%	7.48%	-19.50%
8	-1.60%	0.81%	11.20%	-29.42%
9	-2.24%	1.02%	21.96%	-36.09%
Largest	-4.09%	1.56%	31.29%	-65.57%

Note that the market capitalization effect shows up at both extremes – the smallest firms earn higher returns than expected whereas the largest firms earn lower returns than expected. The small firm premium is statistically significant only for the lowest and three highest size deciles.

Perils of the approach

While the small cap premium may seem like a reasonable way of dealing with the failure of the CAPM to capture the risk in smaller companies, there are significant costs to using the approach.

a. Standard Error on estimates: One of the dangers we noted with using historical risk premiums is the high standard error in our estimates. This danger is magnified when we look at sub-sets of stocks, based on market capitalization or any other characteristic, and extrapolate past returns. The standard errors on the small cap premiums that are estimated are likely to be significant, as is evidenced in table 7.
b. Small versus Large Cap: At least in its simplest form, the small cap premium adjustment requires us to divide companies into small market companies and the rest of the market, with stocks falling on one side of the line having much higher required returns (and costs of equity) than stocks falling on the other side.
c. Understanding Risk: Even in its more refined format, where the required returns are calibrated to market cap, using small cap premiums allows analysts to evade basic questions about what it is that makes smaller cap companies riskier, and whether these factors may vary across companies.
d. Small cap companies become large cap companies over time: When valuing companies, we attach high growth rates to revenues, earnings and value over time. Consequently, companies that are small market cap companies now grow to become large market cap companies over time. Consistency demands that we adjust the small cap premium as we go further into a forecast period.
e. Other risk premiums: Using a small cap premium opens the door to other premiums being used to augment expected returns. Thus, we could adjust expected returns upwards for stocks with price momentum and low price to book ratios, reflecting the excess returns that these characteristics seem to deliver, at least on paper. Doing so will deliver values that are closer to market prices, across assets, but undercuts the rationale for intrinsic valuation, i.e., finding market mistakes.

There is another reason why we are wary about adjusting costs of equity for a small cap effect. If, as is the practice now, we add a small cap premium of 4-5% to the cost of equity of small companies, without attributing this premium to any specific risk factor, we are exposed to the risk of double counting risk. For instance, assume that the small cap premium that we have observed over the last few decades is attributable to the lower

liquidity (and higher transactions costs) of trading small cap stocks. Adding that premium on to the discount rate will reduce the estimated values of small cap and private businesses. If we attach an illiquidity discount to this value, we are double counting the effect of illiquidity.

The small cap premium is firmly entrenched in practice, with analysts generally adding on 4-5% to the conventional cost of equity for small companies, with the definition of small shifting from analyst to analyst. Even if you believe that small cap companies are more exposed to market risk than large cap ones, this is an extremely sloppy and lazy way of dealing with that risk, since risk ultimately has to come from something fundamental (and size is not a fundamental factor). Thus, if you believe that small cap stocks are more prone to failure or distress, it behooves you to measure that risk directly and incorporate it into the cost of equity. If it is illiquidity that is at the heart of the small cap premium, then you should be measuring liquidity risk and incorporating it into the cost of equity and you certainly should not be double counting the risk by first incorporating a small cap premium into the discount rate and then applying an illiquidity discount to value.

Country Risk Premiums

As both companies and investors get used to the reality of a global economy, they have also been forced to confront the consequences of globalization for equity risk premiums and hurdle rates. Should an investor putting his money in Indian stocks demand a higher risk premium for investing in equities that one investing in German stocks? Should a US consumer product company investing in Brazil demand the same hurdle rates for its Brazilian investments as it does for its US investments? In effect, should we demand one global equity risk premium that we use for investments all over the world or should we use higher equity risk premiums in some markets than in others?

The arguments for no country risk premium

Is there more risk in investing in a Malaysian or Brazilian stock than there is in investing in the United States? The answer, to most, seems to be obviously affirmative, with the solution being that we should use higher equity risk premiums when investing in riskier emerging markets. There are, however, three distinct and different arguments offered against this practice.

1. Country risk is diversifiable

In the risk and return models that have developed from conventional portfolio theory, and in particular, the capital asset pricing model, the only risk that is relevant for

purposes of estimating a cost of equity is the market risk or risk that cannot be diversified away. The key question in relation to country risk then becomes whether the additional risk in an emerging market is diversifiable or non-diversifiable risk. If, in fact, the additional risk of investing in Malaysia or Brazil can be diversified away, then there should be no additional risk premium charged. If it cannot, then it makes sense to think about estimating a country risk premium.

But diversified away by whom? Equity in a publicly traded Brazilian, or Malaysian, firm can be held by hundreds or even thousands of investors, some of whom may hold only domestic stocks in their portfolio, whereas others may have more global exposure. For purposes of analyzing country risk, we look at the marginal investor – the investor most likely to be trading on the equity. If that marginal investor is globally diversified, there is at least the potential for global diversification. If the marginal investor does not have a global portfolio, the likelihood of diversifying away country risk declines substantially. Stulz (1999) made a similar point using different terminology.[69] He differentiated between segmented markets, where risk premiums can be different in each market, because investors cannot or will not invest outside their domestic markets, and open markets, where investors can invest across markets. In a segmented market, the marginal investor will be diversified only across investments in that market, whereas in an open market, the marginal investor has the opportunity (even if he or she does not take it) to invest across markets. It is unquestionable that investors today in most markets have more opportunities to diversify globally than they did three decades ago, with international mutual funds and exchange traded funds, and that many more of them take advantage of these opportunities. It is also true still that a significant home bias exists in most investors' portfolios, with most investors over investing in their home markets.

Even if the marginal investor is globally diversified, there is a second test that has to be met for country risk to be diversifiable. All or much of country risk should be country specific. In other words, there should be low correlation across markets. Only then will the risk be diversifiable in a globally diversified portfolio. If, on the other hand, the returns across countries have significant positive correlation, country risk has a market risk component, is not diversifiable and can command a premium. Whether returns across countries are positively correlated is an empirical question. Studies from the 1970s and 1980s suggested that the correlation was low, and this was an impetus for global diversification.[70] Partly because of the success of that sales pitch and partly

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[69] Stulz, R.M., *Globalization, Corporate finance, and the Cost of Capital,* Journal of Applied Corporate Finance, v12. 8-25.

[70] Levy, H. and M. Sarnat, 1970, *International Diversification of Investment Portfolios*, American

because economies around the world have become increasingly intertwined over the last decade, more recent studies indicate that the correlation across markets has risen. The correlation across equity markets has been studied extensively over the last two decades and while there are differences, the overall conclusions are as follows:

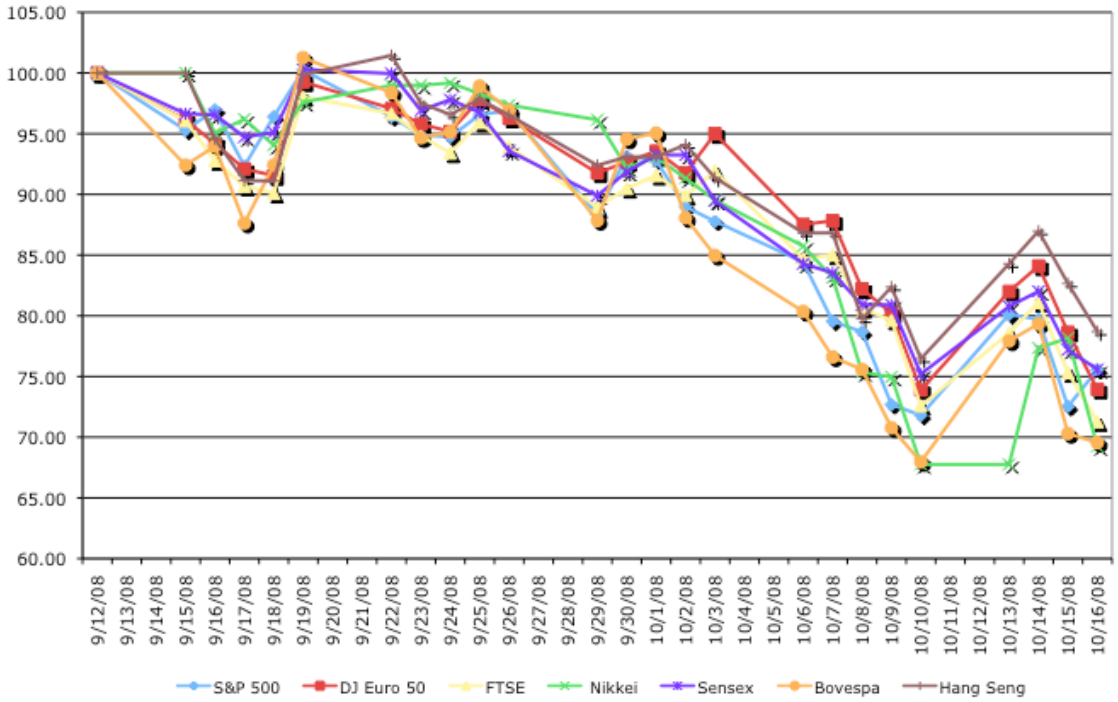
1. The correlation across markets has increased over time, as both investors and firms have globalized. Yang, Tapon and Sun (2006) report correlations across eight, mostly developed markets between 1988 and 2002 and note that the correlation in the 1998-2002 time period was higher than the correlation between 1988 and 1992 in every single market; to illustrate, the correlation between the Hong Kong and US markets increased from 0.48 to 0.65 and the correlation between the UK and the US markets increased from 0.63 to 0.82.[71] In the global returns sourcebook, from Credit Suisse, referenced earlier for historical risk premiums for different markets, the authors estimate the correlation between developed and emerging markets between 1980 and 2013, and note that it has increased from 0.57 in 1980 to 0.88 in 2013.
2. The correlation across equity markets increases during periods of extreme stress or high volatility.[72] This is borne out by the speed with which troubles in one market, say Russia, can spread to a market with little or no obvious relationship to it, say Brazil. The contagion effect, where troubles in one market spread into others is one reason to be skeptical with arguments that companies that are in multiple emerging markets are protected because of their diversification benefits. In fact, the market crisis in the last quarter of 2008 illustrated how closely bound markets have become, as can be seen in figure 6:

Economic Review 60(4), 668-75.

[71] Yang, Li , Tapon, Francis and Sun, Yiguo, 2006, *International correlations across stock markets and industries: trends and patterns 1988-2002*, Applied Financial Economics, v16: 16, 1171-1183

[72] Ball, C. and W. Torous, 2000, *Stochastic correlation across international stock markets*, Journal of Empirical Finance. v7, 373-388.

Figure 6: The globalization of risk



Between September 12, 2008 and October 16, 2008, markets across the globe moved up and down together, with emerging markets showing slightly more volatility.

3. In a twist on the last point, Longin and Solnik (2001) report that it is not high volatility per se that increases correlation, but downside volatility. Put differently, the correlation between global equity markets is higher in bear markets than in bull markets.[73]

2. A Global Capital Asset Pricing Model

The other argument against adjusting for country risk comes from theorists and practitioners who believe that the traditional capital asset pricing model can be adapted fairly easily to a global market. In their view, all assets, no matter where they are traded, should face the same global equity risk premium, with differences in risk captured by differences in betas. In effect, they are arguing that if Malaysian stocks are riskier than US stocks, they should have higher betas and expected returns.

While the argument is reasonable, it flounders in practice, partly because betas do not seem capable of carry the weight of measuring country risk.

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[73] Longin, F. and B. Solnik, 2001, *Extreme Correlation of International Equity Markets*, Journal of Finance, v56 , pg 649-675.

1. If betas are estimated against local indices, as is usually the case, the average beta within each market (Brazil, Malaysia, US or Germany) has to be one. Thus, it would be mathematically impossible for betas to capture country risk.
2. If betas are estimated against a global equity index, such as the Morgan Stanley Capital Index (MSCI), there is a possibility that betas could capture country risk but there is little evidence that they do in practice. Since the global equity indices are market weighted, it is the companies that are in developed markets that have higher betas, whereas the companies in small, very risky emerging markets report low betas. Table 8 reports the average beta estimated for the ten largest market cap companies in Brazil, India, the United States and Japan against the MSCI.

Table 8: Betas against MSCI – Large Market Cap Companies

Country	*Average Beta (against local index)*	*Average Beta (against MSCI)*
India	0.97	0.83
Brazil	0.98	0.81
United States	0.96	1.05
Japan	0.94	1.03

[a] The betas were estimated using two years of weekly returns from January 2006 to December 2007 against the most widely used local index (Sensex in India, Bovespa in Brazil, S&P 500 in the US and the Nikkei in Japan) and the MSCI using two years of weekly returns.

The emerging market companies consistently have lower betas, when estimated against global equity indices, than developed market companies. Using these betas with a global equity risk premium will lead to lower costs of equity for emerging market companies than developed market companies. While there are creative fixes that practitioners have used to get around this problem, they seem to be based on little more than the desire to end up with higher expected returns for emerging market companies.[74]

3. Country risk is better reflected in the cash flows

The essence of this argument is that country risk and its consequences are better reflected in the cash flows than in the discount rate. Proponents of this point of view argue that bringing in the likelihood of negative events (political chaos, nationalization and economic meltdowns) into the expected cash flows effectively risk adjusts the cashflows, thus eliminating the need for adjusting the discount rate.

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[74] There are some practitioners who multiply the local market betas for individual companies by a beta for that market against the US. Thus, if the beta for an Indian chemical company is 0.9 and the beta for the Indian market against the US is 1.5, the global beta for the Indian company will be 1.35 (0.9*1.5). The beta for the Indian market is obtained by regressing returns, in US dollars, for the Indian market against returns on a US index (say, the S&P 500).

This argument is alluring but it is wrong. The expected cash flows, computed by taking into account the possibility of poor outcomes, is not risk adjusted. In fact, this is exactly how we should be calculating expected cash flows in any discounted cash flow analysis. Risk adjustment requires us to adjust the expected cash flow further for its risk, i.e. compute certainty equivalent cash flows in capital budgeting terms. To illustrate why, consider a simple example where a company is considering making the same type of investment in two countries. For simplicity, let us assume that the investment is expected to deliver $ 90, with certainty, in country 1 (a mature market); it is expected to generate $ 100 with 90% probability in country 2 (an emerging market) but there is a 10% chance that disaster will strike (and the cash flow will be $0). The expected cash flow is $90 on both investments, but only a risk neutral investor would be indifferent between the two. A risk averse investor would prefer the investment in the mature market over the emerging market investment, and would demand a premium for investing in the emerging market.

In effect, a full risk adjustment to the cash flows will require us to go through the same process that we have to use to adjust discount rates for risk. We will have to estimate a country risk premium, and use that risk premium to compute certainty equivalent cash flows.[75]

The arguments for a country risk premium

There are elements in each of the arguments in the previous section that are persuasive but none of them is persuasive enough.

- Investors have become more globally diversified over the last three decades and portions of country risk can therefore be diversified away in their portfolios. However, the significant home bias that remains in investor portfolios exposes investors disproportionately to home country risk, and the increase in correlation across markets has made a portion of country risk into non-diversifiable or market risk.
- As stocks are traded in multiple markets and in many currencies, it is becoming more feasible to estimate meaningful global betas, but it also is still true that these betas cannot carry the burden of capturing country risk in addition to all other macro risk exposures.
- Finally, there are certain types of country risk that are better embedded in the cash flows than in the risk premium or discount rates. In particular, risks that are

[75] In the simple example above, this is how it would work. Assume that we compute a country risk premium of 3% for the emerging market to reflect the risk of disaster. The certainty equivalent cash flow on the investment in that country would be $90/1.03 = $87.38.

discrete and isolated to individual countries should be incorporated into probabilities and expected cash flows; good examples would be risks associated with nationalization or related to acts of God (hurricanes, earthquakes etc.).

After you have diversified away the portion of country risk that you can, estimated a meaningful global beta and incorporated discrete risks into the expected cash flows, you will still be faced with residual country risk that has only one place to go: the equity risk premium.

There is evidence to support the proposition that you should incorporate additional country risk into equity risk premium estimates in riskier markets:

1. Historical equity risk premiums: Donadelli and Prosperi (2011) look at historical risk premiums in 32 different countries (13 developed and 19 emerging markets) and conclude that emerging market companies had both higher average returns and more volatility in these returns between 1988 and 2010 (see table 9)

Table 9: Historical Equity Risk Premiums (Monthly) by Region

Region	*Monthly ERP*	*Standard deviation*
Developed Markets	0.62%	4.91%
Asia	0.97%	7.56%
Latin America	2.07%	8.18%
Eastern Europe	2.40%	15.66%
Africa	1.41%	6.03%

While we remain cautious about using historical risk premiums over short time periods (and 22 years is short in terms of stock market history), the evidence is consistent with the argument that country risk should be incorporated into a larger equity risk premium.[76]

2. Survey premiums: Earlier in the paper, we referenced a paper by Fernandez et al (2013) that surveyed academics, analysts and companies in 82 countries on equity risk premiums. The reported average premiums vary widely across markets and are higher for riskier emerging markets, as can be seen in table 10.

Table 10: Survey Estimates of Equity Risk Premium: By Region

Region	Number	Average ERP	Median ERP
Africa	9	8.62%	8.59%
Developed Markets	20	6.06%	6.01%
Eastern Europe	12	7.63%	7.96%
Emerging Asia	13	7.60%	7.42%

[76] Donadelli, M. and L. Prosperi, 2011, *The Equity Risk Premium: Empirical Evidence from Emerging Markets*, Working Paper, http://ssrn.com/abstract=1893378.

EU Troubled	5	7.16%	6.81%
Latin America	15	9.67%	9.49%
Middle East	8	8.43%	8.88%
Grand Total	**82**	**7.77%**	**7.76%**

Again, while this does not conclusively prove that country risk commands a premium, it does indicate that those who do valuations in these countries seem to act like it does.

Ultimately, the question of whether country risk matters and should affect the equity risk premium is an empirical one, not a theoretical one, and for the moment, at least, the evidence seems to suggest that you should incorporate country risk into your discount rates. This could change as we continue to move towards a global economy, with globally diversified investors and a global equity market, but we are not there yet.

Estimating a Country Risk Premium

If country risk is not diversifiable, either because the marginal investor is not globally diversified or because the risk is correlated across markets, we are then left with the task of measuring country risk and considering the consequences for equity risk premiums. In this section, we will consider three approaches that can be used to estimate country risk premiums, all of which build off the historical risk premiums estimated in the last section. To approach this estimation question, let us start with the basic proposition that the risk premium in any equity market can be written as:

> Equity Risk Premium = Base Premium for Mature Equity Market + Country Risk Premium

The country premium could reflect the extra risk in a specific market. This boils down our estimation to estimating two numbers – an equity risk premium for a mature equity market and the additional risk premium, if any, for country risk. To estimate a mature market equity risk premium, we can look at one of two numbers. The first is the historical risk premium that we estimated for the United States, which yielded 4.62% as the geometric average premium for stocks over treasury bonds from 1928 to 2013. If we do this, we are arguing that the US equity market is a mature market, and that there is sufficient historical data in the United States to make a reasonable estimate of the risk premium. The other is the average historical risk premium across 20 equity markets, approximately 3.3%, that was estimated by Dimson et al (see earlier reference), as a counter to the survivor bias that they saw in using the US risk premium. Consistency would then require us to use this as the equity risk premium, in every other equity market that we deem mature; the equity risk premium in January 2014 would be 4.62% in Germany, France and the UK, for instance. For markets that are not mature, however, we

need to measure country risk and convert the measure into a country risk premium, which will augment the mature market premium.

Measuring Country Risk

There are at least three measures of country risk that we can use. The first is the sovereign rating attached to a country by ratings agencies. The second is to subscribe to services that come up with broader measures of country risk that explicitly factor in the economic, political and legal risks in individual countries. The third is go with a market-based measure such as the volatility in the country's currency or markets.

i. Sovereign Ratings

One of the simplest and most accessible measures of country risk is the rating assigned to a country's debt by a ratings agency (S&P, Moody's and Fitch, among others, all provide country ratings). These ratings measure default risk (rather than equity risk) but they are affected by many of the factors that drive equity risk – the stability of a country's currency, its budget and trade balances and political uncertainty, among other variables[77].

To get a measure of country ratings, consider six countries – Germany, Brazil, China, India, Russia and Greece. In January 2014, the Moody's ratings for the countries are summarized in table 11:

Table 11: Sovereign Ratings in January 2014 – Moody's

Country	*Foreign Currency Rating*	*Local Currency Rating*
Brazil	Baa2	Baa2
China	Aa3	Aa3
Germany	Aaa	Aaa
Greece	Caa3	Caa3
India	Baa3	Baa3
Russia	Baa1	Baa1

What do these ratings tell us? First, the local currency and foreign currency ratings are identical for all of the countries on the list. There are a few countries (not on this list) where the two ratings diverge, and when they do, the local currency ratings tend to be higher (or at worst equal to) the foreign currency ratings for most countries, because a country should be in a better position to pay off debt in the local currency than in a foreign currency. Second, at least based on Moody's assessments in 2014, Germany is the

[77] The process by which country ratings are obtained in explained on the S&P web site at http://www.ratings.standardpoor.com/criteria/index.htm.

safest company in this group, followed by China, Russia, Brazil, India and Greece, in that order. Third, ratings do change over time. In fact, Brazil's rating has risen from B1 in 2001 to its current rating of Baa2, reflecting both strong economic growth and a more robust political system. Appendix 2 contains the current ratings – local currency and foreign currency – for the countries that are tracked by Moody's in January 2014.[78]

While ratings provide a convenient measure of country risk, there are costs associated with using them as the only measure. First, ratings agencies often lag markets when it comes to responding to changes in the underlying default risk. The ratings for India, according to Moody's, were unchanged from 2004 to 2007, though the Indian economy grew at double-digit rates over that period. Similarly, Greece's ratings did not plummet until the middle of 2011, though their financial problems were visible well before that time. Second, the ratings agency focus on default risk may obscure other risks that could still affect equity markets. For instance, rising commodity (and especially oil) prices pushed up the ratings for commodity supplying countries (like Russia), even though there was little improvement in the rest of the economy. Finally, not all countries have ratings; much of sub-Saharan Africa, for instance, is unrated.

ii. Country Risk Scores

Rather than focus on just default risk, as rating agencies do, some services have developed numerical country risk scores that take a more comprehensive view of risk. These risk scores are often estimated from the bottom-up by looking at economic fundamentals in each country. This, of course, requires significantly more information and, as a consequence, most of these scores are available only to commercial subscribers.

The Political Risk Services (PRS) group, for instance, considers political, financial and economic risk indicators to come up with a composite measure of risk (ICRG) for each country that ranks from 0 to 100, with 0 being highest risk and 100 being the lowest risk.[79] Appendix 3 classifies countries based on composite country risk measures from the PRS Group in January 2014.[80] Harvey (2005) examined the efficacy

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[78] In a disquieting reaction to the turmoil of the market crisis in the last quarter of 2008, Moody's promoted the notion that Aaa countries were not all created equal and slotted these countries into three groups – resistant Aaa (the stongest), resilient Aaa (weaker but will probably survive intact) and vulnerable Aaa (likely to face additional default risk.

[79] The PRS group considers three types of risk – political risk, which accounts for 50% of the index, financial risk, which accounts for 25%, and economic risk, which accounts for the balance. While this table is dated, updated numbers are available for a hefty price. We have used the latest information in the public domain. Some university libraries have access to the updated data. While we have not updated the numbers, out of concerns about publishing proprietary data, you can get the latest PRS numbers by paying $99 on their website (http://www.prsgroup.com).

[80] Harvey, C.R., *Country Risk Components, the Cost of Capital, and Returns in Emerging Markets*,

of these scores and found that they were correlated with costs of capital, but only for emerging market companies.

The Economist, the business newsmagazine, also operates a country risk assessment unit that measures risk from 0 to 100, with 0 being the least risk and 100 being the most risk. In September 2008, Table 12 the following countries were ranked as least and most risky by their measure:

Table 12: Country Risk Scores – The Economist

Economist.com rankings

Country risk

Selected countries and territories, September 2008 (except where noted)

Least risky			Most risky		
Rank		Score*	Rank		Score
1	Switzerland †	12	120	Zimbabwe	86
2	Finland **	14	119	Iraq	80
	Norway **	14	118	Sudan	76
	Sweden ††	14	117	Myanmar	75
5	Canada **	17	116	Nicaragua	69
	Denmark †	17	115	Jamaica	68
	Netherlands §	17	114	Kenya	66
8	Germany ††	18	113	Cuba	64
9	Austria **	19	112	Cambodia	62
	France ††	19	111	Côte d'Ivoire	61
11	Belgium ††	20		Ecuador	61
12	Singapore	21		Pakistan	61
13	Japan **	23		Venezuela	61
14	Ireland #	24		Vietnam	61
	Britain	24	106	Syria	60
	United States †	24			

*Out of 100, with higher numbers indicating more risk. Scores are based on indicators from three categories: currency risk, sovereign debt risk and banking risk.

† May 2008; ** July 2008; †† June 2008; § August 2008; # February 2008

In fact, comparing the PRS and Economist measures of country risk provides some insight into the problems with using their risk measures. The first is that the measures may be internally consistent but are not easily comparable across different services. The Economist, for instance, assigns its lowest scores to the safest countries whereas PRS assigns the highest scores to these countries. The second is that, by their very nature, a significant component of these measures have to be black boxes to prevent others from

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Working paper, Duke University. Available at http://papers.ssrn.com/sol3/papers.cfm?abstract_id=620710.

replicating them at no cost. Third, the measures are not linear and the services do not claim that they are; a country with a risk score of 60 in the Economist measure is not twice as risky as a country with a risk score of 30.

iii. Market-based Measures

To those analysts who feel that ratings agencies are either slow to respond to changes in country risk or take too narrow a view of risk, there is always the alternative of using market based measures.

- Bond default spread: We can compute a default spread for a country if it has bonds that are denominated in currencies such as the US dollar, Euro or Yen, where there is a riskfree rate to compare it to. In January 2014, for instance, a 10-year US dollar denominated bond issued by the Brazilian government had a yield to maturity of 4.50%, giving it a default spread of 1.46% over the 10-year US treasury bond rate (3.04%), as of the same time.
- Credit Default Swap Spreads: In the last few years, credit default swaps (CDS) markets have developed, allowing us to obtain updated market measures of default risk in different entities. In particular, there are CDS spreads for countries (governments) that yield measures of default risk that are more updated and precise, at least in some cases, than bond default spreads.[81] Table 13 summarizes the CDS spreads for all countries where a CDS spread was available, in January 2014:

Table 13: Credit Default Swap Spreads (in basis points)– January 2014

Country	*10-year CDS*	*Net of US CDS*		*10-year CDS*	*Net of US CDS*
Abu Dhabi	1.00%	0.54%	Lithuania	1.77%	1.31%
Argentina	14.73%	14.27%	Malaysia	1.65%	1.19%
Australia	0.70%	0.24%	Mexico	1.49%	1.03%
Austria	0.74%	0.28%	Morocco	2.54%	2.08%
Bahrain	2.97%	2.51%	Netherlands	0.74%	0.28%
Belgium	0.97%	0.51%	New Zealand	0.80%	0.34%
Brazil	2.53%	2.07%	Norway	0.29%	-0.17%
Bulgaria	1.89%	1.43%	Panama	1.64%	1.18%
Chile	1.08%	0.62%	Peru	1.88%	1.42%
China	1.33%	0.87%	Philippines	1.81%	1.35%
Colombia	1.74%	1.28%	Poland	1.28%	0.82%
Costa Rica	3.43%	2.97%	Portugal	4.03%	3.57%
Croatia	3.97%	3.51%	Qatar	1.03%	0.57%
Czech Republic	1.07%	0.61%	Romania	2.61%	2.15%

[81] The spreads are usually stated in US dollar or Euro terms.

Denmark	0.54%	0.08%	Russia	2.21%	1.75%
Estonia	0.89%	0.43%	Saudi Arabia	1.09%	0.63%
Finland	0.48%	0.02%	Senegal	0.90%	0.44%
France	1.06%	0.60%	Slovakia	1.30%	0.84%
Germany	0.56%	0.10%	Slovenia	2.75%	2.29%
Hong Kong	0.91%	0.45%	South Africa	2.75%	2.29%
Hungary	3.08%	2.62%	Spain	1.96%	1.50%
Iceland	2.19%	1.73%	Sweden	0.39%	-0.07%
India	3.51%	3.05%	Switzerland	0.56%	0.10%
Indonesia	3.19%	2.73%	Thailand	1.86%	1.40%
Ireland	1.69%	1.23%	Tunisia	4.57%	4.11%
Israel	1.53%	1.07%	Turkey	2.89%	2.43%
Italy	2.11%	1.65%	United Arab Emirates	2.88%	2.42%
Japan	0.79%	0.33%	United Kingdom	0.57%	0.11%
Kazakhstan	2.26%	1.80%	United States of America	0.46%	0.00%
Korea	0.97%	0.51%	Venezuela	10.80%	10.34%
Latvia	1.69%	1.23%	Vietnam	3.35%	2.89%
Lebanon	4.38%	3.92%			

Source: Bloomberg
Spreads are for 10-year US $ CDS.

In January 2014, for instance, the CDS market yielded a spread of 2.53% for the Brazilian Government, higher than the 1.46% that we obtained from the 10-year dollar denominated Brazilian bond. However, the CDS market does have some counterparty risk exposure and other risk exposures that are incorporated into the spreads. In fact, there is no country with a zero CDS spread, indicating either that there is no entity with default risk or that the CDS spread is not a pure default spread. To counter that problem, we netted the US CDS spread of 0.46% from each country's CDS to get a modified measure of country default risk.[82] Using this approach for Brazil, for instance, yields a netted CDS spread of 2.07% for the country.

- Market volatility: In portfolio theory, the standard deviation in returns is generally used as the proxy for risk. Extending that measure to emerging markets, there are some analysts who argue that the best measure of country risk is the volatility in local stock prices. Stock prices in emerging markets will be more volatile that stock prices in developed markets, and the volatility measure should be a good indicator of country risk. While the argument makes intuitive sense, the practical problem with

[82] If we assume that there is default risk in the US, we would subtract the default spread associated with this risk from the 0.67% first, before netting the value against other CDS spreads. Thus, if the default spread for the US is 0.15%, we would subtract out only 0.52% (0.67% - 0.15%) from each country's CDS spread to get to a corrected default spread for that country.

using market volatility as a measure of risk is that it is as much a function of the underlying risk as it is a function of liquidity. Markets that are risky and illiquid often have low volatility, since you need trading to move stock prices. Consequently, using volatility measures will understate the risk of emerging markets that are illiquid and overstate the risk of liquid markets.

Market-based numbers have the benefit of constant updating and reflect the points of view of investors at any point in time. However, they also are also afflicted with all of the problems that people associate with markets – volatility, mood shifts and at times, irrationality. They tend to move far more than the other two measures – sovereign ratings and country risk scores – sometimes for good reasons and sometimes for no reason at all.

b. Estimating Country Risk Premium

How do we link a country risk measure to a country risk premium? In this section, we will look at three approaches. The first uses default spreads, based upon country bonds or ratings, whereas the latter two use equity market volatility as an input in estimating country risk premiums.

1. Default Spreads

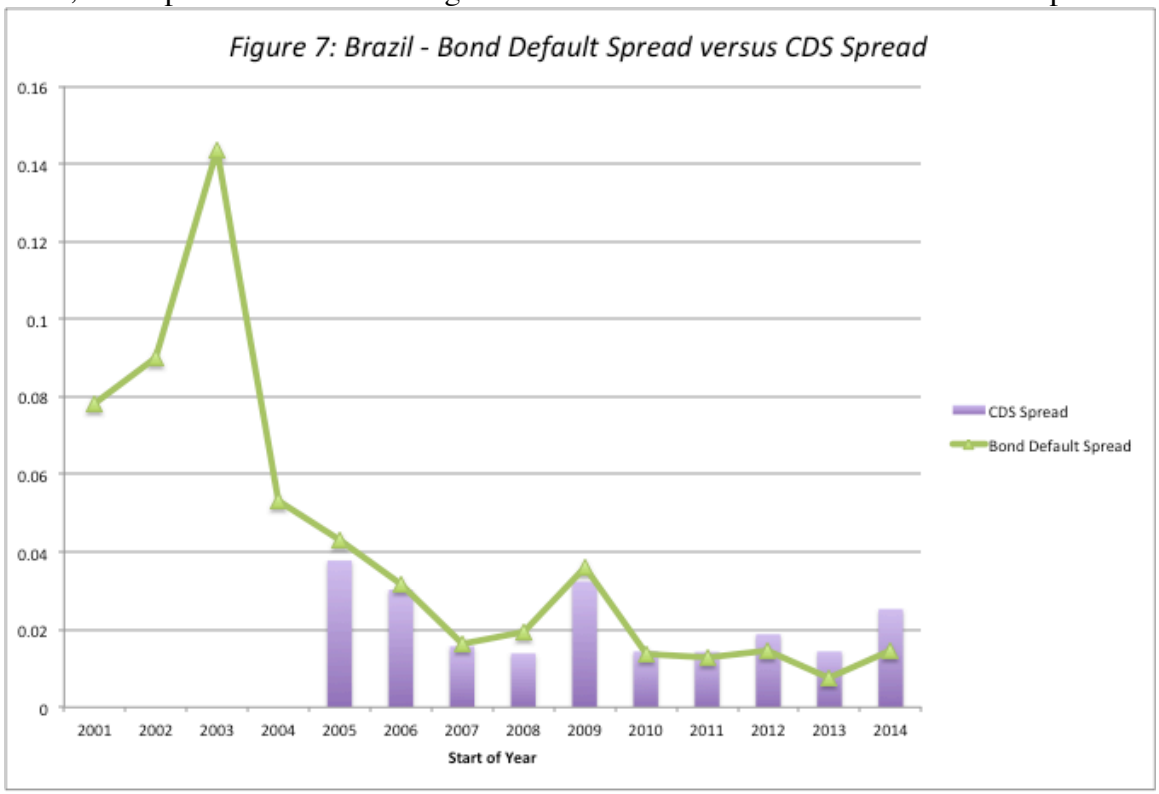
The simplest and most widely used proxy for the country risk premium is the default spread that investors charge for buying bonds issued by the country. This default spread can be estimated in one of three ways.

a. Current Default Spread on Sovereign Bond or CDS market: As we noted in the last section, the default spread comes from either looking at the yields on bonds issued by the country in a currency where there is a default free bond yield to which it can be compared or spreads in the CDS market.[83] With the 10-year US dollar denominated Brazilian bond that we cited as an example in the last section, the default spread would have amounted to 1.46% in January 2014: the difference between the interest rate on the Brazilian bond and a treasury bond of the same maturity. The netted CDS market spread on the same day for the default spread was 2.07%.

b. Average (Normalized) spread on bond: While we can make the argument that the default spread in the dollar denominated is a reasonable measure of the default risk in Brazil, it is also a volatile measure. In figure 7, we have graphed the yields on the dollar denominated ten-year Brazilian Bond and the U.S. ten-year treasury bond and highlighted the default spread (as the difference between the two yields) from January 2000 to

[83] You cannot compare interest rates across bonds in different currencies. The interest rate on a peso bond cannot be compared to the interest rate on a dollar denominated bond.

January 2014. In the same figure, we also show the 10-year CDS spreads from 2005 to 2014,[84] the spreads have also changed over time but move with the bond default spreads.



Note that the bond default spread widened dramatically during 2002, mostly as a result of uncertainty in neighboring Argentina and concerns about the Brazilian presidential elections.[85] After the elections, the spreads decreased just as quickly and continued on a downward trend through the middle of last year. Since 2004, they have stabilized, with a downward trend; they spiked during the market crisis in the last quarter of 2008 but have settled back into pre-crisis levels. Given this volatility, a reasonable argument can be made that we should consider the average spread over a period of time rather than the default spread at the moment. If we accept this argument, the normalized default spread, using the average spreads over the last 5 years of data would be 1.65% (bond default spread) or 1.99% (CDS spread). Using this approach makes sense only if the economic fundamentals of the country have not changed significantly (for the better or worse) during the period but will yield misleading values, if there have been structural shifts in the economy. In 2008, for instance, it would have made sense to use averages over time for a country like Nigeria, where oil price movements created volatility in spreads over

[84] Data for the sovereign CDS market is available only from the last part of 2004.

[85] The polls throughout 2002 suggested that Lula who was perceived by the market to be a leftist would beat the establishment candidate. Concerns about how he would govern roiled markets and any poll that showed him gaining would be followed by an increase in the default spread.

time, but not for countries like China and India, which saw their economies expand and mature dramatically over the period or Venezuela, where government capriciousness made operating private businesses a hazardous activity (with a concurrent tripling in default spreads).

c. Imputed or Synthetic Spread: The two approaches outlined above for estimating the default spread can be used only if the country being analyzed has bonds denominated in US dollars, Euros or another currency that has a default free rate that is easily accessible. Most emerging market countries, though, do not have government bonds denominated in another currency and some do not have a sovereign rating. For the first group (that have sovereign rating but no foreign currency government bonds), there are two solutions. If we assume that countries with the similar default risk should have the same sovereign rating, we can use the typical default spread for other countries that have the same rating as the country we are analyzing and dollar denominated or Euro denominated bonds outstanding. Thus, Bulgaria, with a Baa2 rating, would be assigned the same default spread as Brazil, which also has Baa2 rating, and dollar denominated bonds and CDS prices from which we can extract a default spread. For the second group, we are on even more tenuous grounds. Assuming that there is a country risk score from the Economist or PRS for the country, we could look for other countries that are rated and have similar scores and assign the default spreads that these countries face. For instance, we could assume that Cuba and Cameroon, which fall within the same score grouping from PRS, have similar country risk; this would lead us to attach Cuba's rating of Caa1 to Cameroon (which is not rated) and to use the same default spread (based on this rating) for both countries.

In table 12, we have estimated the typical default spreads for bonds in different sovereign ratings classes in January 2014. One problem that we had in obtaining the numbers for this table is that relatively few emerging markets have dollar or Euro denominated bonds outstanding. Consequently, there were some ratings classes where there was only one country with data and several ratings classes where there were none. To mitigate this problem, we used spreads from the CDS market, referenced in the earlier section. We were able to get default spreads for 63 countries, categorized by rating class, and we averaged the spreads across multiple countries in the same ratings class.[86] An alternative approach to estimating default spread is to assume that sovereign ratings are comparable to corporate ratings, i.e., a Ba1 rated country bond and a Ba1 rated corporate

[86] There were seven Baa2 rated countries, with ten-year CDS spreads, in January 2013. The average spread across the these countries is 1.83%.

bond have equal default risk. In this case, we can use the default spreads on corporate bonds for different ratings classes. Table 14 summarizes the typical default spreads by sovereign rating class in January 2014, and compares it to the default spreads for similar corporate ratings.

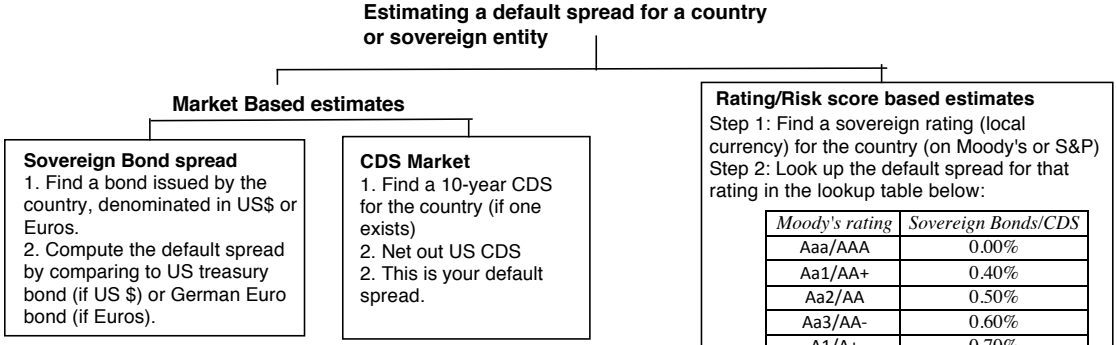
Table 14: Default Spreads by Ratings Class – Sovereign vs. Corporate in January 2014

Moody's rating	*Sovereign Bonds/CDS*	Corporate Bonds
Aaa/AAA	0.00%	0.42%
Aa1/AA+	0.40%	0.57%
Aa2/AA	0.50%	0.71%
Aa3/AA-	0.60%	0.75%
A1/A+	0.70%	0.78%
A2/A	0.85%	0.84%
A3/A-	1.20%	1.00%
Baa1/BBB+	1.60%	1.32%
Baa2/BBB	1.90%	1.52%
Baa3/BBB-	2.20%	1.78%
Ba1/BB+	2.50%	2.59%
Ba2/BB	3.00%	3.39%
Ba3/BB-	3.60%	4.20%
B1/B+	4.50%	5.01%
B2/B	5.50%	5.81%
B3/B-	6.50%	6.62%
Caa1/ CCC+	7.50%	7.43%
Caa2/CCC	9.00%	8.75%
Caa3/ CCC-	10.00%	10.00%

Note that the corporate bond spreads, at least in January 2014, were slightly larger than the sovereign spreads for the higher ratings classes, converge for the intermediate ratings and widen again at the lowest ratings. Using this approach to estimate default spreads for Brazil, with its rating of Baa2 would result in a spread of 1.90% (1.52%), if we use sovereign spreads (corporate spreads). These spreads are down from post-crisis levels at the end of 2008 but are still larger than the actual spreads on Brazilian sovereign bonds in early 2014.

Figure 8 depicts the alternative approaches to estimating default spreads for four countries, Brazil, China, India and Poland, in early 2014:

Figure 8: Approaches for estimating Sovereign Default Spreads



Country	Sovereign Bond Yield	Currency	Risk free rate	Default Spread	CDS Spread (net of US)
Brazil	4.50%	US$	3.04%	1.46%	2.07%
China	NA	NA	NA	NA	0.87%
India	NA	NA	NA	NA	3.05%
Poland	2.50%	Euro	1.80%	0.70%	0.82%

Moody's rating	Sovereign Bonds/CDS
Aaa/AAA	0.00%
Aa1/AA+	0.40%
Aa2/AA	0.50%
Aa3/AA-	0.60%
A1/A+	0.70%
A2/A	0.85%
A3/A-	1.20%
Baa1/BBB+	1.60%
Baa2/BBB	1.90%
Baa3/BBB-	2.20%
Ba1/BB+	2.50%
Ba2/BB	3.00%
Ba3/BB-	3.60%
B1/B+	4.50%
B2/B	5.50%
B3/B-	6.50%
Caa1/ CCC+	7.50%
Caa2/CCC	9.00%
Caa3/ CCC-	10.00%

Country	Moody's Rating	Default Spread
Brazil	Baa2	1.90%
China	Aa3	0.60%
India	Baa3	2.20%
Poland	A2	0.85%

With some countries, without US-dollar (or Euro) denominated sovereign bonds or CDS spreads, you don't have a choice since the only estimate of the default spread comes from the sovereign rating. With other countries, such as Brazil, you have multiple estimates of the default spreads: 1.46% from the dollar denominated bond, 2.53% from the CDS spread, 2.07% from the netted CDS spread and 1.90% from the sovereign rating look up table. You could choose one of these approaches and stay consistent over time or average across them.

Analysts who use default spreads as measures of country risk typically add them on to both the cost of equity and debt of every company traded in that country. Thus, the cost of equity for an Indian company, estimated in U.S. dollars, will be 2.2% higher than the cost of equity of an otherwise similar U.S. company, using the January 2014 measure of the default spread, based upon the rating. In some cases, analysts add the default spread to the U.S. risk premium and multiply it by the beta. This increases the cost of equity for high beta companies and lowers them for low beta firms.[87]

[87] In a companion paper, I argue for a separate measure of company exposure to country risk called lambda that is scaled around one (just like beta) that is multiplied by the country risk premium to estimate the cost of equity. See Damodaran, A., 2007, Measuring Company Risk Exposure to Country Risk, Working Paper, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=889388.

While many analysts use default spreads as proxies for country risk, the evidence for its use is still thin. Abuaf (2011) examines ADRs from ten emerging markets and relates the returns on these ADRs to returns on the S&P 500 (which yields a conventional beta) and to the CDS spreads for the countries of incorporation. He finds that ADR returns as well as multiples (such as PE ratios) are correlated with movement in the CDS spreads over time and argues for the addition of the CDS spread (or some multiple of it) to the costs of equity and capital to incorporate country risk.[88]

2. Relative Equity Market Standard Deviations

There are some analysts who believe that the equity risk premiums of markets should reflect the differences in equity risk, as measured by the volatilities of these markets. A conventional measure of equity risk is the standard deviation in stock prices; higher standard deviations are generally associated with more risk. If you scale the standard deviation of one market against another, you obtain a measure of relative risk. For instance, the relative standard deviation for country X (against the US) would be computed as follows:

$$\text{Relative Standard Deviation}_{\text{Country X}} = \frac{\text{Standard Deviation}_{\text{Country X}}}{\text{Standard Deviation}_{\text{US}}}$$

If we assume a linear relationship between equity risk premiums and equity market standard deviations, and we assume that the risk premium for the US can be computed (using historical data, for instance) the equity risk premium for country X follows:

$$\text{Equity risk premium}_{\text{Country X}} = \text{Risk Premum}_{\text{US}} * \text{Relative Standard Deviation}_{\text{Country X}}$$

Assume, for the moment, that you are using an equity risk premium for the United States of 5.00%. The annualized standard deviation in the S&P 500 in two years preceding January 2014, using weekly returns, was 11.12%, whereas the standard deviation in the Bovespa (the Brazilian equity index) over the same period was 18.65%.[89] Using these values, the estimate of a total risk premium for Brazil would be as follows.

$$\text{Equity Risk Premium}_{Brazil} = 5.00\% * \frac{18.65\%}{11.12\%} = 8.39\%$$

The country risk premium for Brazil can be isolated as follows:

$$\text{Country Risk Premium}_{Brazil} = 8.39\% - 5.00\% = 3.39\%$$

Table 15 lists country volatility numbers for some of the Latin American markets and the resulting total and country risk premiums for these markets, based on the assumption that

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[88] Abuaf, N., 2011, *Valuing Emerging Market Equities – The Empirical Evidence*, Journal of Applied Finance, v21, 123-138.

[89] If the dependence on historical volatility is troubling, the options market can be used to get implied volatilities for both the US market (18.03%) and for the Bovespa (23.56%).

the equity risk premium for the United States is 5.0%. Appendix 4 contains a more complete list of emerging markets, with equity risk premiums and country risk premiums estimated for each.

Table 15: Equity Market Volatilities and Risk Premiums (Weekly returns: Feb 12-Feb 14): Latin American Countries

Country	*Standard deviation in Equities (weekly)*	*Relative Volatility (to US)*	*Total Equity Risk Premium*	*Country risk premium*
Argentina	29.64%	2.67	13.33%	8.33%
Brazil	18.65%	1.68	8.39%	3.39%
Chile	13.50%	1.21	6.07%	1.07%
Colombia	12.00%	1.08	5.40%	0.40%
Costa Rica	8.23%	0.74	3.70%	-1.30%
Mexico	14.01%	1.26	6.30%	1.30%
Panama	6.29%	0.57	2.83%	-2.17%
Peru	16.63%	1.50	7.48%	2.48%
US	**11.12%**	**1.00**	**5.00%**	**0.00%**
Venezuela	40.03%	3.60	18.00%	13.00%

While this approach has intuitive appeal, there are problems with using standard deviations computed in markets with widely different market structures and liquidity. Since equity market volatility is affected by liquidity, with more liquid markets often showing higher volatility, this approach will understate premiums for illiquid markets and overstate the premiums for liquid markets. For instance, the standard deviations for Panama and Costa Rica are lower than the standard deviation in the S&P 500, leading to equity risk premiums for those countries that are lower than the US. The second problem is related to currencies since the standard deviations are usually measured in local currency terms; the standard deviation in the U.S. market is a dollar standard deviation, whereas the standard deviation in the Brazilian market is based on nominal Brazilian Real returns. This is a relatively simple problem to fix, though, since the standard deviations can be measured in the same currency – you could estimate the standard deviation in dollar returns for the Brazilian market.

3. Default Spreads + Relative Standard Deviations

In the first approach to computing equity risk premiums, we assumed that the default spreads (actual or implied) for the country were good measures of the additional risk we face when investing in equity in that country. In the second approach, we argued that the information in equity market volatility can be used to compute the country risk

premium. In the third approach, we will meld the first two, and try to use the information in both the country default spread and the equity market volatility.

The country default spreads provide an important first step in measuring country equity risk, but still only measure the premium for default risk. Intuitively, we would expect the country equity risk premium to be larger than the country default risk spread. To address the issue of how much higher, we look at the volatility of the equity market in a country relative to the volatility of the bond market used to estimate the spread. This yields the following estimate for the country equity risk premium.

$$\text{Country Risk Premium} = \text{Country Default Spread} * \left(\frac{\sigma_{\text{Equity}}}{\sigma_{\text{Country Bond}}} \right)$$

To illustrate, consider again the case of Brazil. As noted earlier, the default spread for Brazil in January 2014, based upon its sovereign rating, was 1.90%. We computed annualized standard deviations, using two years of weekly returns, in both the equity market and the government bond, in early March 2014. The annualized standard deviation in the Brazilian dollar denominated ten-year bond was 11.02%, well below the standard deviation in the Brazilian equity index of 18.65%. The resulting country equity risk premium for Brazil is as follows:

$$\text{Brazil Country Risk Premium} = 1.90\% * \frac{18.65\%}{11.02\%} = 3.22\%$$

Unlike the equity standard deviation approach, this premium is in addition to a mature market equity risk premium. Thus, assuming a 5% mature market premium, we would compute a total equity risk premium for Brazil of 8.22%:

Brazil's Total Equity Risk Premium = 5.0% + 3.22% = 8.22%

Note that this country risk premium will increase if the country rating drops or if the relative volatility of the equity market increases.

Why should equity risk premiums have any relationship to country bond spreads? A simple explanation is that an investor who can make 1.90% risk premium on a dollar-denominated Brazilian government bond would not settle for a risk premium of 1.90% (in dollar terms) on Brazilian equity. Playing devil's advocate, however, a critic could argue that the interest rate on a country bond, from which default spreads are extracted, is not really an expected return since it is based upon the promised cash flows (coupon and principal) on the bond rather than the expected cash flows. In fact, if we wanted to estimate a risk premium for bonds, we would need to estimate the expected return based upon expected cash flows, allowing for the default risk. This would result in a lower default spread and equity risk premium. Both this approach and the last one use the standard deviation in equity of a market to make a judgment about country risk premium,

but they measure it relative to different bases. This approach uses the country bond as a base, whereas the previous one uses the standard deviation in the U.S. market. This approach assumes that investors are more likely to choose between Brazilian bonds and Brazilian equity, whereas the previous approach assumes that the choice is across equity markets.

There are two potential measurement problems with using this approach. The first is that the relative standard deviation of equity is a volatile number, both across countries (ranging from 4.62 for Spain to 0.86 for Greece) and across time (Brazil's relative volatility numbers have ranged from close to one to well above 2). The second is that computing the relative volatility requires us to estimate volatility in the government bond, which, in turn, presupposes that long-term government bonds not only exist but are also traded.[90] In countries where this data item is not available, we have three choices. One is to fall back on one of the other two approaches. The second is to use a different market measure of default risk, say the CDS spread, and compute the standard deviation in the spread; this number can be standardized by dividing the level of the spread. The third is to compute a cross sectional average of the ratio of stock market to bond market volatility across countries, where both items are available, and use that average. In 2014, for instance, there were 27 emerging markets, where both the equity market volatility and the government bond volatility numbers were available, at least for 100 trading weeks; the numbers are summarized in Appendix 5. The median ratio, across these markets, of equity market volatility to bond price volatility was approximately 1.79.[91] We also computed two other measures of relative volatility: equity volatility divided by the coefficient of variation in the bond yield and equity volatility divided by the coefficient of variation in the CDS spread.

	$\sigma_{Equity} / \sigma_{Bond}$	$\sigma_{Equity} / \sigma_{Yield}$	$\sigma_{Equity} / \sigma_{CDS}$
Number of countries with data	32	32	46
Average	1.94	0.86	1.61
Median	1.79	0.75	1.09
Maximum	4.62	1.73	11.10
Minimum	0.86	0.44	0.51

[90] One indication that the government bond is not heavily traded is an abnormally low standard deviation on the bond yield.

[91] The ratio seems to be lowest in the markets with the highest default spreads and higher in markets with lower default spreads. The median ratio this year is higher than it has been historically. On my website, I continue to use a multiple of 1.50, reflecting the historical value for this ratio.

Looking at the descriptive statistics, the need to adjust default spreads seems to be smaller, at least in the cross section, if you use the CDS spread as your measure of the default spread for a country; the median ratio is close to one.

Choosing between the approaches

The three approaches to estimating country risk premiums will usually give you different estimates, with the bond default spread and relative equity standard deviation approaches generally yielding lower country risk premiums than the melded approach that uses both the country bond default spread and the equity and bond standard deviations. Table 16 summarizes the estimates of country equity and total risk premium using the three approaches for Brazil in March 2014:

Table 16: Country and Total Equity Risk Premium: Brazil in January 2013

Approach	*Mature Market Equity Premium*	*Brazil Country Risk Premium*	*Total Equity Risk Premium*
Country Bond Default Spread	5.00%	1.90%	6.90%
Relative Equity Market Standard Deviations	5.00%	3.39%	8.39%
Melded Approach (Bond default spread X Relative Standard Deviation$_{Bond}$)	5.00%	1.90%*1.69 = 3.22%	8.22%
Melded Approach (CDS X Relative Standard Deviation$_{CDS}$)	5.00%	2.53% *1.40=3.54%	8.54%

The three approaches that use standard deviations all yield remarkably similar equity risk premiums, but that is more the exception than the rule. In particular, the melded CDS approach offers more promise going forward, as more countries have CDS traded on them. With all three approaches, just as companies mature and become less risky over time, countries can mature and become less risky as well.

One way to adjust country risk premiums over time is to begin with the premium that emerges from the melded approach and to adjust this premium down towards either the country bond default spread or the country premium estimated from equity standard deviations. Thus, the equity risk premium will converge to the country bond default spread as we look at longer term expected returns. As an illustration, the country risk premium for Brazil would be 3.22% for the next year but decline over time to 1.90%

(country default spread) or perhaps even lower, depending upon your assessment of how Brazil's economy will evolve over time.

Implied Equity Premiums

The problem with any historical premium approach, even with substantial modifications, is that it is backward looking. Given that our objective is to estimate an updated, forward-looking premium, it seems foolhardy to put your faith in mean reversion and past data. In this section, we will consider three approaches for estimating equity risk premiums that are more forward looking.

1. DCF Model Based Premiums

When investors price assets, they are implicitly telling you what they require as an expected return on that asset. Thus, if an asset has expected cash flows of $15 a year in perpetuity, and an investor pays $75 for that asset, he is announcing to the world that his required rate of return on that asset is 20% (15/75). In this section, we expand on this intuition and argue that the current market prices for equity, in conjunction with expected cash flows, should yield an estimate on the equity risk premium.

A Stable Growth DDM Premium

It is easiest to illustrated implied equity premiums with a dividend discount model (DDM). In the DDM, the value of equity is the present value of expected dividends from the investment. In the special case where dividends are assumed to grow at a constant rate forever, we get the classic stable growth (Gordon) model:

$$\text{Value of equity} = \frac{\text{Expected Dividends Next Period}}{(\text{Required Return on Equity - Expected Growth Rate})}$$

This is essentially the present value of dividends growing at a constant rate. Three of the four inputs in this model can be obtained or estimated - the current level of the market (value), the expected dividends next period and the expected growth rate in earnings and dividends in the long term. The only "unknown" is then the required return on equity; when we solve for it, we get an implied expected return on stocks. Subtracting out the riskfree rate will yield an implied equity risk premium.

To illustrate, assume that the current level of the S&P 500 Index is 900, the expected dividend yield on the index is 2% and the expected growth rate in earnings and dividends in the long term is 7%. Solving for the required return on equity yields the following:

$$900 = (.02*900) /(r - .07)$$

Solving for r,

$$r = (18+63)/900 = 9\%$$

If the current riskfree rate is 6%, this will yield a premium of 3%.

In fact, if we accept the stable growth dividend discount model as the base model for valuing equities and assume that the expected growth rate in dividends should equate to the riskfree rate in the long term, the dividend yield on equities becomes a measure of the equity risk premium:

$$\text{Value of equity} = \frac{\text{Expected Dividends Next Period}}{(\text{Required Return on Equity - Expected Growth Rate})}$$

$$\text{Dividends/ Value of Equity} = \text{Required Return on Equity} - \text{Expected Growth rate}$$

$$\text{Dividend Yield} = \text{Required Return on Equity} - \text{Riskfree rate}$$

$$= \text{Equity Risk Premium}$$

Rozeff (1984) made this argument[92] and empirical support has been claimed for dividend yields as predictors of future returns in many studies since.[93] Note that this simple equation will break down if (a) companies do not pay out what they can afford to in dividends, i.e., they hold back cash or (b) if earnings are expected to grow at extraordinary rates for the short term.

There is another variant of this model that can be used, where we focus on earnings instead of dividends. To make this transition, though, we have to state the expected growth rate as a function of the payout ratio and return on equity (ROE) :[94]

$$\text{Growth rate} = (1 - \text{Dividends/ Earnings}) (\text{Return on equity})$$

$$= (1 - \text{Payout ratio}) (\text{ROE})$$

Substituting back into the stable growth model,

$$\text{Value of equity} = \frac{\text{Expected Earnings Next Period (Payout ratio)}}{(\text{Required Return on Equity - (1-Payout ratio) (ROE)})}$$

If we assume that the return on equity (ROE) is equal to the required return on equity (cost of equity), i.e., that the firm does not earn excess returns, this equation simplifies as follows:

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[92] Rozeff, M. S. 1984. *Dividend yields are equity risk premiums*, Journal of Portfolio Management, v11, 68-75.

[93] Fama, E. F., and K. R. French. 1988. *Dividend yields and expected stock returns*. Journal of Financial Economics, v22, 3-25.

[94] This equation for sustainable growth is discussed more fully in Damodaran, A., 2002, Investment Valuation, John Wiley and Sons.

$$\text{Value of equity} = \frac{\text{Expected Earnings Next Period}}{\text{Required Return on Equity}}$$

In this case, the required return on equity can be written as:

$$\text{Required return on equity} = \frac{\text{Expected Earnings Next Period}}{\text{Value of Equity}}$$

In effect, the inverse of the PE ratio (also referenced as the earnings yield) becomes the required return on equity, if firms are in stable growth and earning no excess returns. Subtracting out the riskfree rate should yield an implied premium:

Implied premium (EP approach) = Earnings Yield on index – Riskfree rate

In January 2014, the first of these approaches would have delivered a very low equity risk premium for the US market.

Dividend Yield = 1.96%

The second approach of netting the earnings yield against the risk free rate would have generated a more plausible number:

Earnings Yield = 5.81%:[95]

Implied premium = Earnings yield – 10-year US Treasury Bond rate
= 5.81% - 3.04% = 2.77%

Both approaches, though, draw on the dividend discount model and make strong assumptions about firms being in stable growth and/or long-term excess returns.

A Generalized Model: Implied Equity Risk Premium

To expand the model to fit more general specifications, we would make the following changes: Instead of looking at the actual dividends paid as the only cash flow to equity, we would consider potential dividends instead of actual dividends. In my earlier work (2002, 2006), the free cash flow to equity (FCFE), i.e, the cash flow left over after taxes, reinvestment needs and debt repayments, was offered as a measure of potential dividends.[96] Over the last decade, for instance, firms have paid out only about half their FCFE as dividends. If this poses too much of an estimation challenge, there is a simpler alternative. Firms that hold back cash build up large cash balances that they use over time to fund stock buybacks. Adding stock buybacks to aggregate dividends paid should give us a better measure of total cash flows to equity. The model can also be expanded to allow for a high growth phase, where earnings and dividends can grow at

[95] The earnings yield in January 2014 is estimated by dividing the aggregated earnings for the index by the index level.

[96] Damodaran, A., 2002, *Investment Valuation*, John Wiley and Sons; Damodaran, A., 2006, *Damodaran on Valuation*, John Wiley and Sons.

rates that are very different (usually higher, but not always) than stable growth values. With these changes, the value of equity can be written as follows:

$$\text{Value of Equity} = \sum_{t=1}^{t=N} \frac{E(FCFE_t)}{(1+k_e)^t} + \frac{E(FCFE_{N+1})}{(k_e - g_N)(1+k_e)^N}$$

In this equation, there are N years of high growth, $E(FCFE_t)$ is the expected free cash flow to equity (potential dividend) in year t, k_e is the rate of return expected by equity investors and g_N is the stable growth rate (after year N). We can solve for the rate of return equity investors need, given the expected potential dividends and prices today. Subtracting out the riskfree rate should generate a more realistic equity risk premium.

In a variant of this approach, the implied equity risk premium can be computed from excess return or residual earnings models. In these models, the value of equity today can be written as the sum of capital invested in assets in place and the present value of future excess returns:[97]

$$\text{Value of Equity} = \text{Book Equity today} + \sum_{t=1}^{t=\infty} \frac{\text{Net Income}_t - k_e(\text{Book Equity}_{t-1})}{(1+k_e)^t}$$

If we can make estimates of the book equity and net income in future periods, we can then solve for the cost of equity and use that number to back into an implied equity risk premium. Claus and Thomas (2001) use this approach, in conjunction with analyst forecasts of earnings growth, to estimate implied equity risk premiums of about 3% for the market in 2000.[98] Easton (2007) provides a summary of possible limitations of models that attempt to extract costs of equity from accounting data including the unreliability of book value numbers and the use of optimistic estimates of growth from analysts.[99]

Implied Equity Risk Premium: S&P 500

Given its long history and wide following, the S&P 500 is a logical index to use to try out the implied equity risk premium measure. In this section, we will begin by estimating implied equity risk premiums at the start of the years 2008-2014, and follow up by looking at the volatility in that estimate over time.

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[97] For more on excess return models, see Damodaran, A, 2006, *Valuation Approaches and Metrics: A Survey of the Theory and Evidence,* Working Paper, www.damodaran.com.

[98] Claus, J. and J. Thomas, 2001,'*Equity premia as low as three percent? Evidence from analysts' earnings forecasts for domestic and international stock markets*, Journal of Finance 56(5), 1629–1666.

[99] Easton, P., 2007, *Estimating the cost of equity using market prices and accounting data*, Foundations and Trends in Accounting, v2, 241-364.

Implied Equity Risk Premiums: Annual Estimates from 2008 to 2013

On December 31, 2007, the S&P 500 Index closed at 1468.36, and the dividend yield on the index was roughly 1.89%. In addition, the consensus estimate of growth in earnings for companies in the index was approximately 5% for the next 5 years.[100] Since this is not a growth rate that can be sustained forever, we employ a two-stage valuation model, where we allow growth to continue at 5% for 5 years, and then lower the growth rate to 4.02% (the riskfree rate) after that.[101] Table 17 summarizes the expected dividends for the next 5 years of high growth, and for the first year of stable growth thereafter:

Table 17: Estimated Dividends on the S&P 500 Index – January 1, 2008

Year	*Dividends on Index*
1	29.12
2	30.57
3	32.10
4	33.71
5	35.39
6	36.81

[a]Dividends in the first year = 1.89% of 1468.36 (1.05)

If we assume that these are reasonable estimates of the expected dividends and that the index is correctly priced, the value can be written as follows:

$$1468.36 = \frac{29.12}{(1+r)} + \frac{30.57}{(1+r)^2} + \frac{32.10}{(1+r)^3} + \frac{33.71}{(1+r)^4} + \frac{35.39}{(1+r)^5} + \frac{36.81}{(r-.0402)(1+r)^5}$$

Note that the last term in the equation is the terminal value of the index, based upon the stable growth rate of 4.02%, discounted back to the present. Solving for required return in this equation yields us a value of 6.04%. Subtracting out the ten-year treasury bond rate (the riskfree rate) yields an implied equity premium of 2.02%.

The focus on dividends may be understating the premium, since the companies in the index have bought back substantial amounts of their own stock over the last few years. Table 18 summarizes dividends and stock buybacks on the index, going back to 2001.

Table 18: Dividends and Stock Buybacks: 2001- 2007

Year	*Dividend Yield*	*Stock Buyback Yield*	*Total Yield*
2001	1.37%	1.25%	2.62%
2002	1.81%	1.58%	3.39%

[100] We used the average of the analyst estimates for individual firms (bottom-up). Alternatively, we could have used the top-down estimate for the S&P 500 earnings.

[101] The treasury bond rate is the sum of expected inflation and the expected real rate. If we assume that real growth is equal to the real interest rate, the long term stable growth rate should be equal to the treasury bond rate.

2003	1.61%	1.23%	2.84%
2004	1.57%	1.78%	3.35%
2005	1.79%	3.11%	4.90%
2006	1.77%	3.39%	5.16%
2007[a]	1.89%	4.00%	5.89%
Average total yield between 2001-2007 =			4.02%

[a]Trailing 12-month data, from September 2006 through September 2007. In January 2008, this was the information that would have been available. The actual cash yield for all of 2007 was 6.49%.

In 2007, for instance, firms collectively returned more than twice as much in the form of buybacks than they paid out in dividends. Since buybacks are volatile over time, and 2007 may represent a high-water mark for the phenomenon, we recomputed the expected cash flows, in table 19, for the next 6 years using the average total yield (dividends + buybacks) of 4.11%, instead of the actual dividends, and the growth rates estimated earlier (5% for the next 5 years, 4.02% thereafter):

Table 19: Cashflows on S&P 500 Index

Year	*Dividends+ Buybacks on Index*
1	63.37
2	66.54
3	69.86
4	73.36
5	77.02

Using these cash flows to compute the expected return on stocks, we derive the following:

$$1468.36 = \frac{63.37}{(1+r)} + \frac{66.54}{(1+r)^2} + \frac{69.86}{(1+r)^3} + \frac{73.36}{(1+r)^4} + \frac{77.02}{(1+r)^5} + \frac{77.02(1.0402)}{(r-.0402)(1+r)^5}$$

Solving for the required return and the implied premium with the higher cash flows:

Required Return on Equity = 8.39%

Implied Equity Risk Premium = Required Return on Equity - Riskfree Rate

= 8.48% - 4.02% = 4.46%

This value (4.46%) would have been our estimate of the equity risk premium on January 1, 2008.

During 2008, the S&P 500 lost just over a third of its value and ended the year at 903.25 and the treasury bond rate plummeted to close at 2.21% on December 31, 2008. Firms also pulled back on stock buybacks and financial service firms in particular cut dividends during the year. The inputs to the equity risk premium computation reflect these changes:

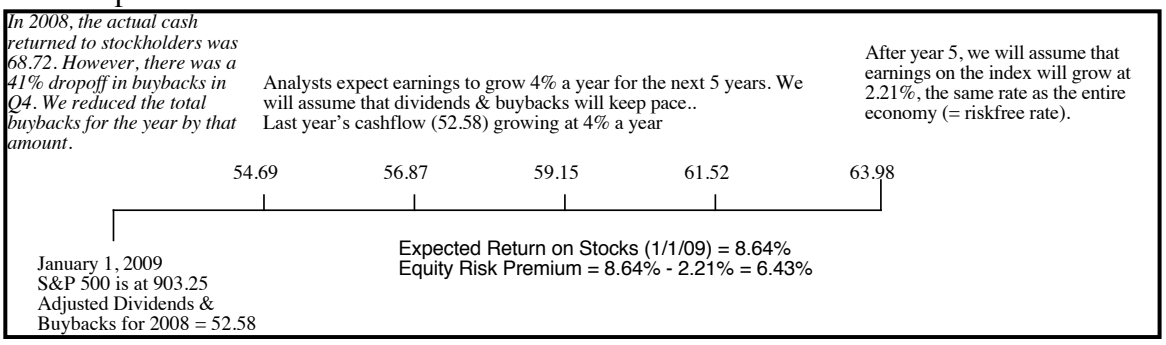
Level of the index = 903.25 (Down from 1468.36)

Treasury bond rate = 2.21% (Down from 4.02%)

Updated dividends and buybacks on the index = 52.58 (Down about 15%)

Expected growth rate = 4% for next 5 years (analyst estimates) and 2.21% thereafter (set equal to riskfree rate).

The computation is summarized below:



The resulting equation is below:

$$903.25 = \frac{54.69}{(1+r)} + \frac{56.87}{(1+r)^2} + \frac{59.15}{(1+r)^3} + \frac{61.52}{(1+r)^4} + \frac{63.98}{(1+r)^5} + \frac{63.98(1.0221)}{(r-.0221)(1+r)^5}$$

Solving for the required return and the implied premium with the higher cash flows:

Required Return on Equity = 8.64%

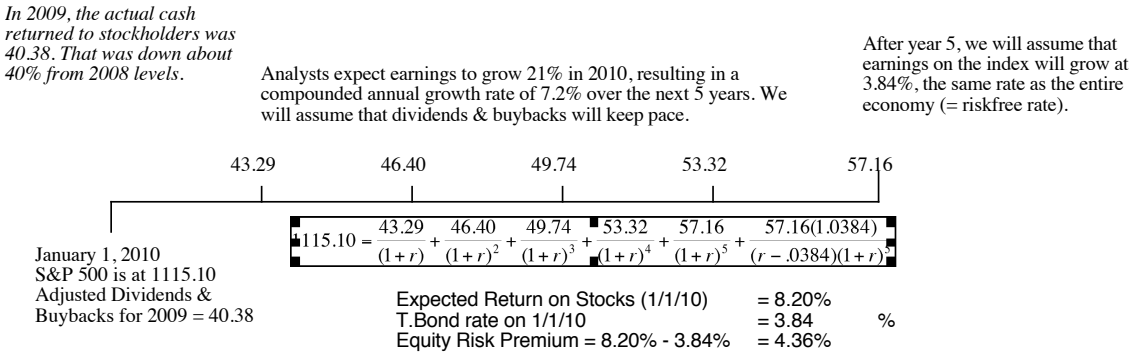
Implied Equity Risk Premium = Required Return on Equity - Riskfree Rate

= 8.64% - 2.21% = 6.43%

The implied premium rose more than 2%, from 4.37% to 6.43%, over the course of the year, indicating that investors perceived more risk in equities at the end of the year, than they did at the start and were demanding a higher premium to compensate.

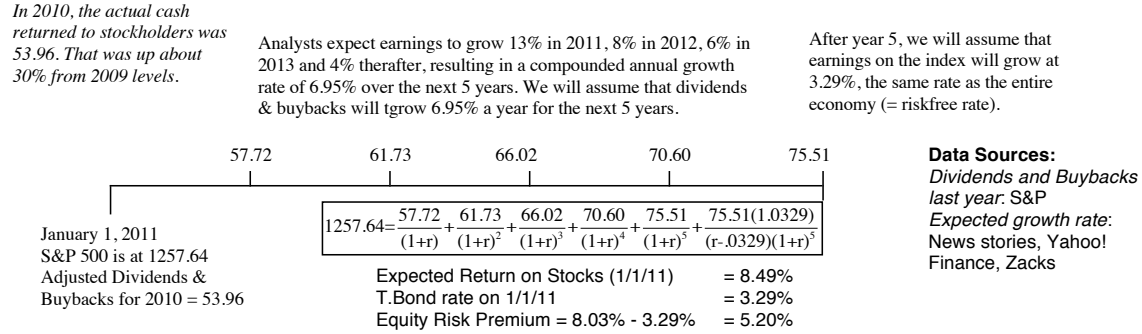
By January 2010, the fears of a banking crisis had subsided and the S&P 500 had recovered to 1115.10. However, a combination of dividend cuts and a decline in stock buybacks had combined to put the cash flows on the index down to 40.38 in 2009. That was partially offset by increasing optimism about an economic recovery and expected earnings growth for the next 5 years had bounced back to 7.2%.[102] The resulting equity risk premium is 4.36%:

[102] The expected earnings growth for just 2010 was 21%, primarily driven by earnings bouncing back to pre-crisis levels, followed by a more normal 4% earnings growth in the following years. The compounded average growth rate is $((1.21)\ (1.04)^4)^{1/5}-1 = .072$ or 7.2%.



In effect, equity risk premiums have reverted back to what they were before the 2008 crisis.

Updating the numbers to January 2011, the S&P 500 had climbed to 1257.64, but cash flows on the index, in the form of dividends and buybacks, made an even more impressive comeback, increasing to 53.96 from the depressed 2009 levels. The implied equity risk premium computation is summarized below:



The implied equity risk premium climbed to 5.20%, with the higher cash flows more than offsetting the rise in equity prices.

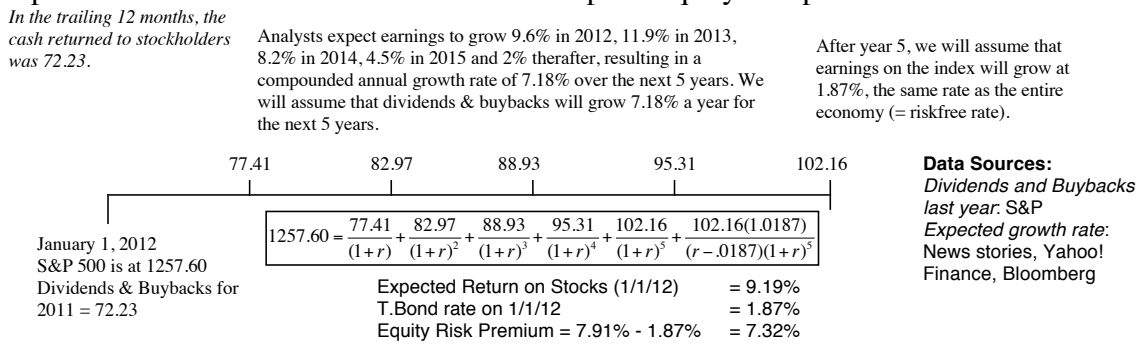
The S&P 500 ended 2011 at 1257.60, almost unchanged from the level at the start of the year. The other inputs into the implied equity risk premium equation changed significantly over the year:

a. The ten-year treasury bond rate dropped during the course of the year from 3.29% to 1.87%, as the European debt crisis caused a "flight to safety". The US did lose its AAA rating with Standard and Poor's during the course of the year, but we will continue to assume that the T.Bond rate is risk free.
b. Companies that had cut back dividends and scaled back stock buybacks in 2009, after the crisis, and only tentatively returned to the fray in 2010, returned to buying back stocks at almost pre-crisis levels. The total dividends and buybacks

for the trailing 12 months leading into January 2012 climbed to 72.23, a significant increase over the previous year.[103]

c. Analysts continued to be optimistic about earnings growth, in the face of signs of a pickup in the US economy, forecasting growth rate of 9.6% for 2012 (year 1), 11.9% in 2013, 8.2% in 2014, 4% in 2015 and 2.5% in 2016, leading to a compounded annual growth rate of 7.18% a year:.

Incorporating these inputs into the implied equity risk premium computation, we get an expected return on stocks of 9.29% and an implied equity risk premium of 7.32%:



Since the index level did not change over the course of the year, the jump in the equity risk premium from 5.20% on January 1, 2011 to 7.32% on January 1, 2012, was precipitated by two factors. The first was the drop in the ten-year treasury bond rate to a historic low of 1.87% and the second was the surge in the cash returned to stockholders, primarily in buybacks. With the experiences of the last decade fresh in our minds, we considered the possibility that the cash returned during the trailing 12 months may reflect cash that had built up during the prior two years, when firms were in their defensive posture. If that were the case, it is likely that buybacks will decline to a more normalized value in future years. To estimate this value, we looked at the total cash yield on the S&P 500 from 2002 to 2011 and computed an average value of 4.69% over the decade in table 20.

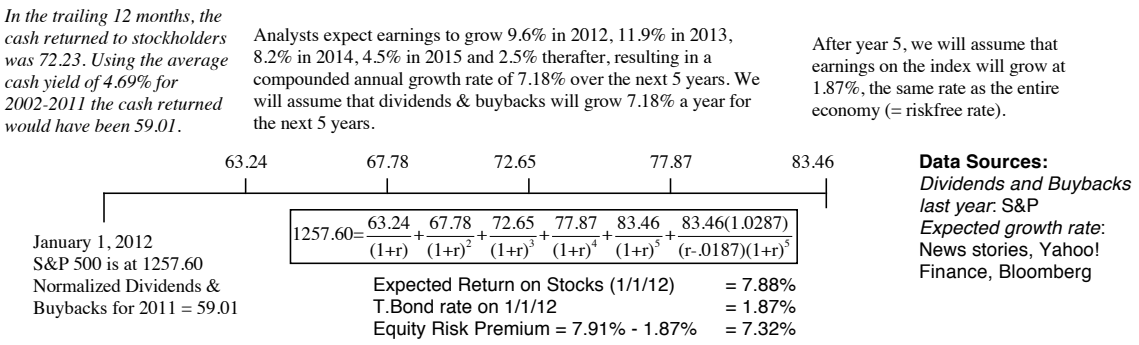
Table 20: Dividends and Buybacks on S&P 500 Index: 2002-2011

Year	Dividend Yield	Buybacks/Index	Yield
2002	1.81%	1.58%	3.39%
2003	1.61%	1.23%	2.84%
2004	1.57%	1.78%	3.35%
2005	1.79%	3.11%	4.90%
2006	1.77%	3.39%	5.16%

[103] These represented dividends and stock buybacks from October 1, 2010 to September 30, 2011, based upon the update from S&P on December 22, 2011. The data for the last quarter is not made available until late March of the following year.

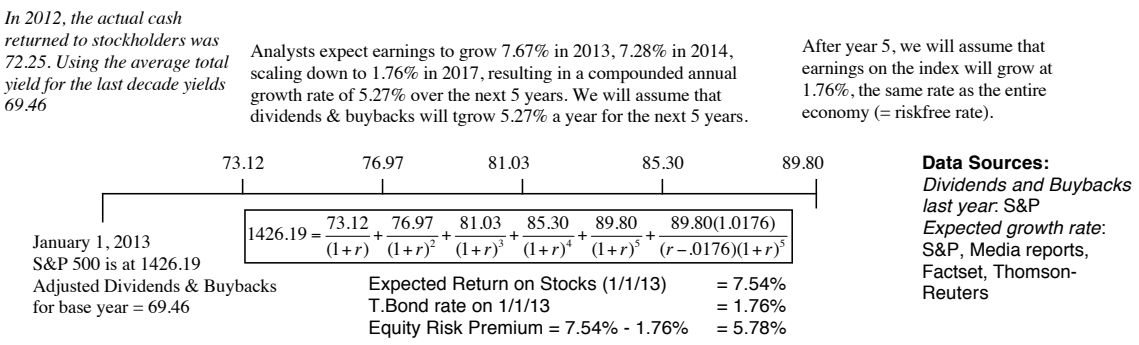
2007	1.92%	4.58%	6.49%
2008	3.15%	4.33%	7.47%
2009	1.97%	1.39%	3.36%
2010	1.80%	2.61%	4.42%
2011	2.00%	3.53%	5.54%
Average: Last 10 years =			4.69%

Assuming that the cash returned would revert to this yield provides us with a lower estimate of the cash flow (4.69% of 1257.60= 59.01) and an equity risk premium of 6.01%:



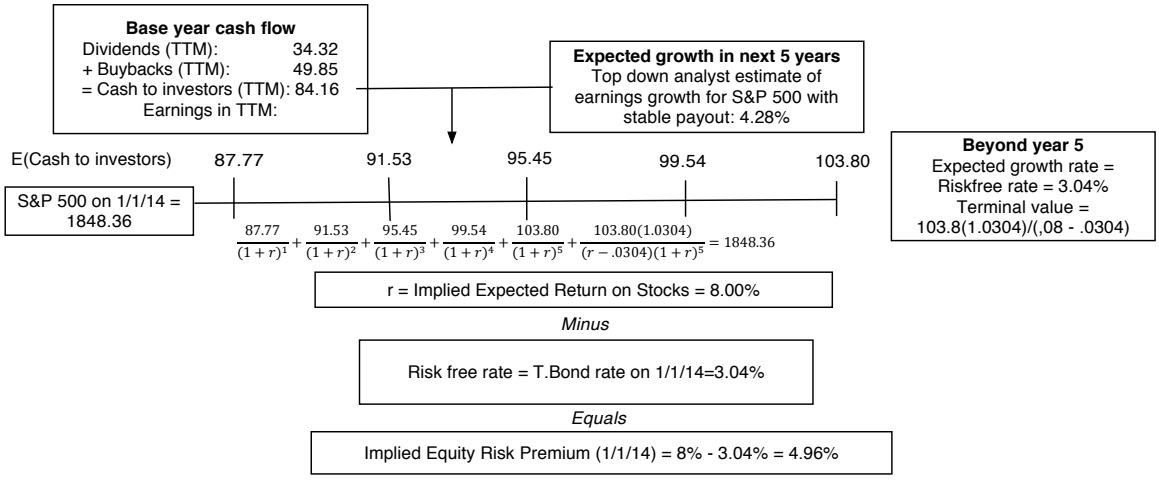
So, did the equity risk premium for the S&P 500 jump from 5.20% to 7.32%, as suggested by the raw cash yield, or from 5.20% to 6.01%, based upon the normalized yield? We would be more inclined to go with the latter, especially since the index remained unchanged over the year. Note, though, that if the cash returned by firms does not drop back in the next few quarters, we will revisit the assumption of normalization and the resulting lower equity risk premium.

By January 1, 2013, the S&P 500 climbed to 1426.19 and the treasury bond rate had dropped to 1.76%. The dividends and buybacks were almost identical to the prior year and the smoothed out cash returned (using the average yield over the prior 10 years) climbed to 69.46. Incorporating the lower growth expectations leading into 2013, the implied equity risk premium dropped to 5.78% on January 1, 2013:



Note that the chasm between the trailing 12-month cash flow premium and the smoother cash yield premium that had opened up at the start of 2012 had narrowed. The trailing 12-month cash flow premium was 6%, just 0.22% higher than the 5.78% premium obtained with the smoothed out cash flow.

After a good year for stocks, the S&P 500 was at 1848.36 on January 1, 2014, up 29.6% over the prior year, and cash flows also jumped to 84.16 over the trailing 12 months (ending September 30, 2013), up 16.48% over the prior year. Incorporating an increase in the US ten-year treasury bond rate to 3.04%, the implied equity risk premium at the start of 2014 was 4.96%.



A Term Structure for Equity Risk Premiums

When we estimate an implied equity risk premium, from the current level of the index and expected future cash flows, we are estimating a compounded average equity risk premium over the long term. Thus, the 6.01% estimate of the equity risk premium at the start of 2012 is the geometric average of the annualized equity risk premiums in future years and is analogous to the yield to maturity on a long term bond.

But is it possible that equity risk premiums have a term structure, just as interest rates do? Absolutely. In a creative attempt to measure the slope of the term structure of equity risk premiums, Binsberger, Brandt and Koijen (2012) use dividend strips, i.e., short term assets that pay dividends for finite time periods (and have no face value), to extract equity risk premiums for the short term as opposed to the long term. Using dividend strips on the S&P 500 to extract expected returns from 1996 to 2009, they find that equity risk premiums are higher for shorter term claims than for longer term claims, by approximately 2.75%.[104] Their findings are contested by Boguth, Carlson, Fisher and

[104] Binsbergen, J. H. van, Michael W. Brandt, and Ralph S. J. Koijen, 2012, *On the timing and pricing*

Simutin (2011), who note that small market pricing frictions are amplified when valuing synthetic dividend strips and that using more robust return measures results in no significant differences between short term and longer term equity risk premiums.[105]

While this debate will undoubtedly continue, the relevance to valuation and corporate finance practice is questionable. Even if you could compute period-specific equity risk premiums, the effect on value of using these premiums (instead of the compounded average premium) would be small in most valuations. To illustrate, your valuation of an asset, using an equity risk premium of 7% for the first 3 years and 5.88% thereafter[106], at the start of 2012, would be very similar to the value you would have obtained using 6.01% as your equity risk premium for all time periods. The only scenario where using year-specific premiums would make a material difference would be in the valuation of an asset or investment with primarily short-term cash flows, where using a higher short term premium will yield a lower (and perhaps more realistic) value for the asset.

Time Series Behavior for S&P 500 Implied Premium

As the inputs to the implied equity risk premium, it is quite clear that the value for the premium will change not just from day to day but from one minute to the next. In particular, movements in the index will affect the equity risk premium, with higher (lower) index values, other things remaining equal, translating into lower (higher) implied equity risk premiums. In Figure 9, we chart the implied premiums in the S&P 500 from 1960 to 2013:

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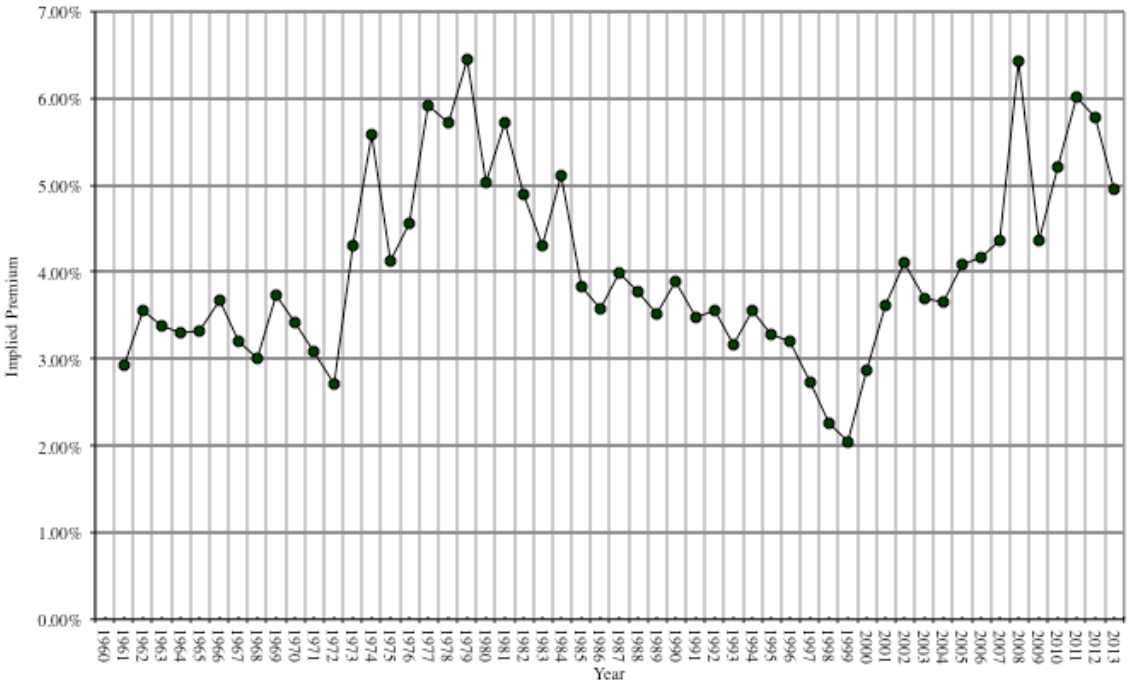
of dividends, American Economic Review, v102, 1596-1618.

[105] Boguth, O., M. Carlson, A. Fisher and M. Simutin, 2011, *Dividend Strips and the Term Structure of Equity Risk Premia: A Case Study of Limits to Arbitrage*, Working Paper, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1931105. In a response, Binsbergen, Brandt and Koijen argue that their results hold even if traded dividend strips (rather than synthetic strips) are used.

[106] The compounded average premium over time, using a 7% equity risk premium for the first 3 years and 5.88% thereafter, is roughly 6.01%.

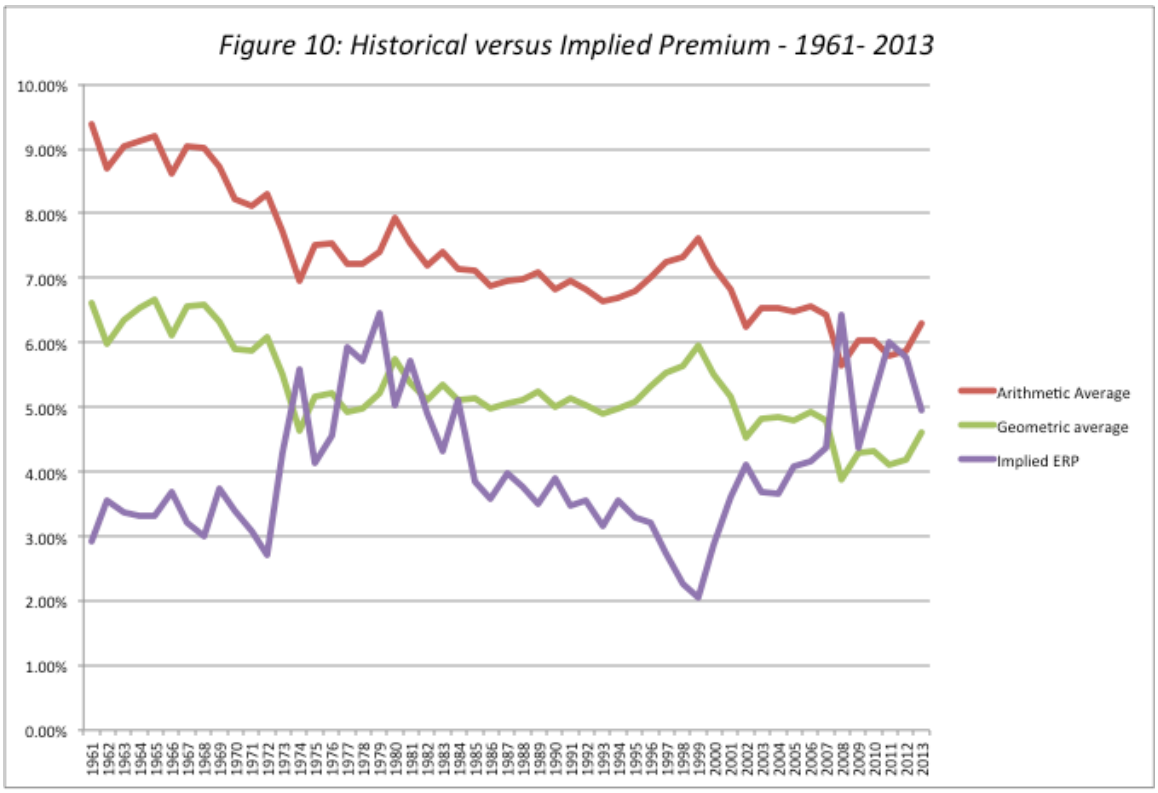
Figure 9: Implied Premium for US Equity Market



In terms of mechanics, we used potential dividends (including buybacks) as cash flows, and a two-stage discounted cash flow model; the estimates for each year are in appendix 6.[107] Looking at these numbers, we would draw the following conclusions:

- The implied equity premium has generally been lower than the historical risk premium for the US equity market for most of the last few decades. To provide a contrast, we compare the implied equity risk premiums each year to the historical risk premiums for stocks over treasury bonds, using both geometric and arithmetic averages, each year from 1961 to 2013 in figure 10:

[107] We used analyst estimates of growth in earnings for the 5-year growth rate after 1980. Between 1960 and 1980, we used the historical growth rate (from the previous 5 years) as the projected growth, since analyst estimates were difficult to obtain. Prior to the late 1980s, the dividends and potential dividends were very similar, because stock buybacks were uncommon. In the last 20 years, the numbers have diverged.



The arithmetic average premium, which is used by many practitioners, has been significantly higher than the implied premium over almost the entire fifty-year period (with 2009 and 2011 being the only exceptions). The geometric premium does provide a more interesting mix of results, with implied premiums exceeding historical premiums in the mid-1970s and again since 2008.

- The implied equity premium did increase during the seventies, as inflation increased. This does have interesting implications for risk premium estimation. Instead of assuming that the risk premium is a constant, and unaffected by the level of inflation and interest rates, which is what we do with historical risk premiums, would it be more realistic to increase the risk premium if expected inflation and interest rates go up? We will come back and address this question in the next section.
- While historical risk premiums have generally drifted down for the last few decades, there is a strong tendency towards mean reversion in implied equity premiums. Thus, the premium, which peaked at 6.5% in 1978, moved down towards the average in the 1980s. By the same token, the premium of 2% that we observed at the end of the dot-com boom in the 1990s quickly reverted back to the average, during the market correction from 2000-2003.[108] Given this tendency, it is possible that we can end up

[108] Arnott, Robert D., and Ronald Ryan, 2001, *The Death of the Risk Premium: Consequences of the*

with a far better estimate of the implied equity premium by looking at not just the current premium, but also at historical trend lines. We can use the average implied equity premium over a longer period, say ten to fifteen years. Note that we do not need as many years of data to make this estimate as we do with historical premiums, because the standard errors tend to be smaller.

Finally, the crisis of 2008 was unprecedented in terms of its impact on equity risk premiums. Implied equity risk premiums rose more during 2008 than in any one of the prior 50 years, with much of the change happening in a fifteen week time period towards the end of the year. While much of that increase dissipated in 2009, as equity risk premiums returned to pre-crisis levels, equity risk premiums have remained more volatile since 2008. In the next section, we will take a closer look at this time period.

Implied Equity Risk Premiums during a Market Crisis and Beyond

When we use historical risk premiums, we are, in effect, assuming that equity risk premiums do not change much over short periods and revert back over time to historical averages. This assumption was viewed as reasonable for mature equity markets like the United States, but was put under a severe test during the market crisis that unfolded with the fall of Lehman Brothers on September 15, and the subsequent collapse of equity markets, first in the US, and then globally.

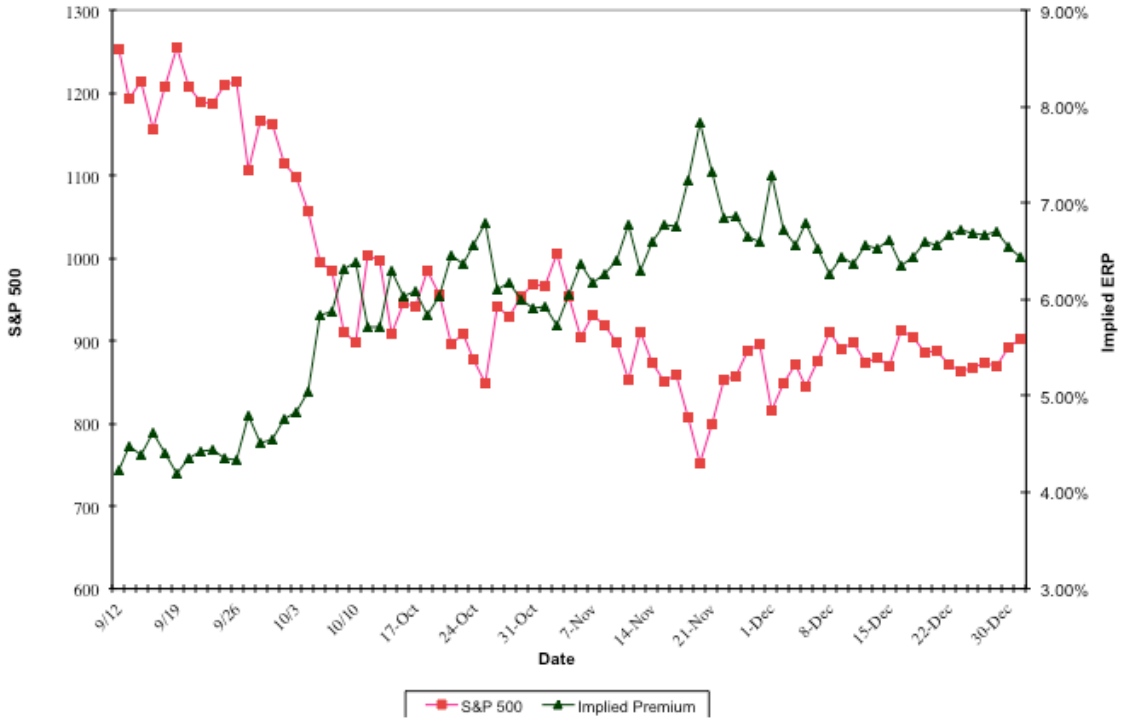
Since implied equity risk premiums reflect the current level of the index, the 75 trading days between September 15, 2008, and December 31, 2008, offer us an unprecedented opportunity to observe how much the price charged for risk can change over short periods. In figure 11, we depict the S&P 500 on one axis and the implied equity risk premium on the other. To estimate the latter, we used the level of the index and the treasury bond rate at the end of each day and used the total dollar dividends and buybacks over the trailing 12 months to compute the cash flows for the most recent year.[109] We also updated the expected growth in earnings for the next 5 years, but that number changed only slowly over the period. For example, the total dollar dividends and buybacks on the index for the trailing 12 months of 52.58 resulted in a dividend yield of 4.20% on September 12 (when the index closed at 1252) but jumped to 4.97% on October 6, when the index closed at 1057.[110]

1990s, Journal of Portfolio Management, v27, 61-74. They make the same point about reduction in implied equity risk premiums that we do. According to their calculations, though, the implied equity risk premium in the late 1990s was negative.

[109] This number, unlike the index and treasury bond rate, is not updated on a daily basis. We did try to modify the number as companies in the index announced dividend suspensions or buyback modifications.

[110] It is possible, and maybe even likely, that the banking crisis and resulting economic slowdown was leading some companies to reassess policies on buybacks. Alcoa, for instance, announced that it was terminating stock buybacks. However, other companies stepped up buybacks in response to lower stock

Figure 11: Implied Equity Risk Premium - 9/12- 12/31/08



In a period of a month, the implied equity risk premium rose from 4.20% on September 12 to 6.39% at the close of trading of October 10 as the S&P moved from 1250 down to 903. Even more disconcertingly, there were wide swings in the equity risk premium within a day; in the last trading hour just on October 10, the implied equity risk premium ranged from a high of 6.6% to a low of 6.1%. Over the rest of the year, the equity risk premium gyrated, hitting a high of 8% in late November, before settling into the year-end level of 6.43%.

The volatility captured in figure 12 was not restricted to just the US equity markets. Global equity markets gyrated with and sometimes more than the US, default spreads widened considerably in corporate bond markets, commercial paper and LIBOR rates soared while the 3-month treasury bill rate dropped close to zero and the implied volatility in option markets rose to levels never seen before. Gold surged but other commodities, such as oil and grains, dropped. Not only did we discover how intertwined equity markets are around the globe but also how markets for all risky assets are tied together. We will explicitly consider these linkages as we go through the rest of the paper.

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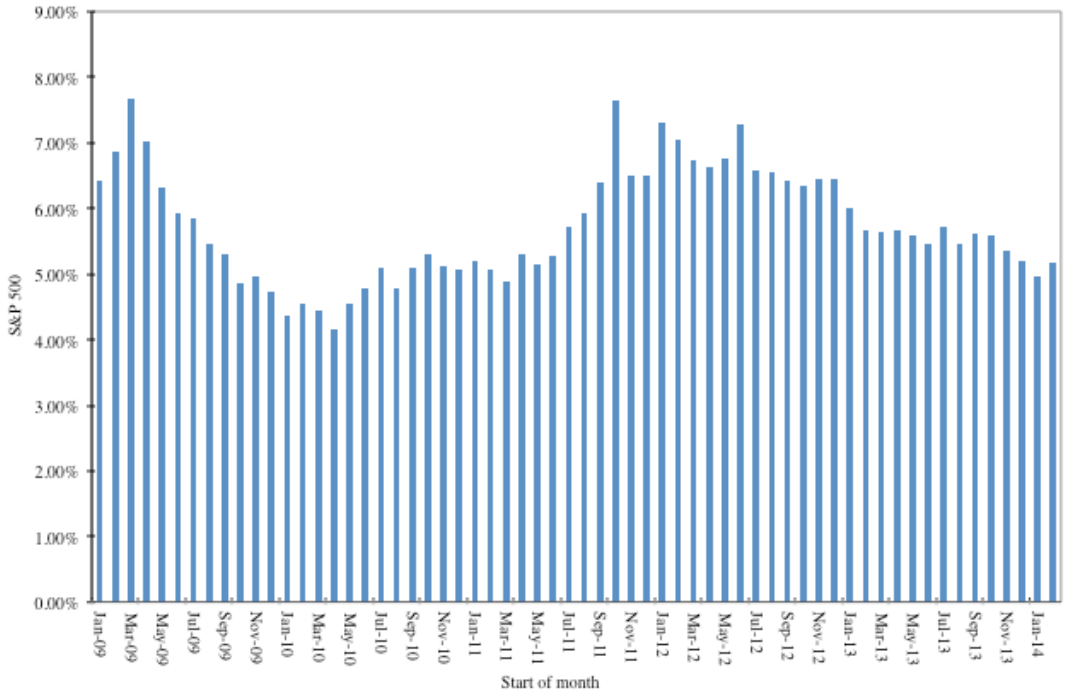
prices. If the total cash return was dropping, as the market was, the implied equity risk premiums should be lower than the numbers that we have computed.

There are two ways in which we can view this volatility. One the one side, proponents of using historical averages (either of actual or implied premiums) will use the day-to-day volatility in market risk premiums to argue for the stability of historical averages. They are implicitly assuming that when the crisis passes, markets will return to the status quo. On the other hand, there will be many who point to the unprecedented jump in implied premiums over a few weeks and note the danger of sticking with a "fixed" premium. They will argue that there are sometimes structural shifts in markets, i.e. big events that change market risk premiums for long periods, and that we should be therefore be modifying the risk premiums that we use in valuation as the market changes around us. In January 2009, in the context of equity risk premiums, the first group would have argued we should ignore history (both in terms of historical returns and implied equity risk premiums) and move to equity risk premiums of 6%+ for mature markets (and higher for emerging markets whereas the second would have made a case for sticking with a historical average, which would have been much lower than 6.43%.

The months since the crisis ended in 2008 have seen ups and downs in the implied premium, with clear evidence that the volatility in the equity risk premium has increased over the last few years. In figure 12, we report on the monthly equity risk premiums for the S&P 500 from January 2009 through February 2014:

Figure 12: Implied ERP by month: S&P 500
January 2009- Current



Note that the equity risk premium dropped from its post-crisis highs in 2010 but climbed back in 2011 to 6% or higher, before dropping in 2013 back to 5%.

On a personal note, I believe that the very act of valuing companies requires taking a stand on the appropriate equity risk premium to use. For many years prior to September 2008, I used 4% as my mature market equity risk premium when valuing companies, and assumed that mean reversion to this number (the average implied premium over time) would occur quickly and deviations from the number would be small. Though mean reversion is a powerful force, I think that the banking and financial crisis of 2008 has created a new reality, i.e., that equity risk premiums can change quickly and by large amounts even in mature equity markets. Consequently, I have forsaken my practice of staying with a fixed equity risk premium for mature markets, and I now vary it year-to-year, and even on an intra-year basis, if conditions warrant. After the crisis, in the first half of 2009, I used equity risk premiums of 6% for mature markets in my valuations. As risk premiums came down in 2009, I moved back to using a 4.5% equity risk premium for mature markets in 2010. With the increase in implied premiums at the start of 2011, my valuations for the year were based upon an equity risk premium of 5% for mature markets and I increased that number to 6% for 2012. In 2014, I will be using a lower equity risk premium (5.00%), reflecting the drop from 2012. While some may view this shifting equity risk premium as a sign of weakness, I would frame it differently. When valuing individual companies, I want my valuations to reflect my assessments of the company and not my assessments of the overall equity market. Using equity risk premiums that are very different from the implied premium will introduce a market view into individual company valuations.

Determinants of Implied Premiums

One of the advantages of estimating implied equity risk premiums, by period, is that we can track year to year changes in that number and relate those changes to shifts in interest rates, the macro environment or even to company characteristics. By doing so, not only can we get a better understanding of what causes equity risk premiums to change over time, but we are also able to come up with better estimates of future premiums.

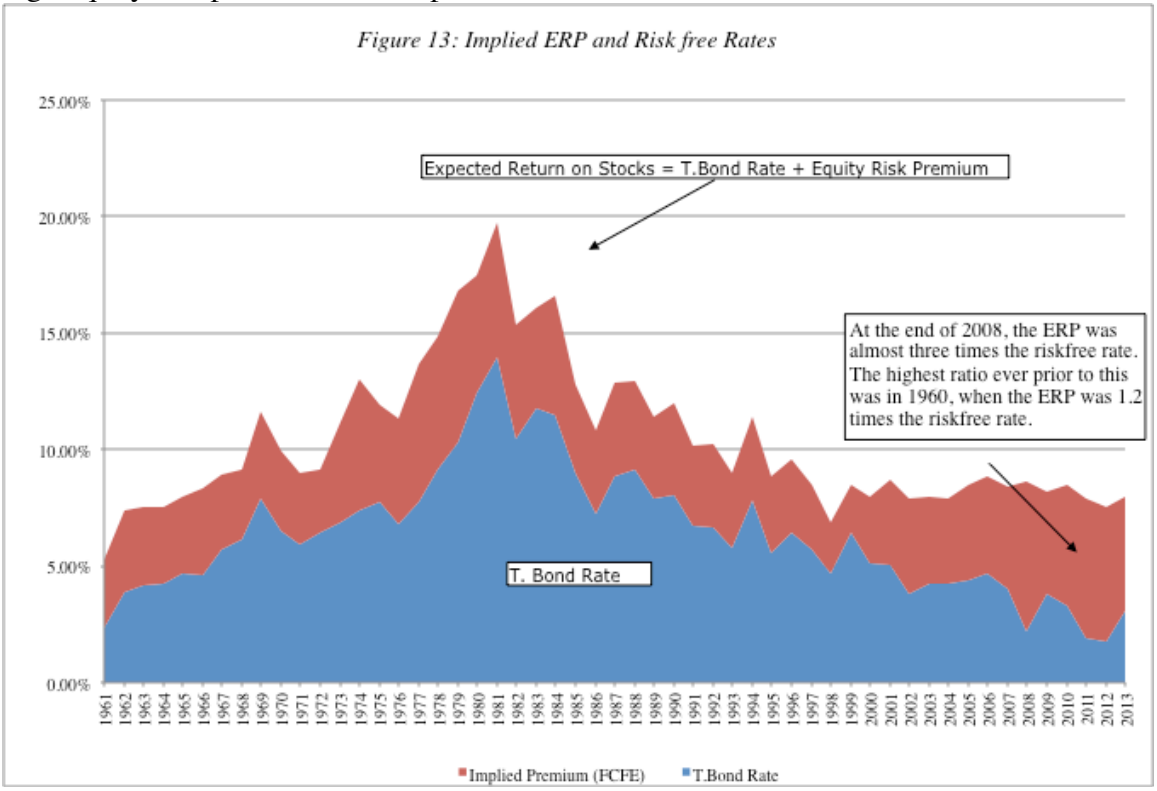
Implied ERP and Interest rates

In much of valuation and corporate finance practice, we assume that the equity risk premium that we compute and use is unrelated to the level of interest rates. In particular, the use of historical risk premiums, where the premium is based upon an average premium earned over shifting risk free rates, implicitly assumes that the level of the premium is unchanged as the risk free rate changes. Thus, we use the same equity risk

premium of 4.2% (the historical average for 1928-2012) on a risk free rate of 1.76% in 2012, as we would have, if the risk free rate had been 10%.

But is this a reasonable assumption? How much of the variation in the premium over time can be explained by changes in interest rates? Put differently, do equity risk premiums increase as the risk free rate increases or are they unaffected? To answer this question, we considered looked at the relationship between the implied equity risk premium and the treasury bond rate (risk free rate). As can be seen in figure 13, the implied equity risk premiums were highest in the 1970s, when interest rates and inflation were also high. However, there is contradictory evidence between 2008 and 2013, when high equity risk premiums accompanied low risk free rates.

Figure 13: Implied ERP and Risk free Rates



To examine the relationship between equity risk premiums and risk free rates, we ran a regression of the implied equity risk premium against both the level of long-term rates (the treasury bond rate) and the slope of the yield curve (captured as the difference between the 10-year treasury bond rate and the 3-month T.Bill rate), with the t statistics reported in brackets below each coefficient:

$$\text{Implied ERP} = 3.51\% + \underset{(8.45)}{0.0755}\ (\text{T.Bond Rate}) + \underset{(1.40)}{0.0441}\ (\text{T.Bond} - \text{T.Bill}) \quad \underset{(0.36)}{R^2 = 4.82\%}$$

There is a mildly positive relationship between the T.Bond rate and implied equity risk premiums: every 1% increase in the treasury bond rate increases the equity risk premium

by 0.08%. The slope of the yield curve seems to have little impact on the implied equity risk premium. Removing the latter variable and running the regression again:

Implied ERP = 3.57% + 0.0738 (T.Bond Rate) R^2=3.65%
(9.75) (1.39)

This regression does provide support, albeit weak, for the view that equity risk premiums should not be constant but should be linked to the level of interest rates. In fact, the regression can be used to estimate an equity risk premium, conditional on current interest rates. On February 23, 2014, for instance, when the 10-year treasury bond rate was 2.75%, the implied equity risk premium would have been computed as follows:

Implied ERP = = 3.57% + 0.0738 (2.75%) = 3.78%

This would have been below the observed implied equity risk premium of about 4.61% and the average implied equity risk premium of 4.00% between 1960 and 2013. Put differently, given the low level of risk free rates in 2013 and the historical relationship between equity risk premiums and risk free rates, we would have expected the equity risk premium to be a much lower number (3.78%) than the actual number (4.62%).

Implied ERP and Macroeconomic variables

While we considered the interaction between equity risk premiums and interest rates in the last section, the analysis can be expanded to include other macroeconomic variables including economic growth, inflation rates and exchange rates. Doing so may give us a way of estimating an "intrinsic' equity risk premium, based upon macro economic variables, that is less susceptible to market moods and perceptions.

To explore the relationship, we estimated the correlation, between the implied equity risk premiums that we estimated for the S&P 500 and three macroeconomic variables – real GDP growth for the US, inflation rates (CPI) and exchange rates (trade weighted dollar), using data from 1973 to 2013, in table 21 (t statistics in brackets):

Table 21: Correlation Matrix: ERP and Macroeconomic variables: 1973-2013

	ERP	*Weighted Dollar*	*Real GDP*	*CPI*
ERP	1.0000			
Weighted dollar	0.0992 (0.61)	1.0000		
Real GDP	-0.3475 (2.28)**	-0.1300 (0.80)	1.0000	
CPI	0.4492 (3.10)**	0.1474 (0.17)	-0.1612 (1.01)	1.0000

** Statistically significant

The implied equity risk premium is negatively correlated with GDP growth, increasing as GDP growth decreases or becomes more negative. The ERP is also affected by inflation, with higher inflation going hand-in-hand with higher equity risk premiums.[111]

Following up on this analysis, we regressed equity risk premiums against the inflation rate and GDP growth, using data from 1961 to 2013:

Implied ERP = 3.96% - 0.1467 Real GDP growth + 0.1364 (Inflation rate) R^2= 30.68%
(13.12) (2.67) (3.11)

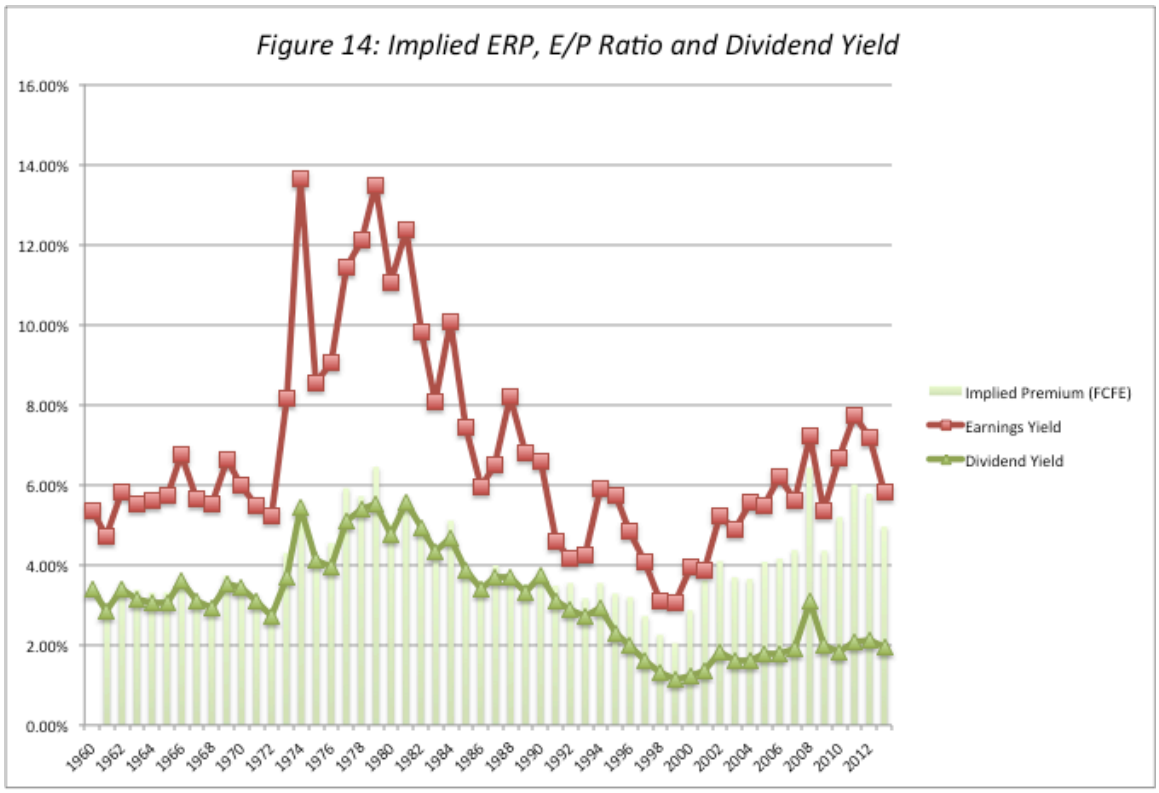
Based on this regression, every 1% increase in the inflation rate increases the equity risk premium by approximately 0.1364%, whereas every 1% increase in the growth rate in real GDP decreases the implied equity risk premium by 0.1467%.

From a risk perspective, it is not the level of GDP growth that matters, but uncertainty about that level; you can have low and stable economic growth and high and unstable economic growth. Since 2008, the economies of both developed and emerging markets have become more unstable over time and upended long held beliefs about developed economies. It will be interesting to see if equity risk premiums become more sensitive to real economic growth in this environment.

Implied ERP, Earnings Yields and Dividend Yields

Earlier in the paper, we noted that the dividend yield and the earnings yield (net of the risk free rate) can be used as proxies for the equity risk premium, if we make assumptions about future growth (stable growth, with the dividend yield) or expected excess returns (zero, with the earnings yield). In figure 14, we compare the implied equity risk premiums that we computed to the earnings and dividend yields for the S&P 500 from 1961 to 2013:

[111] The correlation was also computed for lagged and leading versions of these variables, with two material differences: the equity risk premium is negatively correlated with leading inflation rates and positively correlated with a leading weighted dollar.



Note that the dividend yield is a very close proxy for the implied equity risk premium until the late 1980s, when the two measures decoupled, a phenomenon that is best explained by the rise of stock buybacks as an alternative way of returning cash to stockholders.

The earnings yield, with the riskfree rate netted out, has generally not been a good proxy for the implied equity risk premium and would have yielded negative values for the equity risk premium (since you have to subtract out the risk free rate from it) through much of the 1990s. However, it does move with the implied equity risk premium. The difference between the earnings to price measure and the implied ERP can be attributed to a combination of higher earnings growth and excess returns that investors expect companies to deliver in the future. Analysts and academic researchers who use the earnings to price ratio as a proxy for forward-looking equity risk premiums may therefore end up with significant measurement error in their analyses.

Implied ERP and Technical Indicators

Earlier in the paper, we noted that any market timing forecast can be recast as a view on the future direction of the equity risk premium. Thus, a view that the market is under (over) priced and likely to go higher (lower is consistent with a belief that equity risk premiums will decline (increase) in the future. Many market timers do rely on technical indicators, such as moving averages and momentum measures, to make their

judgment about market direction. To evaluate whether these approaches have a basis, you would need to look at how these measures are correlated with changes in equity risk premiums.

In a test of the efficacy of technical indicators, Neely, Rapach, Tu and Zhou (2011) compare the predictive power of macroeconomic/fundamental indications (including the interest rate, inflation, GDP growth and earnings/dividend yield numbers) with those of technical indicators (moving average, momentum and trading volume) and conclude that the latter better explain movements in stock returns.[112] They conclude that a composite prediction, that incorporates both macroeconomic and technical indicators, is superior to using just one set or the other of these variables. Note, however, that their study focused primarily on the predictability of stock returns over the next year and not on longer term equity risk premiums.

Extensions of Implied Equity Risk Premium

The process of backing out risk premiums from current prices and expected cashflows is a flexible one. It can be expanded into emerging markets to provide estimates of risk premiums that can replace the country risk premiums we developed in the last section. Within an equity market, it can be used to compute implied equity risk premiums for individual sectors or even classes of companies.

Other Equity Markets

The advantage of the implied premium approach is that it is market-driven and current, and does not require any historical data. Thus, it can be used to estimate implied equity premiums in any market, no matter how short its history, It is, however, bounded by whether the model used for the valuation is the right one and the availability and reliability of the inputs to that model. Earlier in this paper, we estimated country risk premiums for Brazil, using default spreads and equity market volatile. To provide a contrast, we estimated the implied equity risk premium for the Brazilian equity market in September 2009, from the following inputs.

- The index (Bovespa) was trading at 61,172 on September 30, 2009, and the dividend yield on the index over the previous 12 months was approximately 2.2%. While stock buybacks represented negligible cash flows, we did compute the FCFE for companies in the index, and the aggregate FCFE yield across the companies was 4.95%.

[112] Neely, C.J., D.E. Rapach, J. Tu and G. Zhou, 2011, *Forecasting the Equity Risk Premium: The Role of Technical Indicators*, Working Paper, http://ssrn.com/abstract=1787554.

- Earnings in companies in the index are expected to grow 6% (in US dollar terms) over the next 5 years, and 3.45% (set equal to the treasury bond rate) thereafter.
- The riskfree rate is the US 10-year treasury bond rate of 3.45%.

The time line of cash flows is shown below:

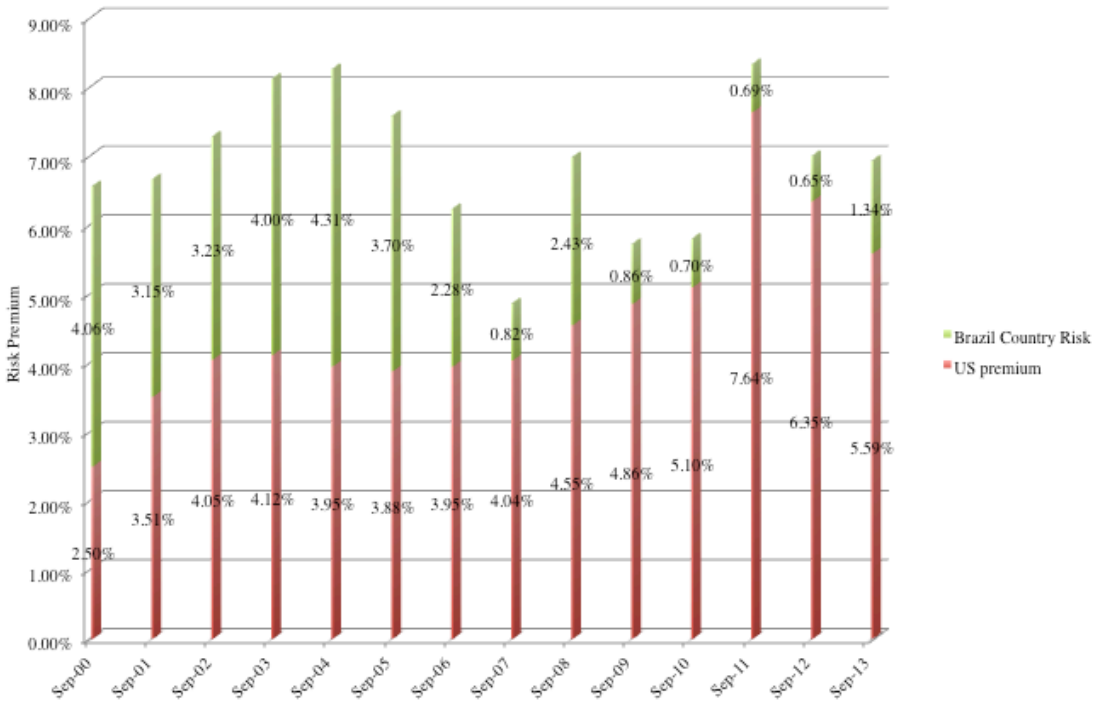
$$61,272 = \frac{3210}{(1+r)} + \frac{3,402}{(1+r)^2} + \frac{3,606}{(1+r)^3} + \frac{3,821}{(1+r)^4} + \frac{4,052}{(1+r)^5} + \frac{4,052(1.0345)}{(r-.0345)(1+r)^5}$$

These inputs yield a required return on equity of 9.17%, which when compared to the treasury bond rate of 3.45% on that day results in an implied equity premium of 5.72%. For simplicity, we have used nominal dollar expected growth rates[113] and treasury bond rates, but this analysis could have been done entirely in the local currency.

One of the advantages of using implied equity risk premiums is that that they are more sensitive to changing market conditions. The implied equity risk premium for Brazil in September 2007, when the Bovespa was trading at 73512, was 4.63%, lower than the premium in September 2009, which in turn was much lower than the premium prevailing in September 2013. In figure 15, we trace the changes in the implied equity risk premium in Brazil from September 2000 to September 2013 and compare them to the implied premium in US equities:

[113] The input that is most difficult to estimate for emerging markets is a long-term expected growth rate. For Brazilian stocks, I used the average consensus estimate of growth in earnings for the largest Brazilian companies which have ADRs listed on them. This estimate may be biased, as a consequence.

Figure 15: Implied Equity Risk Premium - Brazil



Implied equity risk premiums in Brazil declined steadily from 2003 to 2007, with the September 2007 numbers representing a historic low. They surged in September 2008, as the crisis unfolded, fell back in 2009 and 2010 but increased again in 2011. In fact, the Brazil portion of the implied equity risk premium fell to its lowest level in ten years in September 2010, a phenomenon that remained largely unchanged in 2011 and 2012. A correction in emerging markets in 2013 pushed stock prices in Brazil down and the premium back up to 1.34% in September 2013.

Computing and comparing implied equity risk premiums across multiple equity markets allows us to pinpoint markets that stand out, either as over priced (because their implied premiums are too low, relative to other markets) or under priced (because their premiums at too high, relative to other markets). In September 2007, for instance, the implied equity risk premiums in India and China were roughly equal to or even lower than the implied premium for the United States, computed at the same time. Even an optimist on future growth these countries would be hard pressed to argue that equity markets in these markets and the United States were of equivalent risk, which would lead us to conclude that these stocks were overvalued relative to US companies.

One final note is worth making. Over the last decade, the implied equity risk premiums in the largest emerging markets – India, China and Brazil- have all declined

substantially, relative to developed markets. In table 22, we summarize implied equity risk premiums for developed and emerging markets from 2001 and 2013, making simplistic assumptions about growth and stable growth valuation models:[114]

Table 22: Developed versus Emerging Market Equity Risk Premiums

	PBV Developed	PBV Emerging	ROE Developed	ROE Emerging	US T.Bond rate	Growth rate Developed	Growth rate Emerging	Cost of equity (Developed)	Cost of equity (Emerging)	Differential ERP
2004	2.00	1.19	10.81%	11.65%	4.22%	3.72%	5.22%	7.27%	10.62%	3.36%
2005	2.09	1.27	11.12%	11.93%	4.39%	3.89%	5.39%	7.35%	10.54%	3.19%
2006	2.03	1.44	11.32%	12.18%	4.70%	4.20%	5.70%	7.71%	10.20%	2.49%
2007	1.67	1.67	10.87%	12.88%	4.02%	3.52%	5.02%	7.92%	9.73%	1.81%
2008	0.87	0.83	9.42%	11.12%	2.21%	1.71%	3.21%	10.57%	12.74%	2.17%
2009	1.20	1.34	8.48%	11.02%	3.84%	3.34%	4.84%	7.62%	9.45%	1.83%
2010	1.39	1.43	9.14%	11.22%	3.29%	2.79%	4.29%	7.36%	9.14%	1.78%
2011	1.12	1.08	9.21%	10.04%	1.88%	1.38%	2.88%	8.37%	9.51%	1.14%
2012	1.17	1.18	9.10%	9.33%	1.76%	1.26%	2.76%	7.96%	8.33%	0.37%
Jun-13	1.17	1.17	8.79%	9.37%	2.55%	2.05%	3.55%	7.81%	8.52%	0.71%

The trend line from 2004 to 2012 is clear as the equity risk premiums, notwithstanding a minor widening in 2008, have converged in developed and emerging markets, suggesting that globalization has put "emerging market risk" into developed markets, while creating "developed markets stability factors" (more predictable government policies, stronger legal and corporate governance systems, lower inflation and stronger currencies) in emerging markets. In 2013, we did see a correction in emerging markets that pushed the premium back up, albeit to a level that was still lower than it was prior to 2010.

Sector premiums

Using current prices and expected future cash flows to back out implied risk premiums is not restricted to market indices. We can employ the approach to estimate the implied equity risk premium for a specific sector at a point in time. In September 2008, for instance, there was a widely held perception that investors were attaching much higher equity risk premiums to commercial bank stocks, in the aftermath of the failures of Fannie Mae, Freddie Mac, Bear Stearns and Lehman. To test this proposition, we took a look at the S&P Commercial Bank index, which was trading at 318.26 on September 12, 2008, with an expected dividend yield of 5.83% for the next 12 months. Assuming that these dividends will grow at 4% a year for the next 5 years and 3.60% (the treasury bond rate) thereafter, well below the nominal growth rate in the overall economy, we arrived at the following equation:

$$318.26 = \frac{19.30}{(1+r)} + \frac{20.07}{(1+r)^2} + \frac{20.87}{(1+r)^3} + \frac{21.71}{(1+r)^4} + \frac{22.57}{(1+r)^5} + \frac{22.57(1.036)}{(r-.036)(1+r)^5}$$

Solving for the expected return yields a value of 9.74%, which when netted out against the riskfree rate at the time (3.60%) yields an implied premium for the sector:

[114] The equation used to compute the ERP is a simplistic one, based on the assumptions that the countries are in stable growth and that the return on equity in each country is a predictor of future return on equity:
PBV = (ROE – g)/ (Cost of equity –g)
Cost of equity = [PBV/(ROE-g)] + g

Implied ERP for Banking in September 2008 = 9.74% - 3.60% = 6.14%

How would we use this number? One approach would be to compare it to the average implied premium in this sector over time, with the underlying assumption that the value will revert back to the historical average for the sector. The implied equity risk premium for commercial banking stocks was close to 4% between 2005 and 2007, which would lead to the conclusion that banking stocks were undervalued in September 2008. The other is to assume that the implied equity premium for a sector is reflective of perceptions of future risk in that sector; in September 2008, there can be no denying that financial service companies faced unique risks and the market was reflecting these risks in prices. As a postscript, the implied equity risk premium for financial service firms was 5.80% in January 2012, just below the market implied premium at the time (6.01%), suggesting that some of the post-crisis fear about banking stocks had receded.

A note of caution has to be added to about sector-implied premiums. Since these risk premiums consolidate both sector risk and market risk, it would be inappropriate to multiply these premiums by conventional betas, which are measures of sector risk. Thus, multiplying the implied equity risk premium for the technology sector (which will yield a high value) by a market beta for a technology company (which will also be high for the same reason) will result in double counting risk.[115]

Firm Characteristics

Earlier in this paper, we talked about the small firm premium and how it has been estimated using historical data, resulting in backward looking estimates with substantial standard error. We could use implied premiums to arrive at more forward looking estimates, using the following steps:

Step 1: Compute the implied equity risk premium for the overall market, using a broad index such as the S&P 500. Earlier in this paper, we estimated this, as of January 2014, to be 4.96%.

Step 2: Compute the implied equity risk premium for an index containing primarily or only small cap firms, such as the S&P 600 Small Cap Index. On January 1, 2014, the index was trading at 664.46, with an aggregated FCFE yield of about 3.34% (yielding a FCFE for the most recent year of 22.16), and an expected growth rate in earnings of 9.07% for the next 5 years. Using these values, in conjunction with the prevailing riskfree rate of 3.04%, yields the following equation:

$$664.96 = \frac{24.17}{(1+r)} + \frac{26.36}{(1+r)^2} + \frac{28.75}{(1+r)^3} + \frac{31.36}{(1+r)^4} + \frac{34.21}{(1+r)^5} + \frac{34.21(1.0304)}{(r-.0304)(1+r)^5}$$

[115] You could estimate betas for technology companies against a technology index (rather than the market index) and use these betas with the implied equity risk premium for technology companies.

Solving for the expected return, we get:

Expected return on small cap stocks = 7.51%

Implied equity risk premium for small cap stocks = 7.51% -3.04% = 4.47%

Step 3: The forward-looking estimate of the small cap premium should be the difference between the implied premium for small cap stocks (in step 2) and the implied premium for the market (in step 1).

Small cap premium = 4.47% - 4.96% = -0.49%

With the numbers in January 2014, small caps are priced to generate an expected return that is lower than the rest of the market, thus putting into question the wisdom of using the 4.45% small cap premium in computing costs of equity.

This approach to estimating premiums can be extended to other variables. For instance, one of the issues that has challenged analysts in valuation is how to incorporate the illiquidity of an asset into its estimated value. While the conventional approach is to attach an illiquidity discount, an alternative is to adjust the discount rate upwards for illiquid assets. If we compute the implied equity risk premiums for stocks categorized by illiquidity, we may be able to come up with an appropriate adjustment. For instance, you could estimate the implied equity risk premium for the stocks that rank in the lowest decile in terms of illiquidity, defined as turnover ratio.[116] Comparing this value to the implied premium for the S&P 500 of 4.96% should yield an implied illiquidity risk premium. Adding this premium to the cost of equity for relatively illiquid investments will then discount the value of these investments for illiquidity.

2. Default Spread Based Equity Risk Premiums

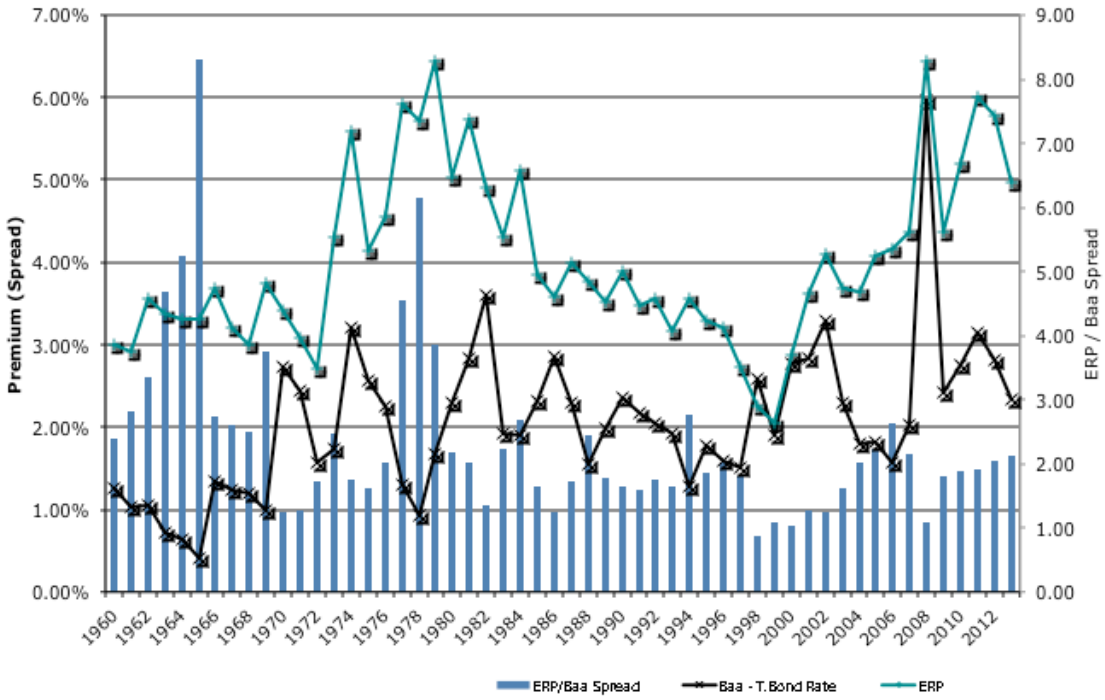
While we think of corporate bonds, stocks and real estate as different asset classes, it can be argued that they are all risky assets and that they should therefore be priced consistently. Put another way, there should be a relationship across the risk premiums in these asset classes that reflect their fundamental risk differences. In the corporate bond market, the default spread, i.e, the spread between the interest rate on corporate bonds and the treasury bond rate, is used as the risk premium. In the equity market, as we have seen through this paper, historical and implied equity premiums have tussled for supremacy as the measure of the equity risk premium. In the real estate market, no mention is made of an explicit risk premium, but real estate valuations draw heavily on the "capitalization rate", which is the discount rate applied to a real estate

[116] The turnover ratio is obtained by dividing $ trading volume in a stock by its market capitalization at that time.

property's earnings to arrive at an estimate of value. The use of higher (lower) capitalization rates is the equivalent of demanding a higher (lower) risk premium.

Of these three premiums, the default spread is the less complex and the most widely accessible data item. If equity risk premiums could be stated in terms of the default spread on corporate bonds, the estimation of equity risk premiums would become immeasurably simpler. For instance, assume that the default spread on Baa rated corporate bonds, relative to the ten-year treasury bond, is 2.2% and that equity risk premiums are routinely twice as high as Baa bonds, the equity risk premium would be 4.4%. Is such a rule of thumb even feasible? To answer this question, we looked at implied equity risk premiums and Baa-rated corporate bond default spreads from 1960 to 2013 in Figure 16.

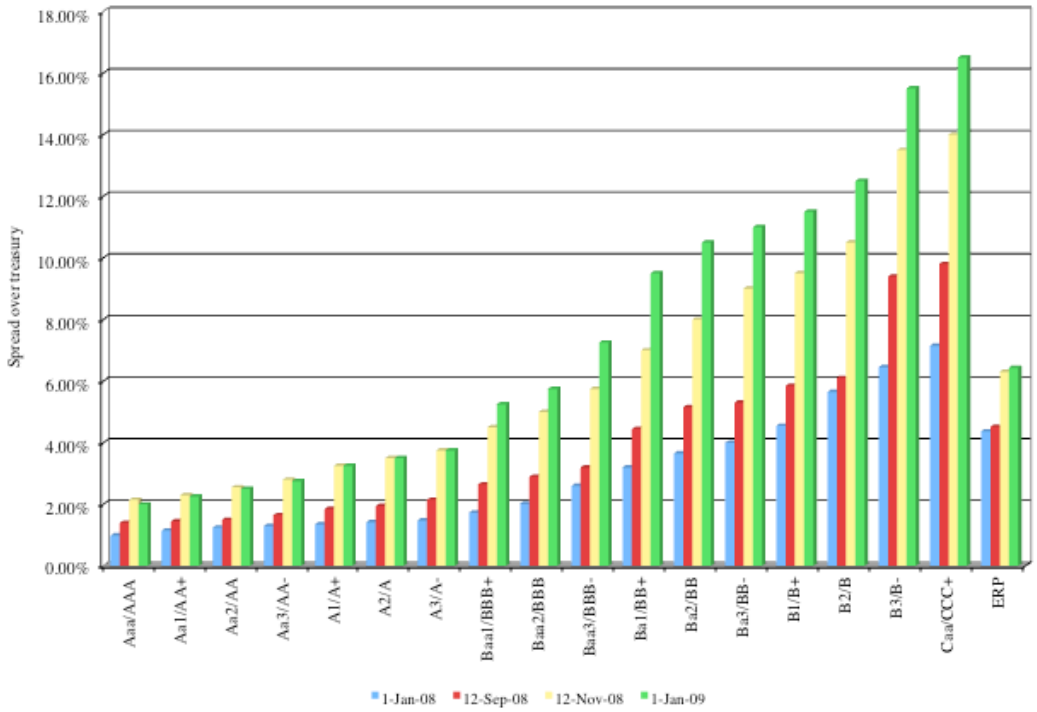
Figure 16: Equity Risk Premiums and Bond Default Spreads



Note that both default spreads and equity risk premiums jumped in 2008, with the former increasing more on a proportionate basis. The ratio of 1.08 (ERP/ Baa Default Spread) at the end of 2008 was close to the lowest value in the entire series, suggesting that either equity risk premiums were too low or default spreads were too high. At the end of 2013, both the equity risk premium and the default spread increased, and the ratio moved back to 2.12, a little higher than the median value of 2.02 for the entire time period. The connection between equity risk premiums and default spreads was most obvious during

2008, where changes in one often were accompanied by changes in the other. Figure 17 graphs out changes in default spreads and ERP over the tumultuous year:

Figure 17: Default Spreads on Ratings Classes



How could we use the historical relationship between equity risk premiums and default spreads to estimate a forward-looking equity risk premium? On January 1, 2014, the default spread on a Baa rated bond was 2.34%. Applying the median ratio of 2.02, estimated from 1960-2013 numbers, to the Baa default spread of 2.34% results in the following estimate of the ERP:

Default Spread on Baa bonds (over treasury) on 1/1/2014 = 2.34%

Imputed Equity Risk Premium = Default Spread * Median ratio or ERP/Spread

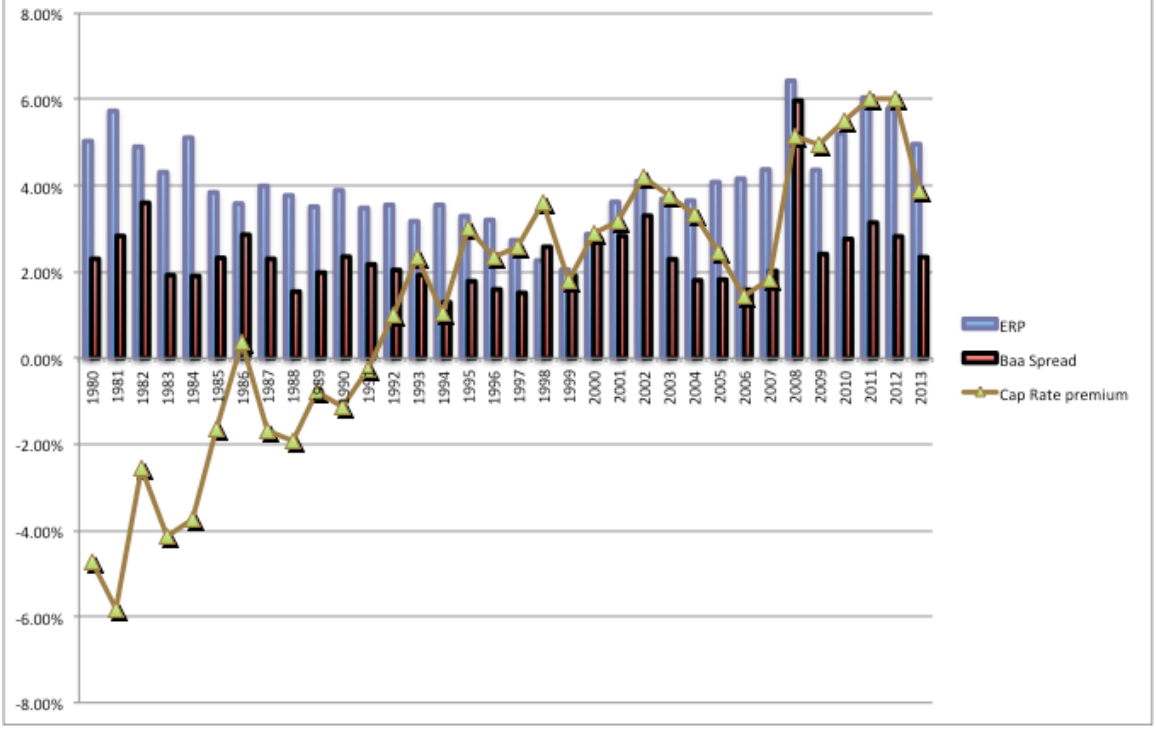
= 2.34%* 2.02 = 4.73%

This is a little lower than the implied equity risk premium of 4.96% that we computed in January 2014. Note that there is significant variation in the ratio (of ERP to default spreads) over time, with the ratio dropping below one at the peak of the dot.com boom (when equity risk premiums dropped to 2%) and rising to as high as 2.63 at the end of 2006; the standard error in the estimate is 0.20. Whenever the ratio has deviated significantly from the average, though, there is reversion back to that median over time.

The capitalization rate in real estate, as noted earlier, is a widely used number in the valuation of real estate properties. For instance, a capitalization rate of 10%, in conjunction with an office building that generates income of $ 10 million, would result in

a property value of $ 100 million ($10/.10). The difference between the capitalization ratio and the treasury bond rate can be considered a real estate market risk premium, In Figure 17, we used the capitalization rate in real estate ventures and compared the risk premiums imputed for real estate with both bond default spreads and implied equity risk premiums between 1980 and 2013.

Figure 17: Equity Risk Premiums, Cap Rates and Bond Spreads



The story in this graph is the convergence of the real estate and financial asset risk premiums. In the early 1980s, the real estate market seems to be operating in a different risk/return universe than financial assets, with the cap rates being less than the treasury bond rate. For instance, the cap rate in 1980 was 8.1%, well below the treasury bond rate of 12.8%, resulting in a negative risk premium for real estate. The risk premiums across the three markets - real estate, equity and bonds - starting moving closer to each other in the late 1980s and the trend accelerated in the 1990s. We would attribute at least some of this increased co-movement to the securitization of real estate in this period. In 2008, the three markets moved almost in lock step, as risk premiums in the markets rose and prices fell. The housing bubble of 2004-2008 is manifested in the drop in the real estate equity risk premium during those years, bottoming out at less than 2% at the 2006. The correction in housing prices since has pushed the premium back up. Both equity and bond premiums have adjusted quickly to pre-crisis levels in 2009 and 2010, and real estate premiums are following, albeit at a slower pace.

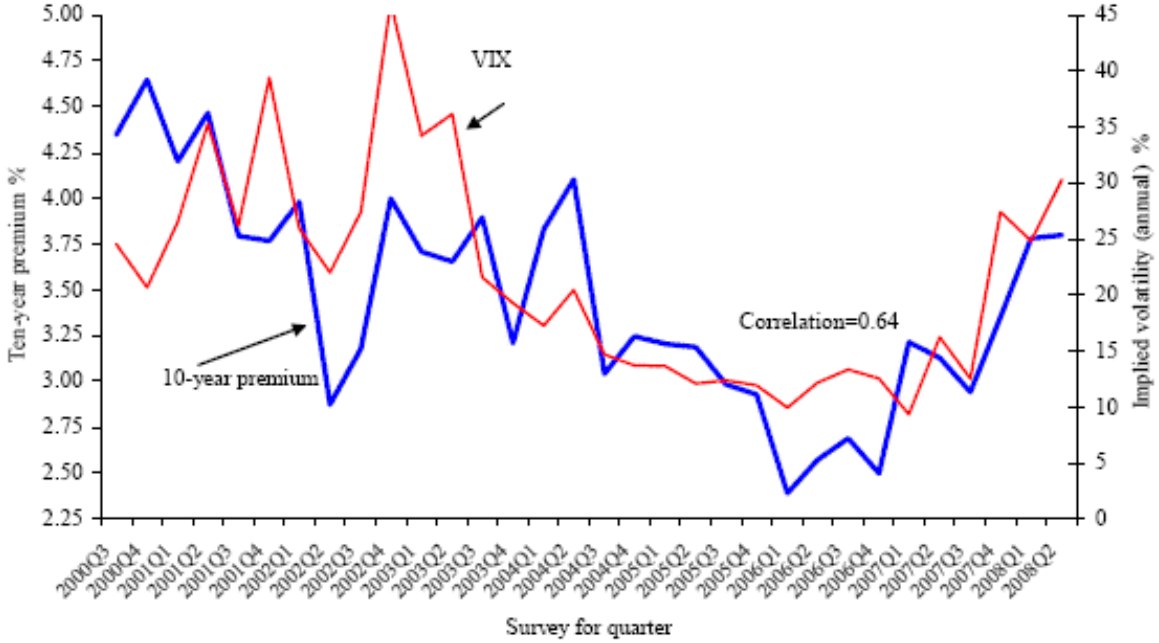
While the noise in the ratios (of ERP to default spreads and cap rates) is too high for us to develop a reliable rule of thumb, there is enough of a relationship here that we would suggest using this approach as a secondary one to test to see whether the equity risk premiums that we are using in practice make sense, given how risky assets are being priced in other markets. Thus, using an equity risk premium of 2%, when the Baa default spread is approximately at the same level strikes us as imprudent, given history. For macro strategists, there is a more activist way of using these premiums. When risk premiums in markets diverge, there is information in the relative pricing. Thus, the drop in equity risk premiums in the late 1990s, as default spreads stayed stable, would have signaled that the equity markets were overvalued (relative to bonds), just as the drop in default spreads between 2004 and 2007, while equity risk premiums were stagnant, would have suggested the opposite.

3. Option Pricing Model based Equity Risk Premium

There is one final approach to estimating equity risk premiums that draws on information in the option market. In particular, option prices can be used to back out implied volatility in the equity market. To the extent that the equity risk premium is our way of pricing in the risk of future stock price volatility, there should be a relationship between the two.

The simplest measure of volatility from the options market is the volatility index (VIX), which is a measure of 30—day volatility constructed using the implied volatilities in traded S&P 500 index options. The CFO survey premium from Graham and Harvey that we referenced earlier in the paper found a high degree of correlation between the premiums demanded by CFOs and the VIX value (see figure 18 below):

Figure 18: Volatility Index (VIX) and Survey Risk Premiums

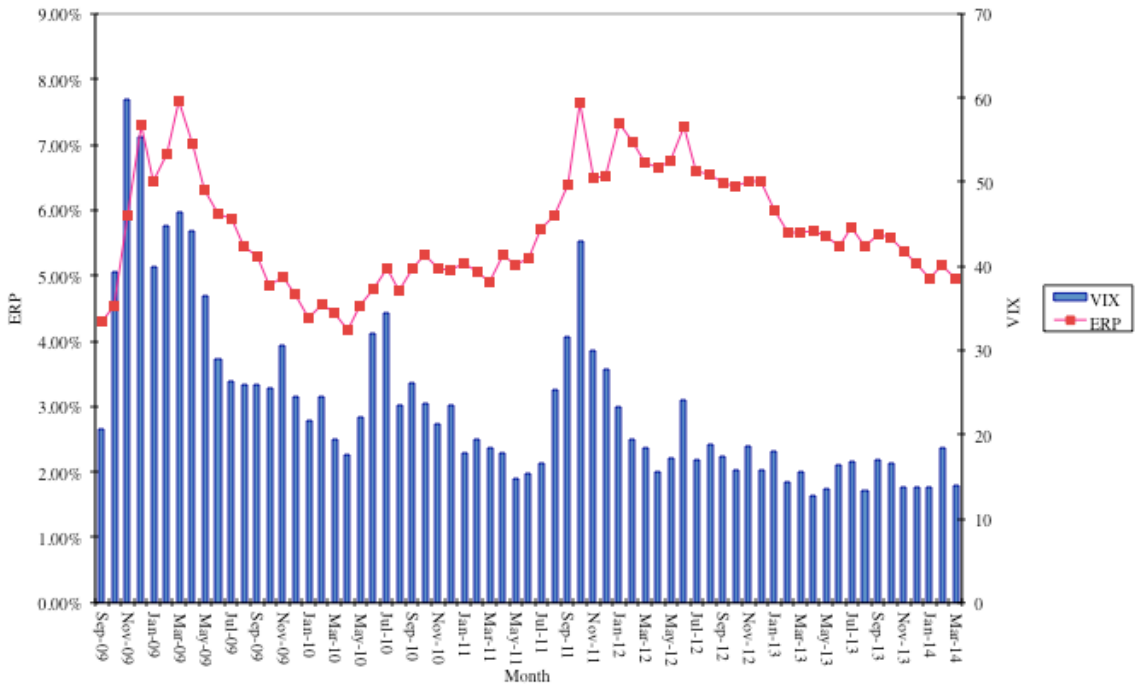


Santa-Clara and Yan (2006) use options on the S&P 500 to estimate the ex-ante risk assessed by investors from 1996 and 2002 and back out an implied equity risk premium on that basis.[117] To estimate the ex-ante risk, they allow for both continuous and discontinuous (or jump) risk in stocks, and use the option prices to estimate the probabilities of both types of risk. They then assume that investors share a specific utility function (power utility) and back out a risk premium that would compensate for this risk. Based on their estimates, investors should have demanded an equity risk premium of 11.8% for their perceived risk and that the perceived risk was about 70% higher than the realized risk over this period.

The link between equity market volatility and the equity risk premium also became clearer during the market meltdown in the last quarter of 2008. Earlier in the paper, we noted the dramatic shifts in the equity risk premiums, especially in the last year, as the financial crisis has unfolded. In Figure 19, we look at the implied equity risk premium each month from September 2008 to March 2014 and the volatility index (VIX) for the S&P 500:

[117] Santa-Clara, P. and S. Yan, 2006, *Crashes, Volatility, and the Equity Premium: Lessons from S&P 500 Options*, Review of Economics and Statistics, v92, pg 435-451.

Figure 19: ERP versus VIX



Note that the surge in equity risk premiums between September 2008 and December 2008 coincided with a jump in the volatility index and that both numbers have declined in the years since the crisis. The drop in the VIX between September 2011 and March 2012 was not accompanied by a decrease in the implied equity risk premium, but equity risk premiums have drifted down since.

In a paper referenced earlier, Bollerslev, Tauchen and Zhou (2009) take a different tack and argue that it is not the implied volatility per se, but the variance risk, i.e., the difference between the implied variance (in option prices) and the actual variance, that drives expected equity returns.[118] Thus, if the realized variance in a period is far higher (lower) than the implied variance, you should expect to see higher (lower) equity risk premiums demanded for subsequent periods. While they find evidence to back this proposition, they also note the relationship is strongest for short term returns (next quarter) and are weaker for longer-term returns. Bekaert and Hoerova (2013) decomposed the squared VIX into two components, a conditional variance of the stock market and an equity variance premium, and conclude that while the latter is a significant predictor of stock returns but the former is not.[119]

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[118] Bollerslev, T. G. Tauchen and H. Zhou, 2009, *Expected Stock Returns and Variance Risk Premia*, Review of Financial Studies, v22, 4463-4492.

[119] Bekaert, G. and M. Hoerova, 2013, *The VIX, Variance Premium and Stock Market Volatility*, SSRN Working Paper, http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2342200.

Choosing an Equity Risk Premium

We have looked at three different approaches to estimating risk premiums, the survey approach, where the answer seems to depend on who you ask and what you ask them, the historical premium approach, with wildly different results depending on how you slice and dice historical data and the implied premium approach, where the final number is a function of the model you use and the assumptions you make about the future. Ultimately, thought, we have to choose a number to use in analysis and that number has consequences. In this section, we consider why the approaches give you different numbers and a pathway to use to devise which number is best for you.

Why do the approaches yield different values?

The different ways of estimating equity risk premium provide cover for analysts by providing justification for almost any number they choose to use in practice. No matter what the premium used by an analyst, whether it be 3% or 12%, there is back-up evidence offered that the premium is appropriate. While this may suffice as a legal defense, it does not pass muster on common sense grounds since not all risk premiums are equally justifiable. To provide a measure of how the numbers vary, the values that we have attached to the US equity risk premium, using different approaches, in January 2013 are summarized in table 23.

Table 23: Equity Risk Premium (ERP) for the United States – January 2013

Approach Used	*ERP*	*Additional information*
Survey: CFOs	3.83%	Campbell and Harvey survey of CFOs (2013); Average estimate. Median was 3.4%.
Survey: Global Fund Managers	4.60%	Merrill Lynch (January 2014) survey of global managers
Historical - US	4.62%	Geometric average - Stocks over T.Bonds: 1928-2013
Historical – Multiple Equity Markets	3.30%	Average premium across 20 markets from 1900-2013: Dimson, Marsh and Staunton (2014)
Current Implied premium	4.96%	From S&P 500 – January 1, 2014
Average Implied premium	4.04%	Average of implied equity risk premium: 1960-2013
Implied premium adjusted for T.Bond rate and term structure	3.78%	Using regression of implied premium on T.Bond rate
Default spread based premium	4.72%	Baa Default Spread * Median value of (ERP/ Default Spread)

The equity risk premiums, using the different approaches, yield a range, with the lowest value being 3.30% and the highest being 4.96%. Note that the range would have been larger if we used other measures of historical risk premiums: different time periods, arithmetic instead of geometric averages.

There are several reasons why the approaches yield different answers much of time and why they converge sometimes.

1. When stock prices enter an extended phase of upward (downward) movement, the historical risk premium will climb (drop) to reflect past returns. Implied premiums will tend to move in the opposite direction, since higher (lower) stock prices generally translate into lower (higher) premiums. In 1999, for instance, after the technology induced stock price boom of the 1990s, the implied premium was 2% but the historical risk premium was almost 6%.
2. Survey premiums reflect historical data more than expectations. When stocks are going up, investors tend to become more optimistic about future returns and survey premiums reflect this optimism. In fact, the evidence that human beings overweight recent history (when making judgments) and overreact to information can lead to survey premiums overshooting historical premiums in both good and bad times. In good times, survey premiums are even higher than historical premiums, which, in turn, are higher than implied premiums; in bad times, the reverse occurs.
3. When the fundamentals of a market change, either because the economy becomes more volatile or investors get more risk averse, historical risk premiums will not change but implied premiums will. Shocks to the market are likely to cause the two numbers to deviate. After the terrorist attack on the World Trade Center in September 2001, for instance, implied equity risk premiums jumped almost 0.50% but historical premiums were unchanged (at least until the next update).

In summary, we should not be surprised to see large differences in equity risk premiums as we move from one approach to another, and even within an approach, as we change estimation parameters.

Which approach is the "best" approach?

If the approaches yield different numbers for the equity risk premium, and we have to choose one of these numbers, how do we decide which one is the "best" estimate? The answer to this question will depend upon several factors:

a. Predictive Power: In corporate finance and valuation, what we ultimately care about is the equity risk premium for the future. Consequently, the approach that has the best

predictive power, i.e. yields forecasts of the risk premium that are closer to realized premiums, should be given more weight. So, which of the approaches does best on this count?

Campbell and Shiller (1988) suggested that the dividend yield, a simplistic measure of the implied equity risk premium, had significant predictive power for future returns.[120] However, Goyal and Welch (2007) examined many of the measures suggested as predictors of the equity risk premium in the literature, including the dividend yield and the earnings to price ratio, and find them all wanting.[121] Using data from 1926 to 2005, they conclude that while the measures do reasonably well in sample, they perform poorly out of sample, suggesting that the relationships in the literature are either spurious or unstable. Campbell and Thompson (2008) disagree, noting that putting simple restrictions on the predictive regressions improve out of sample performance for many predictive variables.[122]

To answer this question, we looked at the implied equity risk premiums from 1960 to 2013 and considered four predictors of this premium – the historical risk premium through the end of the prior year, the implied equity risk premium at the end of the prior year, the average implied equity risk premium over the previous five years and the premium implied by the Baa default spread. Since the survey data does not go back very far, we could not test the efficacy of the survey premium. Our results are summarized in table 24:

Table 24: Predictive Power of different estimates- 1960 - 2013

Predictor	*Correlation with implied premium next year*	*Correlation with actual risk premium- next 5 years*	*Correlation with actual risk premium – next 10 years*
Current implied premium	0.757	0.638	0.421
Average implied premium: Last 5 years	0.655	0.424	0.339
Historical Premium	-0.278	-0.267	-0.482

[120] Campbell, J. Y. and R. J. Shiller. 1988, *The Dividend-Price Ratio And Expectations Of Future Dividends And Discount Factors*, Review of Financial Studies, v1(3), 195-228.

[121] Goyal, A. and I. Welch, 2007, *A Comprehensive Look at the Empirical Performance of Equity Premium Prediction,* Review of Financial Studies, v21, 1455-1508.

[122] Campbell, J.Y., and S.B. Thompson, 2008, *Predictive Excess Stock Returns Out of Sample: Can Anything Beat the Historical Average?* Review of Financial Studies, v21, 150-9-1531.

Default Spread based premium	0.111	0.328	0.171

Over this period, the implied equity risk premium at the end of the prior period was the best predictor of the implied equity risk premium in the next period, whereas historical risk premiums did worst. If we extend our analysis to make forecasts of the actual return premium earned by stocks over bonds for the next five or ten years, the current implied equity risk premium still yields the best forecast for the future, though default spread based premiums improve as predictors. Historical risk premiums perform even worse as forecasts of actual risk premiums over the next 5 or 10 years. If predictive power were the only test, historical premiums clearly fail the test.

b. Beliefs about markets: Implicit in the use of each approach are assumptions about market efficiency or lack thereof. If you believe that markets are efficient in the aggregate, or at least that you cannot forecast the direction of overall market movements, the current implied equity premium is the most logical choice, since it is estimated from the current level of the index. If you believe that markets, in the aggregate, can be significantly overvalued or undervalued, the historical risk premium or the average implied equity risk premium over long periods becomes a better choice. If you have absolutely no faith in markets, survey premiums will be the choice.

c. Purpose of the analysis: Notwithstanding your beliefs about market efficiency, the task for which you are using equity risk premiums may determine the right risk premium to use. In acquisition valuations and equity research, for instance, you are asked to assess the value of an individual company and not take a view on the level of the overall market. This will require you to use the current implied equity risk premium, since using any other number will bring your market views into the valuation. To see why, assume that the current implied premium is 4% and you decide to use a historical premium of 6% in your company valuation. Odds are that you will find the company to be over valued, but a big reason for your conclusion is that you started off with the assumption that the market itself is over valued by about 25-30%.[123] To make yourself market neutral, you will have to stick with the current implied premium. In corporate finance, where the equity risk premium is used to come up with a cost of capital, which in turn determines the long-term investments of

[123] If the current implied premium is 4%, using a 6% premium on the market will reduce the value of the index by about 25-30%.

the company, it may be more prudent to build in a long-term average (historical or implied) premium.

In conclusion, there is no one approach to estimating equity risk premiums that will work for all analyses. If predictive power is critical or if market neutrality is a pre-requisite, the current implied equity risk premium is the best choice. For those more skeptical about markets, the choices are broader, with the average implied equity risk premium over a long time period having the strongest predictive power. Historical risk premiums are very poor predictors of both short-term movements in implied premiums or long-term returns on stocks.

As a final note, there are papers that report consensus premiums, often estimated by averaging across approaches. I remain skeptical about these estimates, since the approaches vary not only in terms of accuracy and predictive power but also in their philosophy. Averaging a historical risk premium with an implied premium may give an analyst a false sense of security but it really makes no sense since they represent different views of the world and push in different directions.

Five myths about equity risk premiums

There are widely held misconceptions about equity risk premiums that we would like to dispel in this section.

1. Services "know" the risk premium: When Ibbotson and Sinquefield put together the first database of historical returns on stocks, bonds and bills in the 1970s, the data that they used was unique and not easily replicable, even for professional money managers. The niche they created, based on proprietary data, has led some to believe that Ibbotson Associates, and data services like them, have the capacity to read the historical data better than the rest of us, and therefore come up with better estimates. Now that the access to data has been democratized, and we face a much more even playing field, there is no reason to believe that any service has an advantage over any other, when it comes to historical premiums. Analysts should no longer be allowed to hide behind the defense that the equity risk premiums they use come from a reputable service and are thus beyond questioning.
2. There is no right risk premium: The flip side of the "services know it best" argument is that the data is so noisy that no one knows what the right risk premium is, and that any risk premium within a wide range is therefore defensible. As we have noted in this paper, it is indeed possible to arrive at outlandishly high or low premiums, but only if you use estimation approaches that do not hold up to scrutiny. The arithmetic

average premium from 2004 to 2013 for stocks over treasury bonds of 3% is an equity risk premium estimate, but it is not a good one.

3. The equity risk premium does not change much over time: Equity risk premiums reflect both economic fundamentals and investor risk aversion and they do change over time, sometimes over very short intervals, as evidenced by what happened in the last quarter of 2008. Shocks to the system – a collapse of a large company or sovereign entity or a terrorist attack – can cause premiums to shoot up overnight. A failure to recognize this reality will lead to analyses that lag reality.
4. Using the same premium is more important than using the right premium: Within many investment banks, corporations and consulting firms, the view seems to be that getting all analysts to use the same number as the risk premium is more important than testing to see whether that number makes sense. Thus, if all equity research analysts use 5% as the equity risk premium, the argument is that they are all being consistent. There are two problems with this argument. The first is that using a premium that is too high or low will lead to systematic errors in valuation. For instance, using a 5% risk premium across the board, when the implied premium is 4%, will lead you to find that most stocks are overvalued. . The second is that the impact of using too high a premium can vary across stocks, with growth stocks being affected more negatively than mature companies. A portfolio manager who followed the recommendations of these analysts would then be over invested in mature companies and under invested in growth companies.
5. If you adjust the cash flows for risk, there is no need for a risk premium: While statement is technically correct, adjusting cash flows for risk has to go beyond reflecting the likelihood of negative scenarios in the expected cash flow. The risk adjustment to expected cash flows to make them certainty equivalent cash flows requires us to answer exactly the same questions that we deal with when adjusting discount rates for risk.

Summary

The risk premium is a fundamental and critical component in portfolio management, corporate finance and valuation. Given its importance, it is surprising that more attention has not been paid in practical terms to estimation issues. In this paper, we began by looking at the determinants of equity risk premiums including macro economic volatility, investor risk aversion and behavioral components. We then looked at the three basic approaches used to estimate equity risk premiums – the survey approach, where

investors or managers are asked to provide estimates of the equity risk premium for the future, the historical return approach, where the premium is based upon how well equities have done in the past and the implied approach, where we use future cash flows or observed bond default spreads to estimate the current equity risk premium.

The premiums we estimate can vary widely across approaches, and we considered two questions towards the end of the paper. The first is why the numbers vary across approaches and the second is how to choose the "right" number to use in analysis. For the latter question, we argued that the choice of a premium will depend upon the forecast period, whether your believe markets are efficient and whether you are required to be market neutral in your analysis.

Appendix 1: Historical Returns on Stocks, Bonds and Bills – United States

Year	*Stocks*	*T.Bills*	*T.Bonds*	*Stocks - T. Bills*	*Stocks - T.Bonds*	*Arithmetic Average: Stocks versus T. Bonds*	*Geometric average: Stocks vs T.Bonds*
1928	43.81%	3.08%	0.84%	40.73%	42.98%	42.98%	42.98%
1929	-8.30%	3.16%	4.20%	-11.46%	-12.50%	15.24%	12.33%
1930	-25.12%	4.55%	4.54%	-29.67%	-29.66%	0.27%	-3.60%
1931	-43.84%	2.31%	-2.56%	-46.15%	-41.28%	-10.12%	-15.42%
1932	-8.64%	1.07%	8.79%	-9.71%	-17.43%	-11.58%	-15.81%
1933	49.98%	0.96%	1.86%	49.02%	48.13%	-1.63%	-7.36%
1934	-1.19%	0.32%	7.96%	-1.51%	-9.15%	-2.70%	-7.61%
1935	46.74%	0.18%	4.47%	46.57%	42.27%	2.92%	-2.49%
1936	31.94%	0.17%	5.02%	31.77%	26.93%	5.59%	0.40%
1937	-35.34%	0.30%	1.38%	-35.64%	-36.72%	1.36%	-4.22%
1938	29.28%	0.08%	4.21%	29.21%	25.07%	3.51%	-1.87%
1939	-1.10%	0.04%	4.41%	-1.14%	-5.51%	2.76%	-2.17%
1940	-10.67%	0.03%	5.40%	-10.70%	-16.08%	1.31%	-3.30%
1941	-12.77%	0.08%	-2.02%	-12.85%	-10.75%	0.45%	-3.88%
1942	19.17%	0.34%	2.29%	18.84%	16.88%	1.54%	-2.61%
1943	25.06%	0.38%	2.49%	24.68%	22.57%	2.86%	-1.18%
1944	19.03%	0.38%	2.58%	18.65%	16.45%	3.66%	-0.21%
1945	35.82%	0.38%	3.80%	35.44%	32.02%	5.23%	1.35%
1946	-8.43%	0.38%	3.13%	-8.81%	-11.56%	4.35%	0.63%
1947	5.20%	0.57%	0.92%	4.63%	4.28%	4.35%	0.81%
1948	5.70%	1.02%	1.95%	4.68%	3.75%	4.32%	0.95%
1949	18.30%	1.10%	4.66%	17.20%	13.64%	4.74%	1.49%
1950	30.81%	1.17%	0.43%	29.63%	30.38%	5.86%	2.63%
1951	23.68%	1.48%	-0.30%	22.20%	23.97%	6.61%	3.46%
1952	18.15%	1.67%	2.27%	16.48%	15.88%	6.98%	3.94%
1953	-1.21%	1.89%	4.14%	-3.10%	-5.35%	6.51%	3.57%
1954	52.56%	0.96%	3.29%	51.60%	49.27%	8.09%	4.98%
1955	32.60%	1.66%	-1.34%	30.94%	33.93%	9.01%	5.93%
1956	7.44%	2.56%	-2.26%	4.88%	9.70%	9.04%	6.07%
1957	-10.46%	3.23%	6.80%	-13.69%	-17.25%	8.16%	5.23%
1958	43.72%	1.78%	-2.10%	41.94%	45.82%	9.38%	6.39%
1959	12.06%	3.26%	-2.65%	8.80%	14.70%	9.54%	6.66%
1960	0.34%	3.05%	11.64%	-2.71%	-11.30%	8.91%	6.11%
1961	26.64%	2.27%	2.06%	24.37%	24.58%	9.37%	6.62%
1962	-8.81%	2.78%	5.69%	-11.59%	-14.51%	8.69%	5.97%
1963	22.61%	3.11%	1.68%	19.50%	20.93%	9.03%	6.36%
1964	16.42%	3.51%	3.73%	12.91%	12.69%	9.13%	6.53%
1965	12.40%	3.90%	0.72%	8.50%	11.68%	9.20%	6.66%

Year	*Stocks*	*T.Bills*	*T.Bonds*	*Stocks - T. Bills*	*Stocks - T.Bonds*	*Arithmetic Average: Stocks versus T. Bonds*	*Geometric average: Stocks vs T.Bonds*
1966	-9.97%	4.84%	2.91%	-14.81%	-12.88%	8.63%	6.11%
1967	23.80%	4.33%	-1.58%	19.47%	25.38%	9.05%	6.57%
1968	10.81%	5.26%	3.27%	5.55%	7.54%	9.01%	6.60%
1969	-8.24%	6.56%	-5.01%	-14.80%	-3.23%	8.72%	6.33%
1970	3.56%	6.69%	16.75%	-3.12%	-13.19%	8.21%	5.90%
1971	14.22%	4.54%	9.79%	9.68%	4.43%	8.12%	5.87%
1972	18.76%	3.95%	2.82%	14.80%	15.94%	8.30%	6.08%
1973	-14.31%	6.73%	3.66%	-21.03%	-17.97%	7.73%	5.50%
1974	-25.90%	7.78%	1.99%	-33.68%	-27.89%	6.97%	4.64%
1975	37.00%	5.99%	3.61%	31.01%	33.39%	7.52%	5.17%
1976	23.83%	4.97%	15.98%	18.86%	7.85%	7.53%	5.22%
1977	-6.98%	5.13%	1.29%	-12.11%	-8.27%	7.21%	4.93%
1978	6.51%	6.93%	-0.78%	-0.42%	7.29%	7.21%	4.97%
1979	18.52%	9.94%	0.67%	8.58%	17.85%	7.42%	5.21%
1980	31.74%	11.22%	-2.99%	20.52%	34.72%	7.93%	5.73%
1981	-4.70%	14.30%	8.20%	-19.00%	-12.90%	7.55%	5.37%
1982	20.42%	11.01%	32.81%	9.41%	-12.40%	7.18%	5.10%
1983	22.34%	8.45%	3.20%	13.89%	19.14%	7.40%	5.34%
1984	6.15%	9.61%	13.73%	-3.47%	-7.59%	7.13%	5.12%
1985	31.24%	7.49%	25.71%	23.75%	5.52%	7.11%	5.13%
1986	18.49%	6.04%	24.28%	12.46%	-5.79%	6.89%	4.97%
1987	5.81%	5.72%	-4.96%	0.09%	10.77%	6.95%	5.07%
1988	16.54%	6.45%	8.22%	10.09%	8.31%	6.98%	5.12%
1989	31.48%	8.11%	17.69%	23.37%	13.78%	7.08%	5.24%
1990	-3.06%	7.55%	6.24%	-10.61%	-9.30%	6.82%	5.00%
1991	30.23%	5.61%	15.00%	24.62%	15.23%	6.96%	5.14%
1992	7.49%	3.41%	9.36%	4.09%	-1.87%	6.82%	5.03%
1993	9.97%	2.98%	14.21%	6.98%	-4.24%	6.65%	4.90%
1994	1.33%	3.99%	-8.04%	-2.66%	9.36%	6.69%	4.97%
1995	37.20%	5.52%	23.48%	31.68%	13.71%	6.80%	5.08%
1996	23.82%	5.02%	1.43%	18.79%	22.39%	7.02%	5.32%
1997	31.86%	5.05%	9.94%	26.81%	21.92%	7.24%	5.53%
1998	28.34%	4.73%	14.92%	23.61%	13.42%	7.32%	5.63%
1999	20.89%	4.51%	-8.25%	16.38%	29.14%	7.63%	5.96%
2000	-9.03%	5.76%	16.66%	-14.79%	-25.69%	7.17%	5.51%
2001	-11.85%	3.67%	5.57%	-15.52%	-17.42%	6.84%	5.17%
2002	-21.97%	1.66%	15.12%	-23.62%	-37.08%	6.25%	4.53%
2003	28.36%	1.03%	0.38%	27.33%	27.98%	6.54%	4.82%
2004	10.74%	1.23%	4.49%	9.52%	6.25%	6.53%	4.84%

Year	*Stocks*	*T.Bills*	*T.Bonds*	*Stocks - T. Bills*	*Stocks - T.Bonds*	*Arithmetic Average: Stocks versus T. Bonds*	*Geometric average: Stocks vs T.Bonds*
2005	4.83%	3.01%	2.87%	1.82%	1.97%	6.47%	4.80%
2006	15.61%	4.68%	1.96%	10.94%	13.65%	6.57%	4.91%
2007	5.48%	4.64%	10.21%	0.84%	-4.73%	6.42%	4.79%
2008	-36.55%	1.59%	20.10%	-38.14%	-56.65%	5.65%	3.88%
2009	25.94%	0.14%	-11.12%	25.80%	37.05%	6.03%	4.29%
2010	14.82%	0.13%	8.46%	14.69%	6.36%	6.03%	4.31%
2011	2.10%	0.03%	16.04%	2.07%	-13.94%	5.79%	4.10%
2012	15.89%	0.05%	2.97%	15.84%	12.92%	5.88%	4.20%
2013	32.15%	0.07%	-9.10%	32.08%	41.25%	6.29%	4.62%

Appendix 2: Sovereign Ratings by Country- January 2014

Country	*FC*	*LC*	*Country*	*FC*	*LC*	*Country*	*FC*	*LC*
Abu Dhabi	Aa2	Aa2	Georgia	Ba3	Ba3	Oman	A1	A1
Albania	B1	B1	Germany	Aaa	Aaa	Pakistan	Caa1	Caa1
Angola	Ba3	Ba3	Ghana	B1	B1	Panama	Baa2	-
Argentina	B3	B3	Greece	Caa3	Caa3	Papua New Guinea	B1	B1
Armenia	Ba2	Ba2	Guatemala	Ba1	Ba1	Paraguay	Ba3	Ba3
Australia	Aaa	Aaa	Honduras	B2	B2	Peru	Baa2	Baa2
Austria	Aaa	Aaa	Hong Kong	Aa1	Aa1	Philippines	Baa3	Baa3
Azerbaijan	Baa3	Baa3	Hungary	Ba1	Ba1	Poland	A2	A2
Bahamas	Baa1	Baa1	Iceland	Baa3	Baa3	Portugal	Ba3	Ba3
Bahrain	Baa2	Baa2	India	Baa3	Baa3	Qatar	Aa2	Aa2
Bangladesh	Ba3	Ba3	Indonesia	Baa3	Baa3	Republic of the Congo	Ba3	Ba3
Barbados	Ba1	Ba1	Ireland	Ba1	Ba1	Romania	Baa3	Baa3
Belarus	B3	B3	Isle of Man	Aa1	Aa1	Russia	Baa1	Baa1
Belgium	Aa3	Aa3	Israel	A1	A1	Saudi Arabia	Aa3	Aa3
Belize	Caa2	Caa2	Italy	Baa2	Baa2	Senegal	B1	B1
Bermuda	Aa3	Aa3	Jamaica	Caa3	Caa3	Serbia	B1	B1
Bolivia	Ba3	Ba3	Japan	Aa3	Aa3	Singapore	Aaa	Aaa
Bosnia & Herzegovina	B3	B3	Jordan	B1	B1	Slovakia	A2	A2
Botswana	A2	A2	Kazakhstan	Baa2	Baa2	Slovenia	Ba1	Ba1
Brazil	Baa2	Baa2	Kenya	B1	B1	South Africa	Baa1	Baa1
Bulgaria	Baa2	Baa2	Korea	Aa3	Aa3	Spain	Baa3	Baa3
Cambodia	B2	B2	Kuwait	Aa2	Aa2	Sri Lanka	B1	-
Canada	Aaa	Aaa	Latvia	Baa2	Baa2	St. Maarten	Baa1	Baa1
Cayman Islands	Aa3	-	Lebanon	B1	B1	St. Vincent	B2	B2
Chile	Aa3	Aa3	Lithuania	Baa1	Baa1	Suriname	Ba3	Ba3
China	Aa3	Aa3	Luxembourg	Aaa	Aaa	Sweden	Aaa	Aaa
Colombia	Baa3	Baa3	Macao	Aa3	Aa3	Switzerland	Aaa	Aaa
Costa Rica	Baa3	Baa3	Malaysia	A3	A3	Taiwan	Aa3	Aa3
Croatia	Ba1	Ba1	Malta	A3	A3	Thailand	Baa1	Baa1
Cuba	Caa1	-	Mauritius	Baa1	Baa1	Trinidad and Tobago	Baa1	Baa1
Cyprus	Caa3	Caa3	Mexico	Baa1	Baa1	Tunisia	Ba3	Ba3
Czech Republic	A1	A1	Moldova	B3	B3	Turkey	Baa3	Baa3
DR of the Congo	B3	B3	Mongolia	B1	B1	Ukraine	Caa1	Caa1
Denmark	Aaa	Aaa	Montenegro	Ba3	-	United Arab Emirates	Aa2	Aa2
Dominican Republic	B1	B1	Morocco	Ba1	Ba1	United Kingdom	Aa1	Aa1
Ecuador	Caa1	-	Mozambique	B1	B1	United States of America	Aaa	Aaa
Egypt	Caa1	Caa1	Namibia	Baa3	Baa3	Uruguay	Baa3	Baa3
El Salvador	Ba3	-	Netherlands	Aaa	Aaa	Venezuela	Caa1	Caa1
Estonia	A1	A1	New Zealand	Aaa	Aaa	Vietnam	B2	B2
Fiji	B1	B1	Nicaragua	B3	B3	Zambia	B1	B1
Finland	Aaa	Aaa	Nigeria	Ba3	Ba3			
France	Aa1	Aa1	Norway	Aaa	Aaa			

Appendix 3: Country Risk Scores from the PRS Group – January 2014

PRS Score range	*Country*	*PRS Score range*	*Country*	*PRS Score range*	*Country*
<45	Somalia	65-67.5	Ghana	72.5-75	Costa Rica
	Syria		Greece		Uruguay
	Guinea		Indonesia		Kazakhstan
	Sudan		Moldova		China
50 -55	Zimbabwe		Honduras		Mexico
	Congo, DR		South Africa		Czech Republic
	Liberia		India		Israel
	Korea, DPR		Jordan		Malta
	Venezuela		Slovenia		Lithuania
55-60	Niger		Guatemala		Poland
	Uganda		Argentina	75-77.5	Azerbaijan
	Madagascar		Cuba		Bahamas
	Egypt		Cameroon		Ireland
	Haiti		Ecuador		Slovakia
	Lebanon		Thailand		United States
	Mozambique	67.5-70	Albania		United Kingdom
	Turkey		Mongolia		Belgium
	Ethiopia		Morocco		Chile
	Malawi		El Salvador		Trinidad & Tobago
60-62.5	Belarus		Romania	77.5-80	Botswana
	Papua New Guinea		Zambia		Malaysia
	Libya		Latvia		Australia
	Pakistan		Brazil		Austria
	CÃ´te dâ€™Ivoire		Colombia		Finland
	Togo		Paraguay		Iceland
	Kenya		Vietnam		Hong Kong
	Yemen		Dominican Republic	80-82.5	Netherlands
	Guinea-Bissau		Estonia		Saudi Arabia
	Guyana		Spain		Japan
	Myanmar		Croatia		Denmark
	Sri Lanka		Congo		Kuwait
62.5-65	Gambia	70-72.5	Bahrain		Oman
	Tunisia		Russia		Korea, South
	Armenia		Bulgaria		Qatar
	Iran		France		Canada
	Iraq		Italy	82.5-85	New Zealand
	Serbia		Portugal		Taiwan
	Bangladesh		Hungary		UAE
	Mali		Namibia		Sweden
	Tanzania		Peru	>85	Germany
	Sierra Leone		Angola		Luxembourg
	Jamaica		Bolivia		Brunei
	Senegal		Algeria		Singapore
	Cyprus		Philippines		Switzerland
	Nicaragua		Gabon		Norway
	Nigeria		Panama		
	Ukraine		Suriname		
	Burkina Faso				

Appendix 4: Equity Market volatility, relative to S&P 500: Total Equity Risk Premiums and Country Risk Premiums (Weekly returns from 2/12-2/14)

Country	*Standard deviation in Equities (weekly)*	*Relative Volatility (to US)*	*Total Equity Risk Premium*	*Country risk premium*
Argentina	29.64%	2.67	13.33%	8.33%
Bahrain	7.51%	0.68	3.38%	-1.62%
Bangladesh	18.35%	1.65	8.25%	3.25%
Bosnia	7.28%	0.65	3.27%	-1.73%
Botswana	4.62%	0.42	2.08%	-2.92%
Brazil	18.65%	1.68	8.39%	3.39%
Bulgaria	12.50%	1.12	5.62%	0.62%
Chile	13.50%	1.21	6.07%	1.07%
China	21.38%	1.92	9.61%	4.61%
Colombia	12.00%	1.08	5.40%	0.40%
Costa Rica	8.23%	0.74	3.70%	-1.30%
Croatia	9.57%	0.86	4.30%	-0.70%
Cyprus	54.97%	4.94	24.72%	19.72%
Czech Republic	14.32%	1.29	6.44%	1.44%
Egypt	23.42%	2.11	10.53%	5.53%
Estonia	10.00%	0.90	4.50%	-0.50%
Ghana	11.85%	1.07	5.33%	0.33%
Greece	36.61%	3.29	16.46%	11.46%
Hungary	15.51%	1.39	6.97%	1.97%
Iceland	11.21%	1.01	5.04%	0.04%
India	13.91%	1.25	6.25%	1.25%
Indonesia	16.75%	1.51	7.53%	2.53%
Ireland	12.95%	1.16	5.82%	0.82%
Israel	11.41%	1.03	5.13%	0.13%
Italy	21.50%	1.93	9.67%	4.67%
Jamaica	9.21%	0.83	4.14%	-0.86%
Jordan	10.24%	0.92	4.60%	-0.40%
Kazakhastan	22.33%	2.01	10.04%	5.04%
Kenya	11.55%	1.04	5.19%	0.19%
Korea	13.57%	1.22	6.10%	1.10%
Kuwait	7.94%	0.71	3.57%	-1.43%
Laos	16.23%	1.46	7.30%	2.30%
Latvia	10.66%	0.96	4.79%	-0.21%
Lebanon	6.19%	0.56	2.78%	-2.22%
Lithuania	8.60%	0.77	3.87%	-1.13%
Macedonia	12.11%	1.09	5.45%	0.45%
Malaysia	8.23%	0.74	3.70%	-1.30%
Malta	6.88%	0.62	3.09%	-1.91%

Mauritius	5.74%	0.52	2.58%	-2.42%
Mexico	14.01%	1.26	6.30%	1.30%
Mongolia	20.93%	1.88	9.41%	4.41%
Montenegro	13.93%	1.25	6.26%	1.26%
Morocco	10.70%	0.96	4.81%	-0.19%
Namibia	13.60%	1.22	6.12%	1.12%
Nigeria	15.06%	1.35	6.77%	1.77%
Oman	9.26%	0.83	4.16%	-0.84%
Pakistan	13.90%	1.25	6.25%	1.25%
Palestine	12.81%	1.15	5.76%	0.76%
Panama	6.29%	0.57	2.83%	-2.17%
Peru	16.63%	1.50	7.48%	2.48%
Philippines	16.73%	1.50	7.52%	2.52%
Poland	15.01%	1.35	6.75%	1.75%
Portugal	16.45%	1.48	7.40%	2.40%
Qatar	11.07%	1.00	4.98%	-0.02%
Romania	14.84%	1.33	6.67%	1.67%
Russia	16.39%	1.47	7.37%	2.37%
Saudi Arabia	11.76%	1.06	5.29%	0.29%
Serbia	9.05%	0.81	4.07%	-0.93%
Singapore	10.52%	0.95	4.73%	-0.27%
Slovakia	11.56%	1.04	5.20%	0.20%
Slovenia	17.83%	1.60	8.02%	3.02%
South Africa	12.40%	1.12	5.58%	0.58%
Spain	23.30%	2.10	10.48%	5.48%
Sri Lanka	13.72%	1.23	6.17%	1.17%
Taiwan	12.33%	1.11	5.54%	0.54%
Tanzania	11.16%	1.00	5.02%	0.02%
Thailand	18.40%	1.65	8.27%	3.27%
Tunisia	7.87%	0.71	3.54%	-1.46%
Turkey	24.07%	2.16	10.82%	5.82%
UAE	20.22%	1.82	9.09%	4.09%
Ukraine	30.90%	2.78	13.89%	8.89%
US	**11.12%**	**1.00**	**5.00%**	**0.00%**
Venezuela	40.03%	3.60	18.00%	13.00%
Vietnam	17.73%	1.59	7.97%	2.97%

Appendix 5: Equity Market Volatility versus Bond Market/CDS volatility

Standard deviation in equity index (σ_{Equity}) and government bond price (σ_{Bond}) was computed, using 100 trading weeks, where available. To compute the σ_{Yield}, we first computed the standard deviation of the bond yield in basis points and then divided by the level of the yield to get a coefficient of variation. To compute the σ_{CDS}, we first computed the standard deviation of the CDS in basis points and then divided by the level of the CDS to get a coefficient of variation.

Country	σ_{Equity}	σ_{Bond}	$\sigma_{Equity}/\sigma_{Bond}$	σ_{Yield}	$\sigma_{Equity}/\sigma_{Yield}$	σ_{CDS}	$\sigma_{Equity}/\sigma_{CDS}$
Argentina	29.64%	NA	NA		NA	5.20%	5.75
Brazil	18.65%	11.02%	1.69	10.75%	1.73	14.89%	1.40
Bulgaria	12.50%	NA	NA		NA	18.26%	0.87
Chile	13.50%	7.54%	1.79	30.66%	0.44	24.43%	0.80
China	21.38%	13.37%	1.60	37.87%	0.56	10.12%	2.21
Colombia	12.00%	5.73%	2.09	16.24%	0.74	19.87%	0.80
Costa Rica	8.23%	NA	NA		NA	10.91%	0.86
Croatia	9.57%	NA	NA		NA	7.24%	1.39
Czech Republic	14.32%	6.71%	2.13	32.15%	0.45	8.11%	1.85
Egypt	23.42%	NA	NA		NA	8.38%	2.88
Estonia	10.00%	NA	NA		NA	10.08%	1.09
Greece	36.61%	42.70%	0.86	37.84%	0.97	17.60%	2.26
Hungary	15.51%	12.15%	1.28	24.93%	0.62	11.72%	1.44
Iceland	11.21%	10.49%	1.07	18.29%	0.61	16.56%	0.84
India	13.91%	8.99%	1.55	8.74%	1.59	13.84%	1.14
Indonesia	16.75%	8.89%	1.88	22.68%	0.74	19.96%	1.04
Ireland	12.95%	5.11%	2.53	18.36%	0.71	21.79%	0.81
Israel	11.41%	NA	NA	NA	NA	18.25%	0.81
Italy	21.50%	6.89%	3.12	20.38%	1.05	14.46%	1.63
Kazakhastan	22.33%	NA	NA	NA	NA	16.72%	1.50
Korea	13.57%	5.17%	2.62	12.70%	1.07	11.69%	1.28
Laos	16.23%	NA	NA	NA	NA	23.10%	0.93
Lithuania	8.60%	NA	NA	NA	NA	19.16%	0.64
Malaysia	8.23%	6.15%	1.34	8.61%	0.96	28.46%	0.57
Mexico	14.01%	5.60%	2.50	12.12%	1.16	27.71%	0.78
Morocco	10.70%	NA	NA	NA	NA	14.48%	0.88
Pakistan	13.90%	7.59%	1.83	11.48%	1.21	7.09%	2.03
Panama	6.29%	NA	NA	NA	NA	22.11%	0.51
Peru	16.63%	9.61%	1.73	21.87%	0.76	18.66%	1.08
Philippines	16.73%	7.51%	2.23	28.48%	0.59	25.76%	0.91
Poland	15.01%	9.86%	1.52	29.21%	0.51	21.52%	0.91
Portugal	16.45%	13.75%	1.20	27.51%	0.60	13.73%	1.34
Romania	14.84%	8.31%	1.79	21.51%	0.69	12.74%	1.29
Russia	16.39%	8.10%	2.02	22.51%	0.73	17.89%	1.09

Saudi Arabia	11.76%	NA	NA	NA	NA	13.48%	1.01
Singapore	10.52%	4.43%	2.37	21.94%	0.48	NA	NA
Slovakia	11.56%	4.95%	2.34	25.66%	0.45	52.85%	0.75
Slovenia	17.83%	18.30%	0.97	35.61%	0.50	19.98%	1.09
South Africa	12.40%	9.74%	1.27	16.01%	0.77	15.59%	0.95
Spain	23.30%	5.04%	4.62	17.22%	1.35	18.63%	1.44
Thailand	18.40%	6.34%	2.90	19.89%	0.93	15.83%	1.32
Tunisia	7.87%	NA	NA	NA	NA	11.85%	0.78
Turkey	24.07%	7.83%	3.07	18.24%	1.32	16.59%	1.62
UAE	20.22%	NA	NA	NA	NA	6.01%	3.43
Ukraine	30.90%	22.29%	1.39	36.97%	0.84	9.48%	3.36
Venezuela	40.03%	25.32%	1.58	31.12%	1.29	3.62%	11.10
Vietnam	17.73%	NA	NA	NA	NA	11.29%	1.68
Average			*1.94*		*0.86*		*1.61*
Median			*1.79*		*0.75*		*1.09*

Appendix 6: Year-end Implied Equity Risk Premiums: 1961-2013

Year	*S&P 500*	*Earnings*[a]	*Dividends*[a]	*T.Bond Rate*	*Estimated Growth*	*Implied Premium*
1961	71.55	3.37	2.04	2.35%	2.41%	2.92%
1962	63.1	3.67	2.15	3.85%	4.05%	3.56%
1963	75.02	4.13	2.35	4.14%	4.96%	3.38%
1964	84.75	4.76	2.58	4.21%	5.13%	3.31%
1965	92.43	5.30	2.83	4.65%	5.46%	3.32%
1966	80.33	5.41	2.88	4.64%	4.19%	3.68%
1967	96.47	5.46	2.98	5.70%	5.25%	3.20%
1968	103.86	5.72	3.04	6.16%	5.32%	3.00%
1969	92.06	6.10	3.24	7.88%	7.55%	3.74%
1970	92.15	5.51	3.19	6.50%	4.78%	3.41%
1971	102.09	5.57	3.16	5.89%	4.57%	3.09%
1972	118.05	6.17	3.19	6.41%	5.21%	2.72%
1973	97.55	7.96	3.61	6.90%	8.30%	4.30%
1974	68.56	9.35	3.72	7.40%	6.42%	5.59%
1975	90.19	7.71	3.73	7.76%	5.99%	4.13%
1976	107.46	9.75	4.22	6.81%	8.19%	4.55%
1977	95.1	10.87	4.86	7.78%	9.52%	5.92%
1978	96.11	11.64	5.18	9.15%	8.48%	5.72%
1979	107.94	14.55	5.97	10.33%	11.70%	6.45%
1980	135.76	14.99	6.44	12.43%	11.01%	5.03%
1981	122.55	15.18	6.83	13.98%	11.42%	5.73%
1982	140.64	13.82	6.93	10.47%	7.96%	4.90%
1983	164.93	13.29	7.12	11.80%	9.09%	4.31%
1984	167.24	16.84	7.83	11.51%	11.02%	5.11%
1985	211.28	15.68	8.20	8.99%	6.75%	3.84%
1986	242.17	14.43	8.19	7.22%	6.96%	3.58%
1987	247.08	16.04	9.17	8.86%	8.58%	3.99%
1988	277.72	24.12	10.22	9.14%	7.67%	3.77%
1989	353.4	24.32	11.73	7.93%	7.46%	3.51%
1990	330.22	22.65	12.35	8.07%	7.19%	3.89%
1991	417.09	19.30	12.97	6.70%	7.81%	3.48%
1992	435.71	20.87	12.64	6.68%	9.83%	3.55%
1993	466.45	26.90	12.69	5.79%	8.00%	3.17%
1994	459.27	31.75	13.36	7.82%	7.17%	3.55%
1995	615.93	37.70	14.17	5.57%	6.50%	3.29%
1996	740.74	40.63	14.89	6.41%	7.92%	3.20%
1997	970.43	44.09	15.52	5.74%	8.00%	2.73%
1998	1229.23	44.27	16.20	4.65%	7.20%	2.26%
1999	1469.25	51.68	16.71	6.44%	12.50%	2.05%

2000	1320.28	56.13	16.27	5.11%	12.00%	2.87%
2001	1148.09	38.85	15.74	5.05%	10.30%	3.62%
2002	879.82	46.04	16.08	3.81%	8.00%	4.10%
2003	1111.91	54.69	17.88	4.25%	11.00%	3.69%
2004	1211.92	67.68	19.407	4.22%	8.50%	3.65%
2005	1248.29	76.45	22.38	4.39%	8.00%	4.08%
2006	1418.3	87.72	25.05	4.70%	12.50%	4.16%
2007	1468.36	82.54	27.73	4.02%	5.00%	4.37%
2008	903.25	65.39	28.05	2.21%	4.00%	6.43%
2009	1115.10	59.65	22.31	3.84%	7.20%	4.36%
2010	1257.64	83.66	23.12	3.29%	6.95%	5.20%
2011	1257.60	97.05	26.02	1.87%	7.18%	6.01%
2012	1426.19	102.47	30.44	1.76%	5.27%	5.78%
2013	1848.36	107.45	36.28	3.04%	4.28%	4.96%

[a] The earnings and dividend numbers for the S&P 500 represent the estimates that would have been available at the start of each of the years and thus may not match up to the actual numbers for the year. For instance, in January 2011, the estimated earnings for the S&P 500 index included actual earnings for three quarters of 2011 and the estimated earnings for the last quarter of 2011. The actual earnings for the last quarter would not have been available until March of 2011.

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Understanding Changes in Corporate Credit Spreads

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New evidence is reported on the empirical success of structural models in explaining changes in corporate credit risk. A parsimonious set of common factors and company-level fundamentals, inspired by structural models, was found to explain more than 54 percent (67 percent) of the variation in credit-spread changes for medium-grade (low-grade) bonds. No dominant latent factor was present in the unexplained variation. Although this set of factors had lower explanatory power among high-grade bonds, it did capture most of the systematic variation in credit-spread changes in that category. It also subsumed the explanatory power of the Fama and French factors among all grade classes.

We report our assessment of the empirical success of structural models in explaining changes in corporate credit spreads. We focus on the change in the credit spread, not its level.[1] The difference between studying spread levels and studying spread changes is equivalent to the difference between studying equity prices and studying equity excess returns. A one-to-one correspondence exists between the spread level and the bond price, whereas changes in credit spreads are directly associated with bond excess returns.[2] Therefore, credit-spread changes are the focus in bond pricing and, like expected equity returns in equity analysis, are the key to characterizing the risk–return trade-off in corporate bond markets, fixed-income portfolio allocation, credit-risk management, and credit-derivatives pricing.

So, what drives credit-spread changes? Early studies by Black and Scholes (1973) and Merton (1974) introduced "structural" models to explain corporate default risk and inspired the search for company-level and macro variables, such as stock volatility, company leverage, and interest rates, that could drive the changes in corporate credit spreads.

From among the various approaches to evaluating structural models (e.g., Eom, Helwege, and Huang 2004; Schaefer and Strebulaev 2004), we adopted the view that structural models are empirically successful in corporate bond pricing if they use variables that capture the variation in credit-spread changes. Using this approach, Collin-Dufresne, Goldstein, and Martin (2001; hereafter, CDGM) found that structural model variables explain less than 25 percent of the variation in credit-spread changes. The remaining unexplained variation, they found, is dominated by a strong latent factor. These findings pose a serious challenge to the empirical validity of structural models in explaining corporate credit-spread changes. Should we dismiss, or at least discount, the importance of structural models in empirical studies of credit-spread changes? As we will show, not necessarily.

Potential Determinants of Credit-Spread Changes

Our determinants of credit-spread changes were inspired by structural default-risk models, which view equity and debt as options on the company's value. In this contingent-claims framework, default occurs when the value of the company falls below a default threshold. Hence, variables governing company value affect default probabilities and recovery rates and, ultimately, drive credit spreads.

Whether structural models are empirically successful has long been an open question. One of the most popular and commercially successful systems for evaluating default risk, the Moody's KMV expected default frequency (EDF) methodology, as well as Moody's RiskCalc credit-scoring system, is based on the Merton (1974) model.[3] Yet, the academic literature is inconclusive regarding the performance of structural models. On the one hand,

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Jones, Mason, and Rosenfeld (1984) and Kim, Ramaswamy, and Sundaresan (1993) found that structural model variables explain only a small fraction of credit risk. Similarly, CDGM did not find structural models to be promising in identifying variables that adequately explain credit-spread changes. On the other hand, Campbell and Taksler (2003) documented strong comovement between aggregate bond spreads and aggregate idiosyncratic equity volatility. This evidence provides support for structural models because such models distinguish volatility as a key determinant of default probability.

We do not formally implement a structural model to evaluate a model's ability to fit prices or spreads. Instead, using a linear time-series regression, we assess how well structural model variables explain the variation in changes of corporate credit spreads. The model variables typically include interest rates, the slope of the term structure, equity market return and volatility, and company leverage and volatility. As well as previously studied variables, we incorporate company-level and aggregate idiosyncratic equity volatility and growth prospects and stock return momentum. The entire set of selected variables and how they relate to the probability of default and the recovery rate conditional on default are described in the following subsections.

■ *Idiosyncratic equity volatility*. The contingent-claims approach views debt as a combination of a risk-free loan and a short put option on the company. Higher volatility increases the option value, thereby decreasing bond prices and increasing spreads. Intuitively, higher volatility increases the likelihood of hitting the default threshold. Structural models posit that a company's value is driven by the company's total volatility, which has previously been proxied by equity market volatility. Following Campbell and Taksler (2003), we focus on idiosyncratic equity volatility. Campbell and Taksler documented a synchronous upward move in aggregate spreads and aggregate idiosyncratic volatility from 1990 to 2000. Furthermore, Campbell, Lettau, Malkiel, and Xu (2001) documented that both idiosyncratic and total volatility moved strongly upward in the past decade while market volatility remained constant.

Campbell and Taksler's (2003) findings link idiosyncratic equity volatility and credit-spread levels. Little is known, however, about how changes in idiosyncratic volatility affect credit-spread changes, which is why we explore it here.

■ *Stock return momentum*. Empirical research has extensively documented that the cross-section of equity returns is predictable from past returns over some horizons. Jegadeesh and Titman (1993) found momentum in stock prices; they showed that past "winners" continue to outperform past "losers" over the short-to-medium term. Thus, higher momentum in equity returns implies higher future company valuation and could imply lower probability of default and lower spreads.

The impact of momentum on credit-spread changes has not previously been documented, but Avramov, Chordia, Jostova, and Philipov (forthcoming 2007) establish a strong link between credit rating and momentum in equity returns. Given this new evidence, as well as the rich literature on the effect of momentum on future stock returns and its potential effect on the unobservable valuation process, momentum is a good candidate for inclusion in our analysis of credit-spread changes.

■ *Growth opportunities*. Improving prospects of company growth and profitability decrease the likelihood that the company's value will reach the default threshold. Our use of the price-to-book ratio (P/B) to proxy for future profitability was motivated by Pastor and Veronesi (2003), who offered a theoretical framework and empirical evidence that a company's P/B is linked to the level and volatility of expected profitability. Within the context of structural models, the new variables—momentum and P/B—affect underlying company value and, hence, the probability of default.

■ *Spot rate*. Longstaff and Schwartz (1995) argued that an increase in the spot rate increases company value (i.e., a higher reinvestment rate increases future value). This effect, in turn, lowers the probability that the value of the company's assets will fall below the default threshold. So, an increase in the spot rate reduces the credit-risk component in credit spreads and leads to tighter spreads. Longstaff and Schwartz empirically confirmed the negative relationship between spot rates and credit spreads.

■ *Term-structure slope*. We consider two competing hypotheses on the directional impact of changes in the term-structure slope on credit-spread changes. On the one hand, a steepening of the slope implies an increase in expected future spot rates, thereby reducing credit spreads. In addition, Fama and French (1989) argued that an increase in the yield-curve slope leads to an improving economy, improving recovery rates, and decreasing credit risk. On the other hand, the increase in expected future interest rates, which is implied by a steepening yield curve, may reduce the number of projects with positive net present value (NPV) available to the company. This reduction would, in turn, lower the company's valuation and increase spreads.

The realized impact of changes in the term-structure slope on credit-spread changes is an empirical question.

- *Leverage*. Merton (1974) implied that high leverage increases the probability of default because it raises the default threshold. As in CDGM, we used the company's equity return as a measure of change in the company's leverage. The use of this proxy is also justified by Welch (2004), who found that many proxies used in the literature play much less of a role than stock returns do in capturing changes in leverage.
- *Market conditions*. Changes in credit spreads are affected by changes in expected recovery rates, which affect payoffs to bondholders. Because the expected recovery rate is a function of the overall business climate (see, e.g., Altman and Kishore 1996), an improving economy should drive credit spreads down. We used equity market returns to proxy for changes in business climate, as was done by CDGM.
- *Fama–French factors*. Elton, Gruber, Agrawal, and Mann (2001) showed that the credit spread compensates for exposure to aggregate risk factors, namely, the Fama and French (1993) factors. For robustness and comparison, we studied the predictive power of the Fama–French factors in the presence of our proposed set of structural model variables.

Data

Our goal was to show that a parsimonious set of structural model variables can capture the time-series variation in individual bond credit-spread changes. We obtained bond and stock data from Datastream. Our sample includes all U.S. corporate bonds listed in Datastream that satisfied a set of selection criteria commonly used in the corporate bond literature. Extracting all U.S. corporate bonds from Datastream between September 1990 (the first available date for corporate bond spreads) and January 2003 yielded 8,892 bond issues. The bond and equity datasets were then matched by using each bond's unique identifier.

This initial sample was subjected to a number of filtering criteria. We excluded bonds with no corresponding equity data in Datastream. We removed all bonds with equity or derivative features (such as callable, puttable, and convertible bonds), bonds with warrants, and bonds with floating interest rates. We also excluded bonds with fewer than 25 consecutive monthly observations, as did CDGM. We removed all bonds for which the credit-spread data appeared to be problematic. For example, a bond record might have indicated a negative credit spread because of an incorrect U.S. Treasury yield-curve assignment. Finally, because extreme spreads can arise from data errors or credit-spread blowups, we removed individual credit-spread observations exceeding 13 percent (five standard deviations from the mean).[4]

The filtered sample contains 2,375 fixed-rate, straight U.S. corporate bonds issued by 678 companies. The average number of monthly credit-spread observations per bond is 47. Note that our dataset addresses potential survivorship bias issues because we have not excluded bonds that went bankrupt or expired.

Our data are similar in quality to data from Bloomberg and the Lehman Brothers database. Analysis of a subset of bonds from the three data sources revealed a close match in their prices. This similarity is not surprising because these databases have the same data providers (i.e., the large institutional dealers in the bond market). Datastream, however, covers a much larger cross-section of bonds. We verified that the size and liquidity (as measured by trading volume) of the part of our sample covered by other sources were similar to that of the part not covered by other databases.

For all selected bonds, we extracted all end-of-month credit spreads available in Datastream for the period September 1990 to January 2003. Datastream computes credit spreads as the yield differential between the bond and the Treasury curve, with maturity and compounding frequency taken into account:

$$Spread_{i,t} = Yield_{i,t} - Yield_{CURVE,t}, \quad (1)$$

where $Yield_{i,t}$ is the t-period yield on corporate bond i and $Yield_{CURVE,t}$ is the yield on a t-period T-bond.

Bond Sample. **Table 1** provides descriptive statistics for the entire sample of 2,375 corporate bonds and for low-, medium-, and high-credit-risk groups.[5] Table 1 reports that the average rating across the credit-risk groups declined from A (numeric average of 5.92) for the highest-grade group to a non-investment-grade BB– (numeric of 12.99) for the lowest-grade group.[6] Our high-credit-risk group contained mostly high-yield bonds, which have not been considered in previous studies of credit-spread changes.

Both credit spreads and their changes differ substantially among the credit-risk groups. As Table 1 shows, the volatility of spread levels (and changes) rises sharply with rising credit risk—from 0.33 percent (0.17 percent) to 2.02 percent (0.77 percent) a month. The mean credit-spread change also

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Table 1. Descriptive Statistics: Corporate Bond Sample, September 1990–January 2003

Statistic	All Bonds	Groups Based on Credit-Risk Level		
		Low	Medium	High
Credit spread (%)				
Mean (median)	2.46 (1.84)	0.80 (0.82)	1.88 (1.84)	4.69 (4.05)
Standard deviation	2.03	0.33	0.37	2.02
Range	0.00 to 12.99	0.00 to 1.32	1.32 to 2.63	2.63 to 12.99
Credit-spread change (%)				
Mean (median)	0.03 (0.01)	0.00 (0.00)	0.01 (0.01)	0.06 (0.05)
Standard deviation	0.52	0.17	0.23	0.77
Range	–10.02 to 11.81	–1.09 to 1.22	–1.25 to 1.20	–8.76 to 9.67
Duration (years)	5.16	4.90	5.95	4.35
Time to maturity (years)	8.69	8.20	10.44	7.19
Issue size ($ millions)	300	296	307	297
Trading volume ($ millions per month)	5.48	4.96	6.66	5.59
S&P average rating	8.58 (BBB)	5.92 (A)	8.29 (BBB+)	12.99 (BB-)

Notes: Trading volume was not available for all bonds; the figures represent trading volume per bond per month when data were available. Credit ratings were available for only some of the bonds. The last row reports the average letter S&P (Standard & Poor's) rating in parentheses. S&P ratings convert to numeric ratings as follows: AAA = 1, AA+ = 2, AA = 3, AA– = 4, . . ., D = 22. An S&P rating below BBB– is considered to be noninvestment grade.

differs substantially among the credit-risk groups. Duration, time to maturity, size, and trading volume are comparable across the credit-risk groups.

Aggregate Variables. Descriptive statistics for our marketwide measures for aggregate idiosyncratic equity volatility, aggregate P/B, and equity market return are reported in Panel A of **Table 2**. The marketwide measures were calculated as equally weighted averages across all 678 stocks in the sample.

Government rates in the study were represented by the monthly series of 2-, 5-, 10-, and 30-year Merrill Lynch government bond yield

Table 2. Descriptive Statistics: Independent Variables, September 1990–January 2003

Statistic	Mean	Median	Minimum	Maximum	Standard Deviation
A. Common factors					
Equity market return (%)	1.28	1.57	–17.09	11.07	4.34
Change in P/B (× 100)	0.50	2.21	–64.12	62.49	14.16
Change in idiosyncratic equity volatility (× 10; 000)	0.08	0.08	–19.75	20.42	3.97
Change in 5-year government rate (%)	–0.03	–0.05	–0.82	0.82	0.31
Change in term-structure slope (%)	0.00	0.00	–0.27	0.40	0.10
MKT factor (%)	0.55	1.10	–15.99	10.82	4.34
SMB factor (%)	0.12	–0.10	–11.60	14.62	3.43
HML factor (%)	0.08	0.05	–20.79	14.92	3.99
Fed cycle dummy (1 = expansion)	0.63	1.00	0.00	1.00	0.48
B. Company-level variables					
Stock return (%)	1.04	0.71	–28.01	33.10	9.73
Stock momentum (%)	1.97	1.68	–35.05	40.87	13.32
Change in idiosyncratic equity volatility (× 10; 000)	–0.01	–0.02	–28.72	27.77	5.76
Change in P/B (× 100)	0.16	0.50	–94.00	79.00	23.49

Note: Company-level numbers are cross-sectional medians for all companies.

indices. We used one index at a time in our regressions because changes in these indices are highly correlated; correlations range between 0.73 and 0.95. We selected the yield on the 5-year note as the spot rate because its maturity was close to the sample average.[7]

The term-structure slope is the yield differential between any two of the 2-, 5-, 10-, and 30-year Merrill Lynch indices. Except for equity market returns, we used changes, rather than levels, in the aggregate variables.

The factors from the Fama–French three-factor model are as follows: The MKT factor is the return on the market minus the return on the risk-free rate, the SMB factor is the return on the small-capitalization portfolio minus the return of the large-cap ("big") portfolio, and HML is the return on the portfolio of high book-to-market stocks minus the return on the portfolio of low book-to-market stocks.[8] (The row in Table 2 titled "Fed cycle dummy" is explained in the "Additional Robustness Tests" section.)

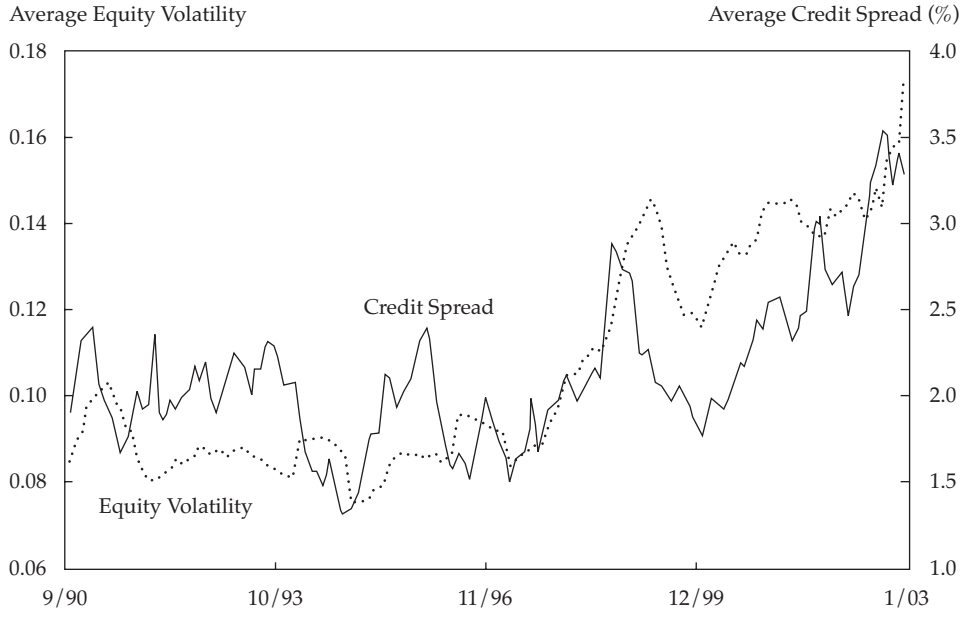
Company-Level Variables. Descriptive statistics for the company-level variables are presented in Panel B of Table 2. The company-level variables were based on each issuer's equity data. Monthly stock returns and P/Bs were obtained from Datastream. Following Brennan, Chordia, and Subrahmanyam (1998), we calculated stock return momentum as the cumulative return over the two months ending at the beginning of the previous month. This variable excludes the preceding month's return to avoid spurious association between prior and current returns because of thin trading or effects of the bid–ask spread.[9] Monthly volatilities were calculated as the sum of squared daily returns over the trading days of the month. Company-level idiosyncratic equity volatility was computed as the difference between monthly market volatility and monthly total company-level volatility, as in Campbell et al. (2001).

Because our analysis focuses on the determinants of changes in corporate credit spreads, we used changes in volatility and P/Bs. We considered the possibility that, because book values remain relatively unchanged from month to month, the change in the individual P/B would be highly collinear with the company stock return. We found, however, that the two variables have an average correlation coefficient of 0.18, which indicates that much of the information in the P/B is not captured by the stock return.

Results

We begin with an overview of credit spreads in the period 1990–2003. **Figure 1** displays the evolution of aggregate idiosyncratic equity volatility and average corporate credit spread in the 1990–2003 period. Figure 1 indicates that the synchronous upward trend previously documented by Campbell and Taksler (2003) for the late 1990s extended beyond their

Figure 1. Credit Spreads of U.S. Corporate Bonds and Idiosyncratic Equity Volatility, September 1990–January 2003



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sample period. A prominent spike in the spread levels is visible in 1998 during the major credit events of the Russian crisis and the follow-up collapse of Long-Term Capital Management. Another spike in 2002–2003 marks the record defaults of the burst in the telecom bubble. Similarly, the upward trend in idiosyncratic volatility peaks around the fall of 1998 and the end of 2002. This strong comovement supports Campbell and Taksler's suggestion that increasing corporate spreads may be driven by the increase in idiosyncratic volatility.

Figure 2 shows a strong negative comovement between the average credit spread and the five-year Treasury yield that is consistent with the theoretical predictions of structural default-risk models. The two series have a correlation of –0.83. The correlation between the changes in these series is about the same (–0.86), which suggests that increases in interest rates significantly reduce the default probability of a typical company.

Time-Series Determinants of Credit-Spread Changes. We first examined the time-series explanatory power of common factors and company-level attributes for all 2,375 corporate bonds in our sample. In the time-series analyses, we ran individual-bond regressions, then averaged the estimated coefficients across all bonds. The average values are reported. The *t*-statistics were computed from the cross-section of the individual regression coefficients.

To indicate the relative importance of each variable, we present in **Table 3** results of univariate regressions of credit-spread changes on individual common factors (in Panel A) and company-level variables (in Panel B). Panel A shows that credit-spread changes in our sample were significantly affected by all these structural model factors. Factor sensitivities are strongly significant and have the theoretically expected sign. Specifically, changes in government rates had the strongest impact on credit-spread changes in terms of both significance and explanatory power. Changes in the five-year spot rate alone explained 28.63 percent of the variation in individual credit-spread changes. Consistent with the theoretical implications of risk-neutral contingent-claims pricing, increasing spot rates led to decreasing credit spreads.

Equity market returns were the second-strongest (after the government rate) determinant of credit-risk changes. This factor explained 18.25 percent of the variation.

Changes in the term-structure slope were also important determinants of changes in corporate credit spreads. Changes in the long-term slope (30Y – 2Y; that is, changes between 30-year and 2-year yields) had a strong positive impact on credit-spread changes, which is consistent with the hypothesis that an increasing slope decreases the expected NPV of available projects and thus reduces company value and increases credit spreads. Changes between 30- and 10-year yields (30Y – 10Y) explained 17.7 percent (with the highest explanatory power of the slope factors) of individual spread changes. The high explanatory power of this slope

Figure 2. Treasury Yields vs. Corporate Credit Spreads, September 1990–January 2003

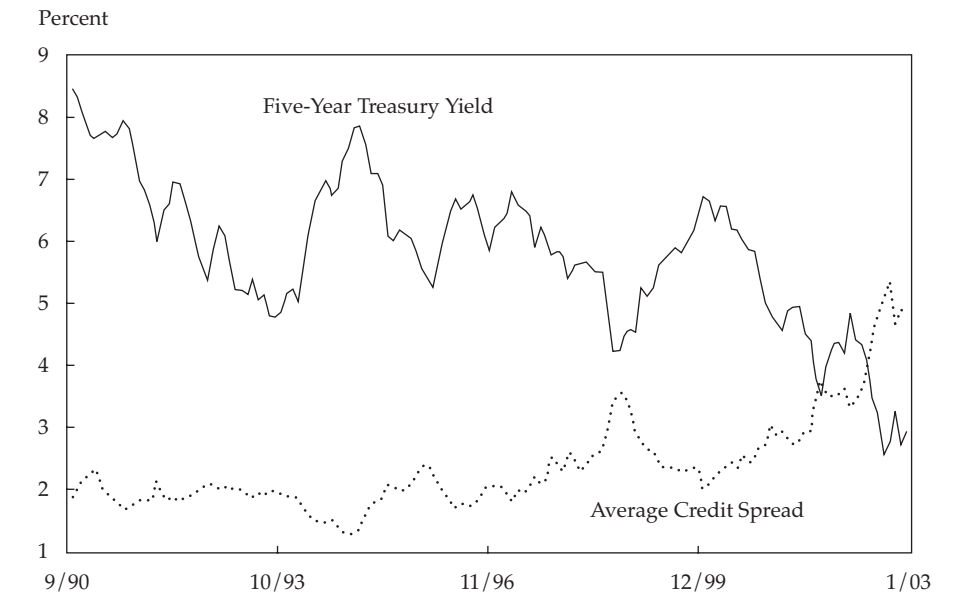

Table 3. Explanatory Power of Common Factors and Company-Level Characteristics, Data for September 1990–January 2003
(*t*-statistics in parentheses)

Factor	β_{ik}	Adjusted R^2
A. Common factors		
Equity market return	–3.22	18.25%
	(**–36.26**)	
Change in aggregate P/B	–0.89	3.21
	(**–34.88**)	
Change in aggregate idiosyncratic equity volatility	123.73	6.47
	(**32.25**)	
Spot rate		
2-Year (2Y)	–0.56	26.79
	(**–45.30**)	
5-Year (5Y)	–0.54	28.63
	(**–49.29**)	
10-Year (10Y)	–0.60	25.73
	(**–50.52**)	
30-Year (30Y)	–0.52	15.82
	(**–45.95**)	
Term-structure slope		
5Y – 2Y	–0.26	1.74
	(**–14.96**)	
10Y – 2Y	0.30	4.15
	(**17.58**)	
30Y – 2Y	0.48	11.49
	(**31.96**)	
30Y – 10Y	1.22	17.70
	(**42.60**)	
B. Company-level characteristics		
	β_i	Adjusted R^2
Stock return	–1.35	15.45%
	(–**22.17**)	
Stock momentum	–1.45	6.37
	(–1.70)	
Change in idiosyncratic equity volatility	263.52	13.20
	(**26.44**)	
Change in P/B	–0.52	7.29
	(–**14.46**)	

Note: Boldface indicates *t*-statistics that are significant at the 5 percent level.

could be a result of its correspondence to the period when refinancing needs (the average bond maturity is 8.69 years) of a typical company occur. In contrast, an increase in the short end of the term-structure slope (5Y – 2Y) reduced credit spreads, which is consistent with the hypothesis that an increasing slope implies an improving economy, which leads to a credit-risk decline.

In line with the findings of Campbell and Taksler (2003), changes in aggregate idiosyncratic volatility had a strong positive impact on credit-spread changes at the individual-bond level. Finally, an increase in the aggregate P/B, indicating improving growth opportunities, reduced credit spreads.

Panel B in Table 3 shows the relative importance of each company-level characteristic. These variables are all significant and have the theoretically expected sign. As posited by structural models, changes in company leverage (proxied by stock returns) and company-level idiosyncratic volatility are the most important drivers of credit-spread changes. Positive stock returns (a decrease in leverage) tend to decrease spreads significantly, whereas increases in stock volatility tend to increase them significantly. Bond spreads also responded to momentum in stock returns, but the *t*-statistic of –1.70 is significant only at the 10 percent level.[10] Finally, changes in the company's growth opportunities (measured by the P/B) reduced spreads and explained about 7.29 percent of the variation in credit-risk changes.

Next, we analyzed the joint explanatory power of all suggested variables in a series of regressions of the following type:

$$\Delta Spread_{it} = \alpha_i + \beta_{1i} F_t + \beta_{2i} C_{it} + e_{it}, \quad (2)$$

where F_t is the vector of common factors realized at time t, C_{it} is the vector of company-level characteristics at time t, and β_{1i} and β_{2i} are the vectors of sensitivities.

Table 4 presents the results of five specifications of regression Equation 2 and provides a clear picture of the relative power of the common and company-level variables in explaining credit-spread changes. In addition to the common factors previously explored, we added the Fama–French factors. Column M1 (for Model 1) shows only the combined explanatory power of five common factors: equity market return, changes in the aggregate P/B, aggregate idiosyncratic volatility, the (5-year) spot rate, and the term-structure slope measured by the yield differential between 30-year and 10-year Treasuries.[11] The R^2 indicates that these five factors captured as much as 43.78 percent of the time-series variation in credit-spread changes. Changes in the 5-year spot rate had the strongest impact on credit-spread changes, followed by changes in idiosyncratic volatility. All the aggregate variables except changes in the term-structure slope are significant.

Column M2 presents only the combined explanatory power of company-level variables plus lagged credit-spread changes to control for potential autocorrelation. The company-level

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Table 4. Total Explained Variation in Credit-Spread Changes, Data for September 1990–January 2003
(*t*-statistics in parentheses)

Variable	M1	M2	M3	M4	M5
A. Common factors					
Equity market return	–0.66	—	–0.05	—	—
	(**–6.98**)		(–0.59)		
Change in aggregate P/B	–0.10	—	–0.07	—	–0.11
	(**–4.63**)		(**–3.23**)		(**–4.30**)
Change in aggregate idiosyncratic equity volatility	58.13	—	27.46	—	15.11
	(**14.36**)		(**6.24**)		(**3.30**)
5-Year spot rate	–0.46	—	–0.45	—	–0.43
	(**–34.18**)	—	(**–33.70**)		(**–29.75**)
Term-structure slope (30Y – 10Y)	0.02	—	–0.07	—	0.07
	(0.70)	—	(**–2.19**)		(1.86)
MKT factor	—	—	—	–0.02	0.00
				(**–27.62**)	(1.27)
SMB factor	—	—	—	–0.01	0.00
				(**–19.77**)	(**4.14**)
HML factor	—	—	—	–0.03	0.00
				(**–22.00**)	(1.93)
B. Company-level characteristics					
$\Delta Spread_{i,t-1}$	—	–0.11	–0.06	—	–0.04
		(**–12.51**)	(**–7.95**)		(**–4.80**)
$\Delta Spread_{i,t-2}$	—	–0.06	–0.03	—	–0.05
		(**–8.68**)	(**–4.85**)		(**–7.27**)
Stock return	—	–0.77	–0.30	—	–0.25
		(**–17.69**)	(**–8.49**)		(**–6.20**)
Stock momentum	—	–0.28	–0.26	—	–0.18
		(**–10.36**)	(**–9.70**)		(**–5.60**)
Change in idiosyncratic equity volatility	—	129.15	49.83	—	84.05
		(**17.05**)	(**6.35**)		(**9.51**)
Change in P/B	—	–0.18	–0.01	—	–0.07
		(**–7.72**)	(–0.27)		(**–2.24**)
Adjusted R^2	43.78%	26.35%	53.44%	25.93%	54.72%

Note: Boldface indicates *t*-statistics that are significant at the 5 percent level.

attributes explained as much as 26.35 percent of the time-series variation of credit-spread changes. All the company characteristics are significant and have the expected sign. Changes in idiosyncratic volatility and stock returns are the most significant variables. These results attest to the importance of company fundamentals in explaining variations in corporate credit-spread changes.

Next, we combined the aggregate and company-level variables to assess their joint explanatory power. Column M3 shows that such variables captured as much as 53.44 percent of the variation in credit-spread changes. The company characteristic P/B lost significance when the aggregate P/B was included in the regression. Similarly, when the company stock return was included, the market return lost significance. All the remaining variables remained strongly significant in the all-inclusive regression. This evidence suggests that the credit-spread variation has both a systematic component captured by common factors and an idiosyncratic one captured by company-level variables.

Next, we added the three Fama–French factors to the parsimonious set of structural model determinants. The Fama–French factors have traditionally been used in equity pricing, but Elton et al. (2001) documented that these factors also capture systematic variation in credit spreads. Indeed, Column M4 shows that the Fama–French factors have a negative and significant impact on credit-spread changes, explaining, as a group, 25.93 percent of spread changes.

As Column M5 shows, including the Fama–French factors with our common and company-level variables (excluding equity market return because it is highly correlated with the MKT factor) increased the explanatory power only from 53.44 percent to 54.72 percent. Note in Column M5 that both MKT and HML lost significance in the presence of our suggested variables and that the SMB factor flipped signs.

Overall, the evidence suggests that our structural model factors capture essentially all the systematic variation in credit-spread changes and subsume the explanatory power of the Fama–French factors.

To summarize, the time-series regression results provide strong empirical support for structural models. Common factors alone explained about 44 percent of the time variation in individual credit-spread changes, and company-level attributes alone explained 26 percent. Common factors and company-level variables combined explained more than 53 percent of the variation in credit-spread changes, a substantial improvement over previous findings.

Credit-Spread Variation by Credit-Risk Group. The evidence thus far suggesting that aggregate variables and company-level variables explain a substantial part of the variation in individual credit-spread changes contradicts previous research. We show here that much of the sharp difference is attributable to the composition of bonds in our sample. Specifically, our sample has extensive coverage of high-yield bonds.

For further analysis, we divided our sample into three credit-risk groups and reestimated the M5 specification of Equation 2 for each group separately. For a bond to be included in a credit-risk group, all its credit-spread observations had to fall within the group bounds. This grouping procedure placed 405, 370, and 475 bonds in, respectively, the low-, medium-, and high-credit-risk groups. The results, reported in **Table 5**, show that the explained variation of credit-spread changes increases substantially with rising credit risk, from 35.89 percent for high-grade bonds to 67.51 percent for low-grade bonds. Common factors, with the exception of the Fama–French factors, increase in significance as credit risk increases. All the company-level variables except the change in P/B also increase in significance with increased credit risk. Consistent with the evidence in Avramov et al. (forthcoming 2007), Table 5 shows that momentum is most important in explaining the variation in credit-spread changes in the highest-credit-risk group.

We also estimated specifications M1–M4 within the three credit-risk groups (results available upon request). The explanatory power was always larger in the high-credit-risk group. Specifically, the adjusted R^2 for the low-credit-risk group (high-credit-risk group) was 28.51 percent (53.67 percent) for the M1 specification, 18.56 percent (28.37 percent) for the M2 specification, 34.96 percent (67.14 percent) for the M3 specification, and 14.67 percent (30.26 percent) for the M4 specification. Company characteristics were always significant in the high-credit-risk group.

Additional Robustness Tests. To further assess the robustness of our results, we investigated the impact of marketwide liquidity, as affected by Federal Reserve Board expansionary or contractionary policy, on credit-spread changes.[12] Our sample period was characterized by several Fed actions, such as raising and reducing the federal funds rate, that could have affected corporate bond liquidity. To incorporate the potential impact of Fed actions on credit spreads, we constructed a dummy variable indicating Fed expansionary cycles (dummy = 1 following a decrease of the federal funds rate) and contractionary cycles (dummy = 0 following an increase of the federal funds rate). The decision to change the federal funds rate is published in press releases summarizing the transcripts of the Federal Open Market Committee meetings, which are available on the Federal Reserve Board website (http://federalreserve.gov/fomc/). The press releases or transcripts do not explicitly state that the Fed is involved in a expansionary or contractionary policy, but the policy can be interpreted from the decisions to increase (or decrease) the federal funds target rate.

The results of adding the Fed cycle information to the regressions are reported in **Table 6**. Our previous results are unchanged except that the Fama–French factors have lost significance now even in the high-grade segment. The adjusted R^2s are also unchanged, which indicates that our results are robust to changes in liquidity induced by Fed intervention. More importantly, the Fed cycle dummy is significant only in the highest-grade group, where expansionary (contractionary) Fed policy reduces (increases) credit spreads.

We also used out-of-sample regressions to assess the robustness of our results. **Table 7** shows results from the regression reported in Table 5 reestimated to extend the sample period to August 2006. The explained variation has decreased slightly for the low- and medium-credit-risk groups and increased for the high-credit-risk group (R^2 of 70.16 percent), which widens the differences in explanatory power among the credit-risk

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Table 5. Common Factors, Company-Level Characteristics, and the Fama–French Factors (Regression M5) by Credit-Risk Group, Data for September 1990–January 2003
(*t*-statistics in parentheses)

Variable	Low Credit Risk	Medium Credit Risk	High Credit Risk
A. Common factors			
Change in aggregate P/B	–0.05	–0.08	–0.25
	(**–2.69**)	(**–2.56**)	(**–2.52**)
Change in aggregate idiosyncratic equity volatility	10.75	8.36	34.61
	(**2.35**)	(0.95)	(**2.24**)
5-Year government rates (5Y)	–0.23	–0.44	–0.74
	(**–14.66**)	(**–13.23**)	(**–16.51**)
Term-structure slope (30Y – 10Y)	–0.06	–0.13	0.10
	(–1.65)	(–1.93)	(0.81)
MKT factor	–0.00	0.00	–0.01
	(–0.03)	(0.60)	(**–2.14**)
SMB factor	–0.00	0.00	0.00
	(**–2.31**)	(0.22)	(0.51)
HML factor	–0.00	0.00	0.00
	(**–2.42**)	(**3.02**)	(0.61)
B. Company-level characteristics			
$\Delta Spread_{i,t-1}$	–0.21	–0.06	–0.04
	(**–13.21**)	(**–3.22**)	(**–2.42**)
$\Delta Spread_{i,t-2}$	–0.11	–0.10	–0.04
	(**–7.98**)	(**–6.69**)	(**–2.57**)
Stock return	0.00	–0.10	–0.44
	(0.00)	(–1.94)	(**–4.09**)
Stock momentum	–0.01	–0.12	–0.23
	(–0.32)	(**–3.15**)	(**–3.05**)
Change in idiosyncratic equity volatility	8.37	34.81	35.06
	(0.90)	(1.81)	(1.75)
Change in P/B	–0.04	–0.08	–0.13
	(**–2.71**)	(**–2.30**)	(–1.62)
Adjusted R^2	35.89%	54.83%	67.51%

Notes: Sample sizes were 405 bonds for the low-credit-risk group, 370 for the medium-credit-risk group, and 475 for the high-credit-risk group. Boldface indicates *t*-statistics that are significant at the 5 percent level.

groups. Aggregate idiosyncratic volatility has become more significant, especially for the middle- and high-credit-risk groups. The effects of spot rates and the term structure are also more pronounced, especially for the high-credit-risk group. The Fama–French factors are less important—the HML factor losing its statistical significance for all credit-risk groups. Company idiosyncratic volatility is now strongly significant. The company P/B, momentum, and stock returns have also markedly increased in significance.

Overall, extending the data out-of-sample reinforced our main results and conclusions, namely, that the structural model factors explain the variation of credit-spread changes, especially in the high-credit-risk group, and that common factors and company fundamentals play different roles in different credit-risk groups.

Table 6. M5 Regression Factors plus Federal Reserve Cycle Dummy by Credit-Risk Group, Data for September 1990–January 2003
(*t*-statistics in parentheses)

Variable	Low Credit Risk	Medium Credit Risk	High Credit Risk
A. Common factors			
Change in aggregate P/B	–0.05	–0.07	–0.24
	(**–2.66**)	(**–2.24**)	(**–2.42**)
Change in aggregate idiosyncratic equity volatility	10.35	12.68	38.76
	(**2.28**)	(1.47)	(**2.46**)
5-Year spot rate (5Y)	–0.23	–0.46	–0.73
	(**–14.17**)	(**–13.35**)	(**–16.19**)
Term-structure slope (30Y – 10Y)	–0.04	–0.17	0.13
	(–1.24)	(**–2.64**)	(1.05)
MKT factor	0.00	0.00	–0.01
	(0.17)	(0.30)	(**–2.41**)
SMB factor	–0.00	0.00	0.00
	(–1.93)	(0.07)	(0.65)
HML factor	–0.00	0.00	0.00
	(–1.83)	(**3.26**)	(0.50)
Fed cycle dummy (1 = expansion)	–0.01	–0.01	0.01
	(**–4.70**)	(–1.80)	(1.60)
B. Company-level characteristics			
$\Delta Spread_{i,t-1}$	–0.22	–0.07	–0.04
	(**–13.67**)	(**–3.65**)	(**–2.52**)
$\Delta Spread_{i,t-2}$	–0.12	–0.10	–0.04
	(**–8.12**)	(**–6.76**)	(**–3.01**)
Stock return	0.00	–0.10	–0.41
	(0.01)	(–1.73)	(**–3.75**)
Stock momentum	–0.02	–0.13	–0.23
	(–0.67)	(**–3.24**)	(**–2.98**)
Change in idiosyncratic equity volatility	1.11	27.81	35.01
	(0.12)	(1.40)	(1.76)
Change in P/B	–0.04	–0.08	–0.10
	(**–2.34**)	(**–2.15**)	(–1.26)
Adjusted R^2	35.28%	55.00%	66.56%

Notes: Sample sizes were 405 bonds for the low-credit-risk group, 370 for the medium-credit-risk group, and 475 for the high-credit-risk group. Boldface indicates *t*-statistics that are significant at the 5 percent level.

Our findings so far indicate that structural models capture a substantial amount of the time-series variation in individual bonds' credit-spread changes, especially among middle- and low-grade bonds. Still, the strongest evidence against structural models, provided by CDGM, is the possible existence of a latent factor that is unrelated to structural models and equity markets and that captures 75 percent of the residual variation of credit-spread changes. Therefore, we next investigate whether such a large latent factor is present in the residual variation of any credit-risk segment of our bond sample.

Unexplained Credit-Spread Variation. We implemented principal-components (PC) analysis of (1) credit-spread changes and (2) the residuals of the time-series regressions. These residuals reflect

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Table 7. Explained Variation in Credit-Spread Changes in Regression M5 by Credit-Risk Group, Data for September 1990–August 2006
(*t*-statistics in parentheses)

Variable	Low Credit Risk	Medium Credit Risk	High Credit Risk
A. Common factors			
Change in aggregate P/B	–0.02	–0.10	–0.24
	(**–2.11**)	(**–2.16**)	(**–2.24**)
Change in aggregate idiosyncratic equity volatility	11.24	12.61	13.27
	(**2.51**)	(**3.02**)	(**3.13**)
5-Year spot rate (5Y)	–0.19	–0.36	–0.68
	(**–2.39**)	(**–18.63**)	(**–32.88**)
Term-structure slope (30Y – 10Y)	–0.39	–0.03	0.27
	(–1.85)	(–0.92)	(**3.41**)
MKT factor	–0.00	–0.00	–0.01
	(–0.32)	(–1.91)	
SMB factor	–0.01	–0.00	
	(**–3.14**)	(–0.85)	
HML factor	–0.03	–0.00	
	(–1.55)	(–0.52)	
B. Company-level characteristics			
$\Delta Spread_{i,t-1}$	0.10	–0.06	
	(1.03)	(**–5.94**)	
$\Delta Spread_{i,t-2}$	–0.35	–0.07	0.01
	(**–2.69**)	(**–8.21**)	(1.04)
Stock return	0.68	–0.38	–0.54
	(0.59)	(**–2.47**)	(**–8.32**)
Stock momentum	–0.41	–0.11	–0.22
	(–1.86)	(**–4.84**)	(**–6.77**)
Change in idiosyncratic equity volatility	–13.80	42.31	35.59
	(–0.98)	(**3.72**)	(**3.85**)
Change in P/B	–0.42	–0.19	–0.15
	(–0.84)	(–0.91)	(**–1.98**)
Adjusted R^2	30.48%	49.95%	70.16%

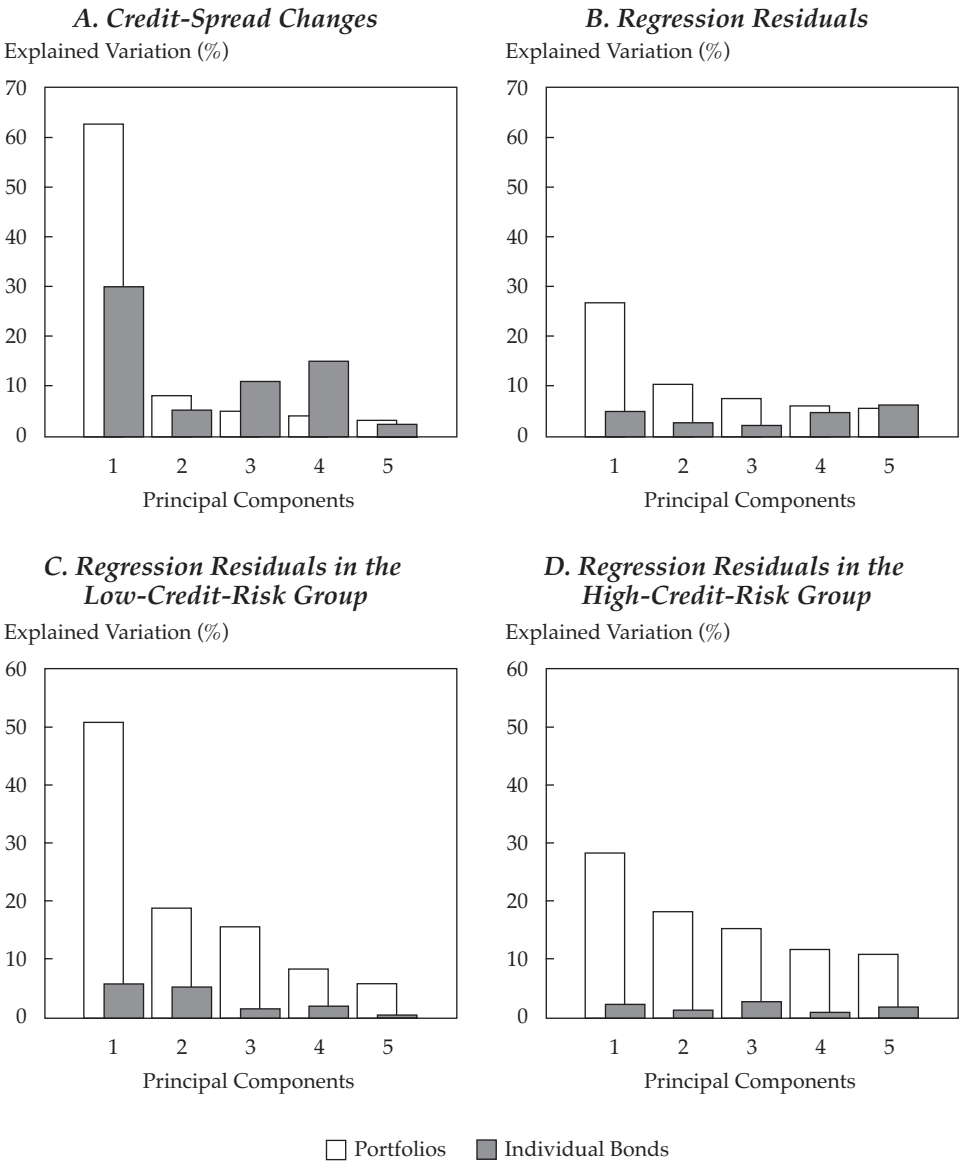
Notes: Sample sizes are the same as in Table 6. Boldface indicates *t*-statistics that are significant at the 5 percent level.

variation unexplained by structural models. Comparing the two illustrates how well our variables capture the common variation in credit-spread changes. The purpose of this PC analysis was to detect whether significant unexplained systematic variation remains in the residuals, rather than to establish the number of driving factors. For this reason, we looked only at the first five components and focused on the strength of the first latent factor.

The 2,375 corporate bond credit spreads and regression residuals were each assigned to one of 35 portfolios formed as the interaction of five credit-spread and seven time-to-maturity categories. PC analysis was applied to portfolios rather than individual bonds because bonds expire or default and were thus not available for the entire sample period.

Chart A of **Figure 3** summarizes the PC analysis based on the *total* variation in spread changes; Chart B summarizes the *unexplained* variation reflected by the regression residuals. The white bars in Chart A point to a strong common factor in the *portfolio-aggregated* credit-spread changes that captures 63 percent of their variation. The explanatory power of

Figure 3. Principal-Components Analyses: Average R^2s



each subsequent principal component is significantly smaller. When we focus on the portfolios of residuals in Chart B (from model M3), however, the white bars show that the first principal component accounts for less than 28 percent of the residuals' variation. This evidence is apparently at odds with previous findings (i.e., CDGM) of a much stronger latent factor in the regression residuals. Portfolio-grouping procedures may help explain the difference. For example, when we decreased the number of regression residual portfolios from 35 to 15, the latent first factor captured a much larger percentage, 45 percent, of the unexplained variation.

To investigate this aspect further, we regressed the *individual* credit-spread changes on each of the first five portfolio-based latent factors. We report the average R^2s in the dark bars overlaying the white bars in Chart A of Figure 3.[13] We did the same for the individual residuals and the corresponding portfolio-based residual latent factors in Chart B. The dark bars in Chart A reveal a prominent systematic factor that captures 30 percent of the common variation in individual bonds. Moreover, each of the third and fourth portfolio-based latent factors also captures more than 10 percent of the individual spread variation, which suggests that there is indeed substantial systematic variation in individual credit-spread changes.[14] However, our structural model variables capture most of this systematic variation. Indeed, the dark bars in Chart B show no significant latent factor in the individual residuals. Each of the first five latent factors captures less than 6 percent of the variation in individual bond residuals.

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Because the variation explained by structural models is much smaller in high-grade bonds, we applied PC analysis to the high- and low-grade groups separately to discover whether systematic variation remained in them. (The PC analysis was performed on the basis of 15 portfolios because of the reduced number of bonds within each credit-risk group.) Charts C and D in Figure 3 summarize this analysis. The white bars in both plots demonstrate that there is a stronger latent factor in the unexplained variation of the portfolio-aggregated residuals of high-grade bonds (more than 50 percent of their common variation captured) than in low-grade bonds (less than 30 percent captured). Repeating the previous analysis with individual-bond residuals (thus, a much larger sample) revealed that most of the common variation is spurious and driven by portfolio grouping. Indeed, regressing the individual bond residuals on the latent factors showed that each factor explained less than 7 percent of the common variation in individual high-grade bond residuals and less than 4 percent in individual low-grade bond residuals.

These findings suggest that our parsimonious set of structural model variables successfully captures essentially all of the systematic variation in individual bonds' credit-spread changes for bonds of all credit-risk levels. Although the explained variation is smaller in high-grade bonds than in lower-grade bonds, structural models are still successful in the high-grade credit group; the models leave little systematic variation unexplained.

Conclusion

Using 2,375 corporate bonds from the period 1990–2003, we documented that structural model variables successfully explain credit-spread dynamics. A parsimonious set of aggregate and company-level variables explained about 68 percent, 55 percent, and 36 percent of the total variation in credit-spread changes of, respectively, low-, middle-, and high-grade individual bonds. Principal-components analysis of the individual-bond regression residuals revealed that for all bond grades, structural models successfully capture the systematic variation in credit-spread changes.

We also demonstrated that the Fama–French factors capture some of the systematic risk in credit-spread changes. The explanatory power of the Fama–French factors increased with increasing credit risk. When the Fama–French factors were combined with our proposed set of determinants, however, the Fama–French factors lost significance for each credit-risk category, which suggests that structural model factors capture the systematic risk in credit-spread changes better than do the Fama–French factors.

We developed further evidence on the viability of structural models in empirical corporate bond pricing. Building on recent innovations in asset pricing, we conclude that idiosyncratic volatility and the price-to-book ratio have a strong basis in a structural model framework. We found both variables to be economically and statistically significant in explaining the time-series variation in corporate credit-spread changes. Hence, these variables should be considered together with the more traditional ones in studies of bond-level credit risk.

These findings are robust to liquidity considerations. In particular, we showed that changes in the overall bond market liquidity because of Fed tightening and easing cycles do not affect the documented support for structural models.

Why are our findings so different from the closely related work of CDGM? The findings differ because CDGM focused on investment-grade bonds but we included all grades, and high-yield bonds behave substantially differently from investment-grade bonds. Company-level fundamentals and common factors are important determinants of credit-risk changes among high-yield bonds but not among investment-grade bonds. When we focused on low-credit-risk bonds, our results were qualitatively similar to those of CDGM.

In addition, CDGM documented a strong latent factor in the unexplained variation of credit-risk changes, from which they concluded that structural model variables do not explain credit-spread changes but are driven by supply/demand shocks. We showed that the presence of a dominant latent factor can arise from bundling the individual regression residuals into portfolios. In particular, focusing on individual regressions yielded no dominant latent factor in the unexplained variation.

Finally, we explored more variables than CDGM explored. In particular, we found idiosyncratic volatility and the book-to-market ratio to be significant determinants of changes in corporate credit risk.

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This article qualifies for 1 PD credit.

Notes

1. Eom, Helwege, and Huang (2004) and Huang and Huang (2003) linked the success of structural models to the relative size of the credit-risk component in spread levels (that is, the size had to be large for success of the model). Even a small such component can account for most of the spread changes, however, if the non-credit-risk component shows little variation over time.
2. Focusing on changes in credit spreads rather than levels is also justified from a statistical standpoint. The level tends to be nonstationary, but the spread change is well behaved. In particular, using the augmented Dickey–Fuller test, we found that 99 percent of our series of credit-spread changes were stationary at the 5 percent significance level, although the vast majority of the level series were not.
3. See Crosbie and Bohn (2003).
4. Credit blowups usually result from defaulted investment-grade credits, which are then relegated to junk bond status. In this situation, the credit spread can jump from a few hundred to tens of thousands of basis points. The distressed high-grade companies are usually referred to as "fallen angels."
5. For much of the analysis, the bond sample was divided into three credit-risk groups on the basis of the bonds' credit-spread levels. The tercile bounds were calculated as the 33 1/3 and 66 2/3 credit-spread percentiles on the basis of all credit-spread observations in the full sample of bonds. We did not use bond ratings to form groups because many bonds were not rated by any agency. Using the bonds with an S&P rating in Datastream, however, we did verify a monotonic relationship between spread level and credit rating for all rating groups (results not reported).
6. To compute the average rating, we first converted the alphabetic S&P ratings into numeric equivalents, as shown in the Table 1 notes.
7. We replicated all of the analysis but with alternative maturities, and the results were virtually identical (results available upon request).
8. See http://mba.tuck.dartmouth.edu/pages/faculty/ken.french/data_library.html.
9. For robustness, we also calculated 6- and 12-month momentum variables as, respectively, the cumulative return for months 4–6 and months 7–12 (as in Brennan et al. 1998).
10. Testing the momentum variable for longer lags (not reported) did not improve significance.
11. We also ran regressions using alternative term-structure variables, but the results (available upon request) remained unchanged.
12. On the bond level, liquidity has been studied mainly as a component of credit-spread *level* (see Ericsson and Renault 2006). Because individual-bond liquidity is stable through time (see Hotchkiss, Jostova, and Warga 2003), liquidity is less of a consideration in studying credit-spread *changes*.
13. Comparing the average R^2s from individual regressions on each factor is equivalent to comparing the weights of the eigenvalues from the PC analysis.
14. Note that because the 35 portfolios span a different space from that spanned by the 2,375 individual series, the first five principal components constructed on the basis of the portfolios are not necessarily monotonically decreasing in their explanatory power of the individual series.

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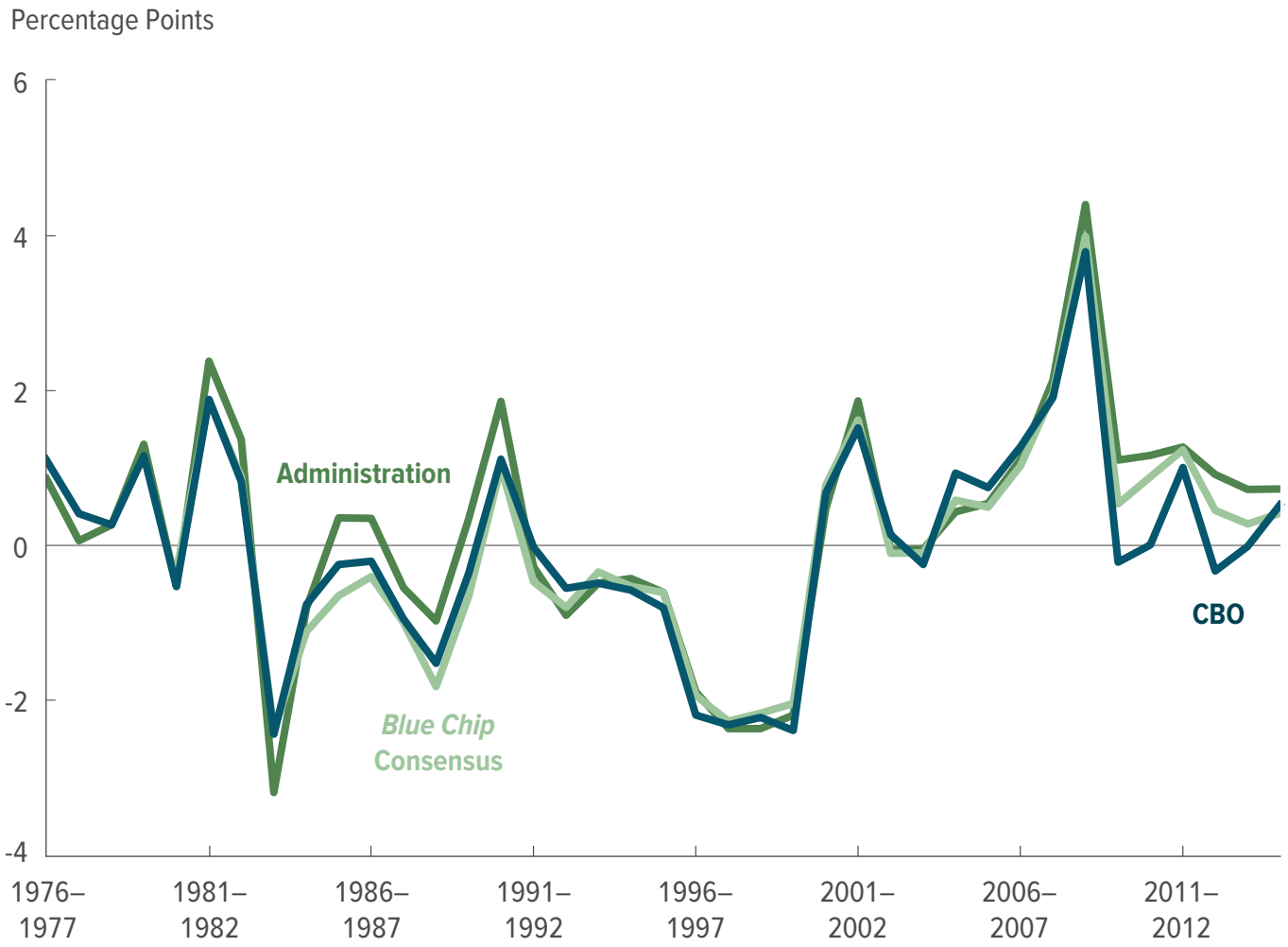
CBO's Economic Forecasting Record: 2017 Update



Forecast Minus Actual Growth of Inflation-Adjusted Output: Two-Year Forecasts

OCTOBER 2017

Notes

Many of the figures and the two tables show data from the *Blue Chip* consensus, which is an average of about 50 private-sector forecasts published in *Blue Chip Economic Indicators*.

Supplemental data, including an interactive graphic, are posted along with this report on CBO's website (www.cbo.gov/publication/53090).

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CBO's Economic Forecasting Record: 2017 Update

Summary

For four decades, the Congressional Budget Office has prepared economic forecasts to use in making its projections for the federal budget. Forecasts of output, inflation, interest rates, and wages and salaries, in particular, play a significant role in CBO's budget analysis. For example, to project receipts from individual income taxes, CBO uses its forecasts of wages and salaries.

CBO regularly evaluates the quality of its economic forecasts for several reasons.[1] One is to determine if it needs to change its forecasting methods. For example, partly in response to past forecast errors, CBO has changed the way it forecasts productivity growth and interest rates in recent years. Another reason for evaluating past forecasts is to calculate the errors in those forecasts, which in turn can be used to approximate the range of errors or uncertainty in the agency's current forecasts. Finally, publishing such evaluations gives readers a tool to assess the usefulness of the agency's projections and is thus one way in which CBO demonstrates its commitment to transparency.

To evaluate its economic forecasts, CBO compares them with the economy's actual performance and with the Administration's forecasts, which are published in the Office of Management and Budget's annual budget documents, and the *Blue Chip* consensus—an average of about 50 private-sector forecasts published in *Blue Chip Economic Indicators*. Such comparisons can indicate the extent to which imperfect information and analysis may have caused CBO to miss patterns or turning points in the economy. They can also help the agency identify areas where it has tended to make larger errors than other analysts. This report evaluates CBO's economic forecasts over two-year and five-year periods. The span of years that CBO examined for this evaluation differs by variable and by forecast period on the basis of data availability.

How Does CBO's Forecasting Record Compare With Those of the Administration and the *Blue Chip* Consensus?

CBO's forecasting record is comparable in quality to those of the Administration and the *Blue Chip* consensus. When CBO's projections were inaccurate by large margins, the other two forecasters' projections tended to have similar errors because all forecasters faced the same challenges. For example, all three sets of forecasts of inflation were relatively inaccurate during the late 1970s and early 1980s but generally became more accurate as inflation stabilized in more recent decades.

Do CBO's Forecasts Exhibit Statistical Bias?

Statistical bias is the tendency of a forecaster's projections to be too low or too high over a period of time. A simple and widely used indicator of bias is the mean error. By that measure, CBO's forecasts of most economic indicators examined here have tended to be too high by small amounts, but the agency's two-year forecasts of real (inflation-adjusted) output were slightly too low, on average.

After evaluating the mean errors of its forecasts, CBO reached two conclusions:

- CBO's two-year forecasts of output growth and inflation have been less biased than its two-year forecasts of interest rates and the growth of wages and salaries, which exhibit a sizable upward bias—that is, they have tended to be higher than actual values by a larger amount (see Figure 1).[2]

- For most economic indicators, the mean errors of CBO's five-year forecasts (which are discussed in the second half of the report) have been slightly larger than those of the agency's two-year forecasts. That pattern shows that CBO has a tendency to overestimate economic trends over the longer term.

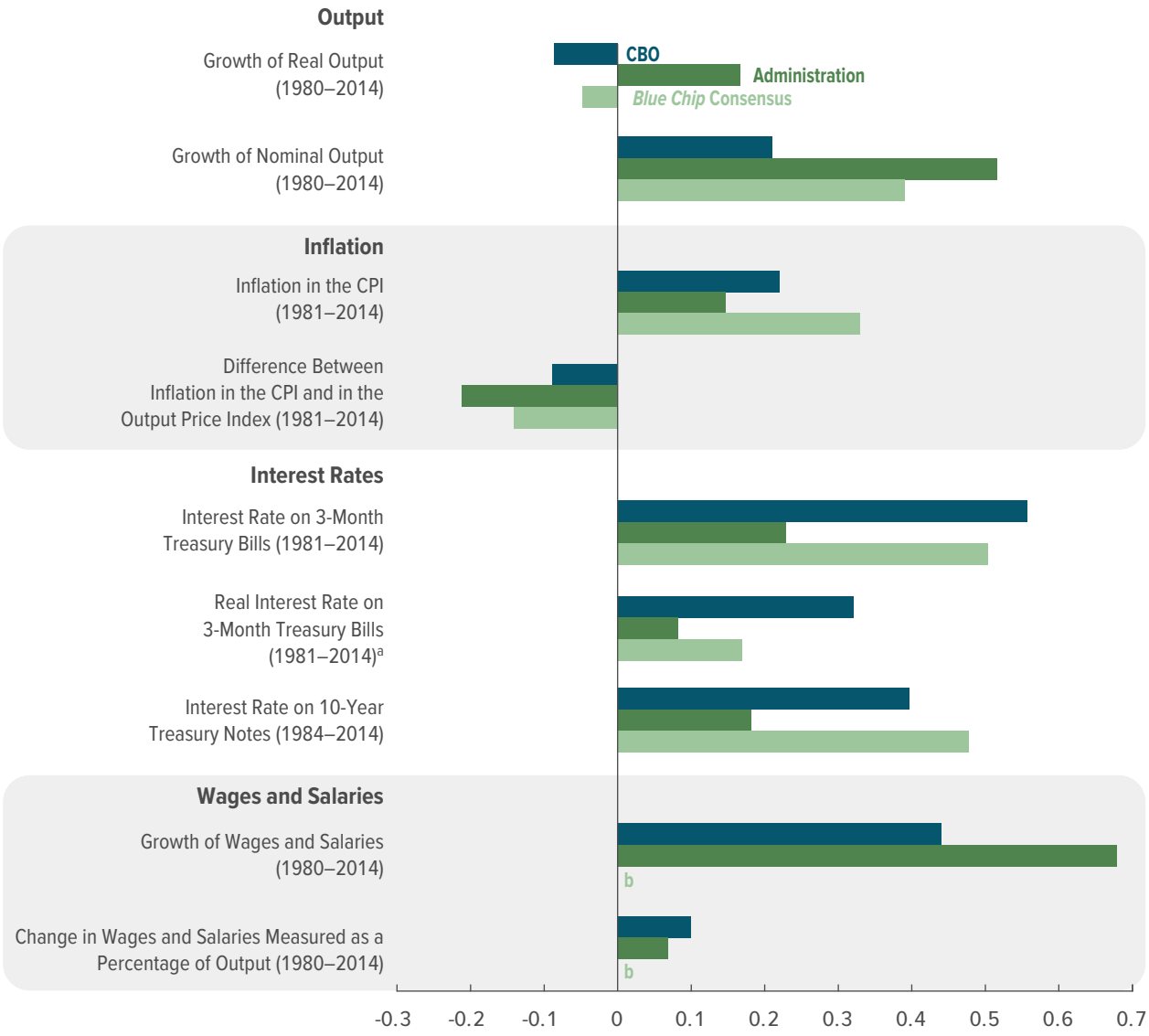
1. CBO has also evaluated its revenue forecasts. See Congressional Budget Office, *CBO's Revenue Forecasting Record* (November 2015), www.cbo.gov/publication/50831. The agency is currently analyzing its past projections of outlays.

2. Forecast errors throughout this report were calculated as projected values minus actual values; thus, a positive error is an overestimate.

Figure 1.

Mean Errors of Two-Year Forecasts

Percentage Points



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Bureau of Economic Analysis; Bureau of Labor Statistics; Federal Reserve.

Forecast errors are projected values minus actual values; thus, a positive error is an overestimate. The mean error is the arithmetic average of the forecast errors.

Date ranges refer to the years in which the forecasts were made. For details on the data underlying the summary measures presented here, see the appendix.

Output is either GDP or (before 1992) GNP. Real output is nominal output adjusted to remove the effects of inflation.

CPI = consumer price index; GDP = gross domestic product; GNP = gross national product.

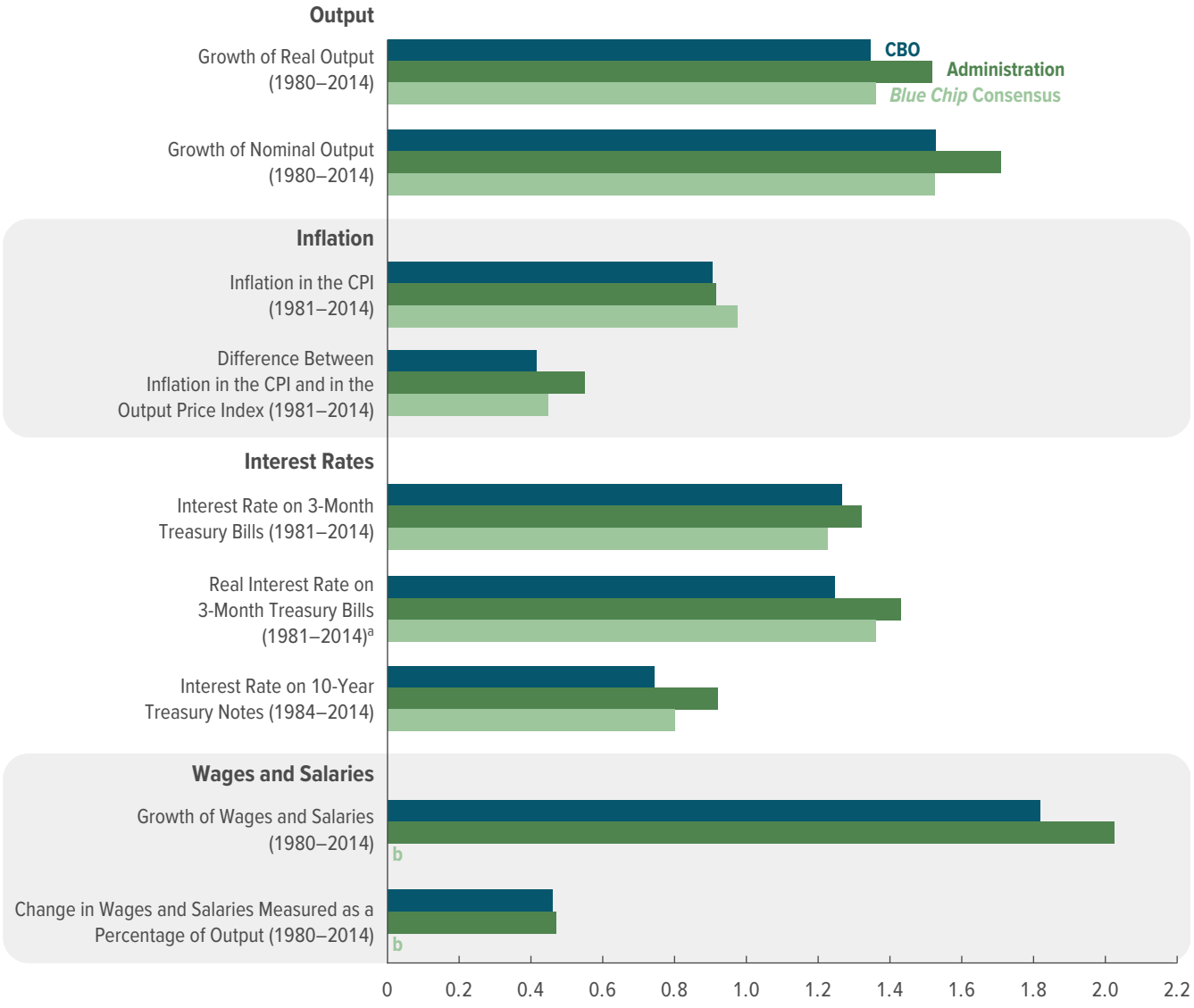
a. The real interest rate is the nominal interest rate deflated by the projected rate of growth in the CPI.

b. The *Blue Chip* consensus does not include forecasts of wages and salaries.

Figure 2.

Root Mean Square Errors of Two-Year Forecasts

Percentage Points



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Bureau of Economic Analysis; Bureau of Labor Statistics; Federal Reserve.

Forecast errors are projected values minus actual values. The root mean square error is calculated by squaring the forecast errors, averaging those squares, and taking the square root of that average.

Date ranges refer to the years in which the forecasts were made. For details on the data underlying the summary measures presented here, see the appendix.

Output is either GDP or (before 1992) GNP. Real output is nominal output adjusted to remove the effects of inflation.

CPI = consumer price index; GDP = gross domestic product; GNP = gross national product.

a. The real interest rate is the nominal interest rate deflated by the projected rate of growth in the CPI.

b. The *Blue Chip* consensus does not include forecasts of wages and salaries.

Other forecasters' projections generally exhibited bias of a similar magnitude and in the same direction. The mean errors of the *Blue Chip* consensus forecasts were very similar to those of CBO's forecasts. The Administration's forecasts of the growth of real output had larger mean errors than CBO's forecasts and the *Blue Chip* consensus, but its forecasts of inflation and interest rates exhibited less upward bias than did the other two forecasters'.

How Accurate Are CBO's Forecasts?
Accuracy is the degree to which forecast values are dispersed around actual outcomes. One widely used measure of accuracy is the root mean square error (RMSE). By that measure, CBO's two-year forecasts are generally as accurate as those of the *Blue Chip* consensus and, for most economic indicators, slightly more accurate than the Administration's two-year forecasts (see Figure 2). The accuracy of all three sets of five-year forecasts is comparable.

Comparing the accuracy of its two-year and five-year forecasts, CBO observed the following:

- CBO's five-year forecasts of output and inflation are more accurate than its two-year forecasts of those variables, in part because long-term forecasts rest more on underlying trends in the economy than on short-term cyclical movements, which are very difficult to predict.
- CBO's five-year interest rate forecasts are less accurate than its two-year forecasts of those rates because of the large and unexpectedly persistent decline in long-term interest rates that began in the early 1980s.
- For its forecasts of wages and salaries, CBO's findings are less clear-cut. The agency's two-year and five-year forecasts of the growth of wages and salaries are equal in terms of accuracy, but its five-year forecasts of the change in wages and salaries measured as a percentage of output are more accurate than the corresponding two-year forecasts.

What Are Some Sources of Forecast Errors?
CBO's and other forecasters' largest forecast errors often stem from the difficulties of anticipating three key developments:

- Turning points in the business cycle—that is, the beginning and end of recessions;
- Changes in trends in productivity; and
- Changes in crude oil prices.

How Do Assumptions About Fiscal Policy Affect Forecast Errors?
Fiscal policy refers to the federal government's policies on taxes and spending. Assumptions about fiscal policy are an important ingredient of an economic forecast because such policy affects output, inflation, interest rates, and wages and salaries. To provide lawmakers with a benchmark against which they can assess potential changes in the law, CBO constructs its economic forecasts under the assumption that federal fiscal policy will generally remain the same as under current law. By contrast, the Administration's forecasts reflect the assumption that the policies in the President's proposed budget will be adopted. Forecasters in the private sector (such as those who contribute to the *Blue Chip* consensus) form their own projections about the future of federal fiscal policy, so their forecasts reflect changes in law that they anticipate will be made.

Those different assumptions about fiscal policy account for some of the variation among forecasts and thus in forecast errors. Assumptions about fiscal policy can be particularly significant when policymakers are considering major changes to current law. For example, in 2009 and 2010, CBO's two-year forecasts of real output growth diverged noticeably from the Administration's forecasts and the *Blue Chip* consensus because of the different fiscal policy assumptions underlying the forecasts.

What Are the Limitations of This Evaluation?
This evaluation has three limitations. First, all forecasters change their procedures over time, which makes it hard to draw inferences about future errors. Second, because forecasters make different assumptions about future fiscal policy, it is difficult to compare the quality of forecasts without considering the role of expected changes in laws. Finally, the historical data (on output and income, for example) that forecasters use to make economic projections are often revised, which can complicate the task of interpreting forecast errors.

CBO's Methods for Evaluating Forecasts

CBO evaluates the quality of its forecasts by examining its past forecast errors and comparing them to the errors in the Administration's forecasts and the *Blue Chip* consensus. The *Blue Chip* consensus is particularly useful

for comparisons because it incorporates a variety of forecasts and therefore reflects a broader blend of sources and methods than any single forecaster would use. Over time, composite forecasts like the *Blue Chip* consensus often provide better estimates than any projection made by a single forecaster or using a single method.[3]

This report evaluates CBO's economic forecasts over the first two years and over the first five years of CBO's 10-year baseline projection period. The forecasts are made at the beginning of a calendar year, and the errors are calculated by subtracting the average actual value over the forecast period from the average projected value. The two-year forecasts include the full period that is used to prepare the baseline budget for the upcoming fiscal year. The five-year forecasts are used to examine the accuracy of longer-term projections of several variables that are important for CBO's baseline budget projections.[4]

The span of years evaluated differs by economic indicator and by forecast horizon depending on the data available. CBO's and the Administration's forecasts published in the early months of the years 1976 to 2014 were examined, but those published in early 2015 were not, because actual data for all of 2016—which are necessary to evaluate the two-year forecasts made in 2015—were not available when the analysis for this report was completed. To ensure that differences in the availability of forecast data did not affect the interpretation of forecast errors, the ranges of years covered by the comparisons were determined by the earliest possible year for which data from the *Blue Chip* consensus were available. The first two-year *Blue Chip* consensus forecast that CBO examined for this evaluation was released in 1980 and included projections of real and nominal output. In 1981, forecasts of inflation and 3-month interest rates were also included. *Blue Chip* first published five-year forecasts of real and nominal output in 1979, of inflation and the 3-month interest rate in 1983, and of the 10-year Treasury note rate in 1984.[5]

This report updates CBO's 2015 *Economic Forecasting Record* with additional forecasts and new and revised historical data.[6] This evaluation adds two years of CBO's, the Administration's, and *Blue Chip*'s forecasts that were not included in the previous report—the two-year forecasts published in 2013 and 2014 and the five-year forecasts published in 2010 and 2011. It also includes a few additional forecasts from the early years of the *Blue Chip* consensus and revisions to previously published historical data that have been made since the last report was released. The additional data and revisions to older data did not significantly alter the main findings from the previous report—namely, that the quality of CBO's two-year and five-year forecasts is similar to that of other organizations' forecasts.

Another difference between this report and previous versions is that this report analyzes five-year forecasts of interest rates. In the past, CBO analyzed only two-year forecasts of interest rates.

Calculation of Forecast Errors

For this report, CBO measured forecast errors as the difference between the average forecast value and the average actual value over each forecast period. (See Box 1 for an example of how CBO calculates its forecast errors.) The actual values are based on the latest available data from the Bureau of Economic Analysis (BEA) and other statistical agencies. A positive error indicates that the actual value of the indicator was lower than CBO expected, and a negative error indicates that it was higher than expected.

The method used to calculate the forecast errors for this report differs slightly from that used in CBO's evaluation

3. See Allan Timmermann, "Forecast Combinations," in Graham Elliott, Clive W. J. Granger and Timmermann, eds., *Handbook of Economic Forecasting*, vol. 1 (North Holland, 2006), pp. 135–196, https://doi.org/10.1016/S1574-0706(05)01004-9; Andy Bauer and others, "Forecast Evaluation with Cross-Sectional Data: The *Blue Chip* Surveys," *Economic Review*, vol. 88, no. 2 (Federal Reserve Bank of Atlanta, 2003), pp. 17–31, http://tinyurl.com/yb6bj9dq; Henry Townsend, "A Comparison of Several Consensus Forecasts," *Business Economics*, vol. 31, no. 1 (January 1996), pp. 250–261, www.jstor.org/stable/23487509; and Robert Clemen, "Combining Forecasts: A Review and Annotated Bibliography," *International Journal of Forecasting*, vol. 5, no. 4 (1989), pp. 559–583, https://doi.org/10.1016/0169-2070(89)90012-5.

4. CBO's baseline projection period is currently 10 years, but in the past, it has been as short as 5 years.

5. See the appendix for further details on the choice of historical time-series data and on the sources of the forecast data used in the comparisons.

6. See Congressional Budget Office, *CBO's Economic Forecasting Record: 2015 Update* (February 2015), www.cbo.gov/publication/49891.

Box 1.

How CBO Calculates Economic Forecast Errors

The Congressional Budget Office calculates forecast errors by subtracting the average actual value of an economic indicator over a two-year (or five-year) period from the average projected value of that indicator over the same period. For example, to calculate the error for the two-year forecast of the growth of real (inflation-adjusted) gross domestic product (GDP) that was published in the January 2000 *Budget and Economic Outlook*, CBO first calculated the geometric average of the projected growth rates of real GDP for calendar years 2000 and 2001, which was 3.2 percent.[1] The agency then calculated the average actual growth rate of real GDP for those two years, which was 2.5 percent. Finally, it subtracted the average actual rate of 2.5 percent from the average projected rate of 3.2 percent, resulting in an error of 0.7 percentage points. To determine the error for the five-year forecast made that same year, CBO took the averages of projected and actual output growth rates for calendar years 2000 through 2004.

1. The geometric average is the appropriate measure for averaging growth rates. It was used to calculate the average for all indicators except the change in wages and salaries as a percentage of output. Because that indicator is a ratio rather than a growth rate, the appropriate measure for averaging is the arithmetic average.

Example: Calculating the Error in the Two-Year Forecast of the Growth of Real GDP That CBO Published in January 2000

	CBO's Forecast Rate	Actual Rate
2000	3.3%	4.1%
2001	3.1%	1.0%

Calculate the Two-Year Average

3.2% – 2.5% = **0.7** percentage points

The error for the two-year forecast made in 2000 is . . .

Sources: Congressional Budget Office; Bureau of Economic Analysis.

GDP = gross domestic product.

of errors in revenue projections.[7] In that evaluation, projection errors were calculated for a single fiscal year. For example, the error in CBO's two-year revenue projection for 2007 is the percentage difference between the actual amount of revenues received in fiscal year 2007 and the revenues projected for that year in January 2006.[8]

7. Congressional Budget Office, *CBO's Revenue Forecasting Record* (November 2015), www.cbo.gov/publication/50831.

8. In CBO's evaluation of its revenue projections, the agency calculated errors as the percentage difference (rather than the simple difference used in this report) between the projected and actual values because revenues are expressed as dollar amounts. If the errors in revenue projections were measured as simple differences in dollar amounts, they would be difficult to compare over time. (A $5 billion error in 1992, for example, would be significantly larger than a $5 billion error in 2014.) The simple difference is more appropriate here because this report evaluates errors in forecasts of economic indicators that are expressed as rates or percentages—growth rates, interest rates, and changes in wages and salaries as a percentage of output. Forecast errors in this report are thus percentage-point differences between forecast and actual values.

Assessment of Forecasts

Like CBO's previous studies of its economic forecasts, this evaluation focuses on two indicators of quality:

statistical bias and accuracy. Other characteristics of forecast quality—such as whether forecasters optimally incorporate all relevant information when making their projections—are harder to assess.[9]

Statistical Bias. Statistical bias indicates the tendency of a set of forecasts to err in a certain direction. To measure bias, CBO used the mean error—that is, the arithmetic average of the forecast errors—which is the simplest and most widely used measure. CBO measures bias to determine whether its forecasts are systematically too high or too low. The agency's goal is to provide forecasts of economic indicators that represent the middle of the distribution of possible outcomes. The presence of bias might indicate that the forecast methods should be modified to eliminate persistent error.

The mean error does not, however, provide a complete characterization of the quality of a forecast. Because positive and negative errors are added together to calculate the average, underestimates and overestimates offset one another. A small mean error might indicate that all the forecasts had only small errors, but it could also result from large overestimates and large underestimates that offset one another. Experimenting with alternatives to the mean error measure, several analysts outside of CBO have used more elaborate techniques to test for bias in the agency's forecasts.[10]

Accuracy. The accuracy of a set of forecasts is the degree to which forecast values are dispersed around actual outcomes. Narrower dispersion indicates greater accuracy. Generally, the more accurate CBO's economic forecasts are, the more accurate its forecasts of revenues and outlays will be.

Two commonly used measures of accuracy are the mean absolute error and the root mean square error. The mean absolute error is the arithmetic average of the forecast errors without regard to the direction of the errors (that is, the negative signs are removed from underestimates before averaging). Thus, unlike in the mean error, in the mean absolute error, underestimates and overestimates do not offset one another. The RMSE—the calculation of which involves squaring the errors (thus removing the negative signs)—also shows the size of the error without regard to direction, but it places a greater weight on larger deviations.[11]

9. Several studies that have examined how well relevant information has been incorporated into CBO's economic forecasts—a characteristic referred to as forecast efficiency—have found that the agency's forecasts are relatively efficient. See, for example, Robert Krol, "Forecast Bias of Government Agencies," *Cato Journal*, vol. 34, no. 1 (Winter 2014), pp. 99–112, https://tinyurl.com/y7cmapw3 (PDF, 88 KB); Stephen M. Miller, "Forecasting Federal Budget Deficits: How Reliable Are US Congressional Budget Office Projections?" *Applied Economics*, vol. 23, no. 12 (December 1991), pp. 1789–1799, http://doi.org/10.1080/00036849100000168; and Michael T. Belongia, "Are Economic Forecasts by Government Agencies Biased? Accurate?" *Review*, vol. 70, no. 6 (Federal Reserve Bank of St. Louis, November/December 1988), pp. 15–23, http://tinyurl.com/ychze7ah. Although statistical tests can identify sources of inefficiency in a forecast after the fact, they generally do not indicate how such information could be used to improve forecasts when they are being made.

10. One such alternative approach to testing a forecast for bias is based on linear regression analysis of actual values compared with forecast values. For details of that method, see Jacob A. Mincer and Victor Zarnowitz, "The Evaluation of Economic Forecasts," in Jacob A. Mincer, ed., *Economic Forecasts and Expectations: Analysis of Forecasting Behavior and Performance* (National Bureau of Economic Research, 1969), pp. 3–46, www.nber.org/chapters/c1214. Studies that have used that method to evaluate CBO's and the Administration's short-term forecasts have not found statistically significant evidence of bias over short forecast horizons. See, for example, Robert Krol, "Forecast Bias of Government Agencies" *Cato Journal*, vol. 34, no. 1 (Winter 2014), pp. 99–112, https://tinyurl.com/y7cmapw3 (PDF, 88 KB); Graham Elliott and Allan Timmermann, "Economic Forecasting," *Journal of Economic Literature*, vol. 46, no. 1 (March 2008), pp. 3–56, https://doi.org/10.1257/jel.46.1.3; George A. Krause and James W. Douglas, "Institutional Design Versus Reputational Effects on Bureaucratic Performance: Evidence from U.S. Government Macroeconomic and Fiscal Projections," *Journal of Public Administration Research and Theory*, vol. 15, no. 2 (April 2005), pp. 281–306, https://doi.org/10.1093/jopart/mui038; and Michael T. Belongia, "Are Economic Forecasts by Government Agencies Biased? Accurate?" *Review*, vol. 70, no. 6 (Federal Reserve Bank of St. Louis, November/December 1988), pp. 15–23, http://tinyurl.com/ychze7ah. For more elaborate studies of bias that included CBO's forecasts among a sizable sample, see J. Kevin Corder, "Managing Uncertainty: The Bias and Efficiency of Federal Macroeconomic Forecasts," *Journal of Public Administration Research and Theory*, vol. 15, no. 1 (January 2005), pp. 55–70, https://doi.org/10.1093/jopart/mui003; and David Laster, Paul Bennett, and In Sun Geoum, "Rational Bias in Macroeconomic Forecasts," *Quarterly Journal of Economics*, vol. 114, no. 1 (February 1999), pp. 293–318, https://doi.org/10.1162/003355399555918.

11. The RMSE is calculated by squaring the forecast errors, averaging those squares, and taking the square root of that average. The mean square forecast error is equal to the square of the bias in the errors plus the variance (that is, the square of the standard deviation) of the errors.

For this evaluation, CBO focused primarily on the RMSE, which can be used to gauge the uncertainty surrounding future forecasts. A smaller RMSE suggests that a forecaster's projections have less uncertainty surrounding them than they would if the RMSE was larger. Each time CBO produces a forecast, it does so with the expectation that the forecast will be unbiased, which implies that the RMSE of CBO's past forecasts approximates the standard deviation associated with the new forecast. In general, when the errors of a given set of forecasts are normally distributed around a mean error of zero—that is, if the misestimates are roughly symmetrically distributed around zero and there are more relatively small errors than large ones—about two-thirds of the forecasts will have misestimates within a range of plus or minus one RMSE. For example, the RMSE of CBO's two-year forecasts of the growth of real output is 1.3 percentage points (see Table 1). An RMSE of that value indicates that there is about a two-thirds chance that the actual average growth rate over the next two years will be within 1.3 percentage points of the rate in CBO's current forecast.[12]

Limitations of the Forecast Evaluations

There are three reasons to be cautious when interpreting the results of this forecast evaluation: Forecasting methods change over time, different forecasters make different assumptions about future fiscal policy, and many of the actual values of the projected variables are periodically revised.

Over time, CBO and other forecasters have changed the procedures that they use to develop economic forecasts—partly in response to changes in the economy and partly in response to advances in forecasting methods. Although such changes are aimed at improving the quality of forecasts, they make it difficult to draw inferences about future errors.

Another limitation of this analysis is that the forecasters considered here make different assumptions about future changes in fiscal policy, and it can be impossible to isolate those assumptions from each forecaster's overall economic analysis. CBO is required by statute to assume that future fiscal policy will generally reflect the provisions in current law, an approach that derives from the agency's responsibility to provide a benchmark for lawmakers as they consider proposed changes in law.[13] When the Administration prepares its forecasts, however, it assumes that the fiscal policy in the President's proposed budget will be adopted. The private forecasters included in the *Blue Chip* survey make their own assumptions about fiscal policy, but the survey does not report them. Forecast errors may be driven by those different assumptions, especially when forecasts are made while policymakers are considering major changes to current fiscal policy.[14]

A third reason to be cautious when interpreting the results of this forecast evaluation is that the historical values of many of the data series that CBO and other analysts forecast are periodically revised by the agencies that compile those data. BEA and other agencies use various methods and statistical definitions to estimate gross domestic product (GDP) and other economic indicators on the basis of data that they and others collect. Those agencies periodically revise their published estimates of economic indicators for past years as more information becomes available and as definitions and methods improve. Not all series—the consumer price index (CPI) and interest rates, for example—are revised.

Revisions to historical data can affect the calculations of forecast errors. For example, the RMSE of CBO's two-year forecasts of the growth of real output is 1.2 percentage points if calculated using the data that were available immediately after the two-year horizon of each forecast. But the RMSE is 1.3 percentage points if the most recently available data are used in the calculation.

12. For a similar approach to measuring uncertainty that uses the RMSE, see David Reifschneider and Peter Tulip, *Gauging the Uncertainty of the Economic Outlook Using Historical Forecasting Errors: The Federal Reserve's Approach*, Finance and Economics Discussion Series Paper 2017-020 (Board of Governors of the Federal Reserve System, February 2017), https://doi.org/10.17016/FEDS.2017.020 (PDF, 404 KB). For a visual representation of the uncertainty in CBO's forecasts of real gross domestic product, see Congressional Budget Office, *The Budget and Economic Outlook: 2017 to 2027* (January 2017), Figure 2-11, www.cbo.gov/publication/52370.

13. For further discussion of why CBO assumes that current laws generally remain in place when preparing its economic forecasts, see Congressional Budget Office, *What Is a Current-Law Economic Baseline?* (June 2005), www.cbo.gov/publication/16558.

14. Different assumptions about monetary policy can also make it difficult to compare CBO's forecasts with other forecasts. CBO assumes that monetary policy will reflect the economic conditions that the agency expects to prevail under the fiscal policy specified in current law.

Table 1.

Summary Measures for Two-Year Forecasts

Percentage Points

	CBO	Administration	*Blue Chip* Consensus
		Output	
Growth of Real Output (1980–2014)			
Mean error	-0.1	0.2	*
Mean absolute error	1.0	1.2	1.1
Root mean square error	1.3	1.5	1.4
Growth of Nominal Output (1980–2014)			
Mean error	0.2	0.5	0.4
Mean absolute error	1.1	1.3	1.1
Root mean square error	1.5	1.7	1.5
		Inflation	
Inflation in the CPI (1981–2014)			
Mean error	0.2	0.1	0.3
Mean absolute error	0.7	0.7	0.8
Root mean square error	0.9	0.9	1.0
Difference Between Inflation in the CPI and the Output Price Index (1981–2014)			
Mean error	-0.1	-0.2	-0.1
Mean absolute error	0.3	0.4	0.4
Root mean square error	0.4	0.6	0.4
		Interest Rates	
Interest Rate on 3-Month Treasury Bills (1981–2014)			
Mean error	0.6	0.2	0.5
Mean absolute error	0.9	1.0	1.0
Root mean square error	1.3	1.3	1.2
Real Interest Rate on 3-Month Treasury Bills (1981–2014)[a]			
Mean error	0.3	0.1	0.2
Mean absolute error	1.0	1.1	1.0
Root mean square error	1.2	1.4	1.4
Interest Rate on 10-Year Treasury Notes (1984–2014)			
Mean error	0.4	0.2	0.5
Mean absolute error	0.7	0.8	0.7
Root mean square error	0.7	0.9	0.8
		Wages and Salaries	
Growth of Wages and Salaries (1980–2014)			
Mean error	0.4	0.7	b
Mean absolute error	1.3	1.5	b
Root mean square error	1.8	2.0	b
Change in Wages and Salaries Measured as a Percentage of Output (1980–2014)			
Mean error	0.1	0.1	b
Mean absolute error	0.4	0.4	b
Root mean square error	0.5	0.5	b

Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Bureau of Economic Analysis; Bureau of Labor Statistics; Federal Reserve.

Forecast errors are projected values minus actual values; thus, a positive error is an overestimate. The mean error is the arithmetic average of the forecast errors. The mean absolute error is the average of the errors with the negative signs removed from the underestimates. The root mean square error is calculated by squaring the forecast errors, averaging those squares, and taking the square root of that average.

Date ranges refer to the years in which the forecasts were made. For details on the data underlying the summary measures presented here, see the appendix.

Output is either GDP or (before 1992) GNP. Real output is nominal output adjusted to remove the effects of inflation.

CPI = consumer price index; GDP = gross domestic product; GNP = gross national product; * = between –0.05 percentage points and zero.

a. The real interest rate is the nominal interest rate deflated by the projected rate of growth in the CPI.

b. The *Blue Chip* consensus does not include forecasts of wages and salaries.

Researchers have found that in some cases, such as when comparing the performance of models over time, it may be more appropriate to use earlier estimates of data than to use the more recent updates.[15]

Data revisions also make it difficult to identify the source of forecast error. For example, BEA made several downward revisions to estimates of real GDP growth during the 2007–2009 recession (see Figure 3). When CBO prepared its baseline forecast in January 2009, real GDP had reportedly fallen by an annualized rate of 0.5 percent during the third quarter of 2008; however, revised data now show a 1.9 percent drop that quarter. Similarly, the latest revisions show that average annual growth of real GDP was nearly one-half of a percentage point lower during the recession than BEA initially reported in January 2010. Had CBO and other forecasters known the true state of the economy at that time, their projections probably would have been different. It is therefore difficult to identify how much of the forecast error (measured using current data) is due to the fact that forecasters based their projections on contemporary data that has since been revised and how much of the error is attributable to other sources, such as unforeseen economic developments.

Changes to definitions and methods also affect the comparability of current versions of historical data series with past forecasts. For example, business and government spending on computer software was once treated as spending for an intermediate good—that is, an input into the production process—and thus did not count as a component of GDP. But in 1999, BEA reclassified such spending as investment. That same year, BEA adopted new methods for calculating the price indexes for various categories of consumption. Largely as a result of those changes, BEA increased its estimates of growth in real GDP for the 1980s and 1990s. In particular, BEA's estimates of average annual growth in real GDP from 1992 to 1998 rose by 0.4 percentage points, and inflation in the GDP price index for those years was revised downward by 0.1 percentage point per year.[16] Forecasters cannot anticipate such changes when making their projections; they rely on the definitions and methods that exist at the time.

Some Sources of Forecast Error

Forecast errors often stem from the difficulties of anticipating three key economic developments—turning points in the business cycle, changes in productivity trends, and changes in crude oil prices.

Turning Points in the Business Cycle

Turning points—peaks and troughs in the business cycle—mark the beginning and end of recessions, which are periods of significant contraction in economic activity. Between 1976 and 2014, the years covered in this evaluation, there were five recessions—in 1980, from 1981 to 1982, from 1990 to 1991, in 2001, and from 2007 to 2009. CBO's, the Administration's, and *Blue Chip*'s forecasts of the growth of real output made around each recession since 1981 were substantially less accurate than those made in other years (see Figure 4).

Forecast errors tend to be large around business cycle peaks for a number of reasons. First, recessions are sometimes prompted by events or shocks that forecasters cannot predict. For example, in August 1990, the Iraqi invasion of Kuwait led to a spike in oil prices and a drop in consumer confidence, which probably contributed to the recession that followed.

Another reason errors in forecasts made near the start of a recession tend to be larger is that economists cannot be sure that a recession has begun until sufficient data are available, typically many months after the fact. For example, the Business Cycle Dating Committee of the National Bureau of Economic Research did not announce the December 2007 business cycle peak until 11 months later. For that reason, forecasters may not account for a recession in their projections even after it has started because they may not yet be aware of it.

Further complicating the forecasting process is that turning points in the business cycle often occur during periods of high uncertainty. For example, in January 2008, one month after the business cycle peak, CBO reported, "The economic outlook this year is particularly vulnerable to uncertainty about the degree to which

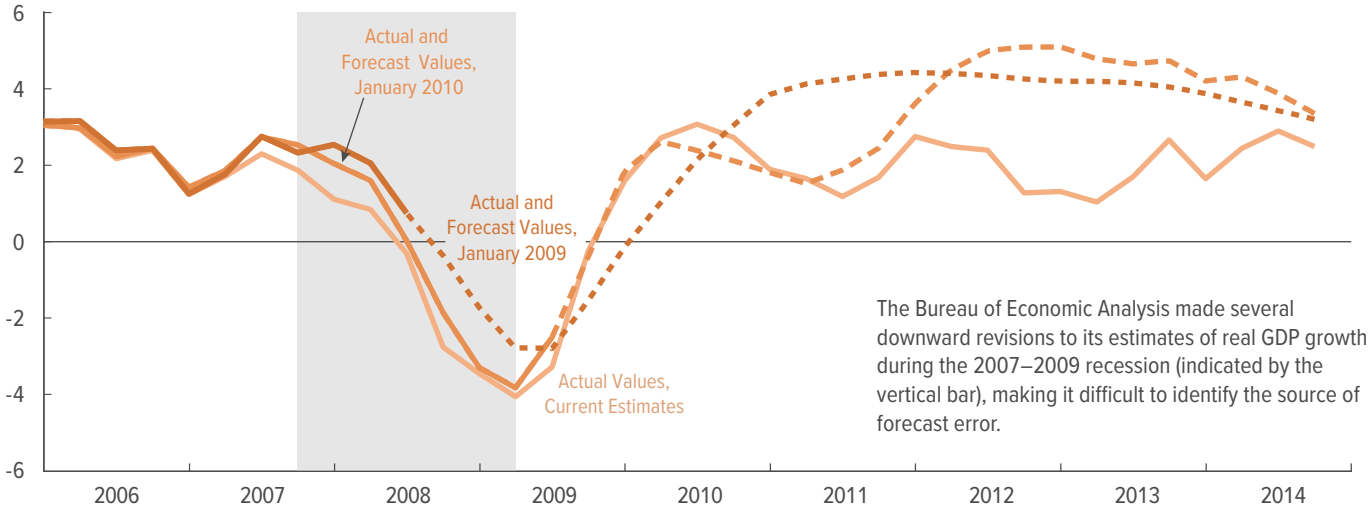
15. See, for example, Tom Stark and Dean Croushore, "Forecasting With a Real-Time Data Set for Macroeconomists," *Journal of Macroeconomics*, vol. 24, no. 4 (December 2002), pp. 507–531, https://doi.org/10.1016/S0164-0704(02)00062-9.

16. See Eugene P. Seskin, "Improved Estimates of the National Income and Product Accounts for 1959–98: Results of the Comprehensive Revision," *Survey of Current Business* (December 1999), pp. 15–43, www.bea.gov/scb/pdf/national/nipa/1999/1299niw.pdf (PDF, 392 KB).

Figure 3.

CBO's Forecasts and Actual Growth Rates of Real GDP

Percentage Change From Previous Year



Sources: Congressional Budget Office; Bureau of Economic Analysis.

Solid lines represent the estimates of actual values that were available at the time each forecast was prepared. Dashed lines represent forecast values.

Real GDP is nominal GDP adjusted to remove the effects of inflation.

Data are quarterly and are plotted through the fourth quarter of 2014.

GDP = gross domestic product.

the problems in the housing and financial markets will spill over to affect other sectors of the economy. Growth in 2008 could be weaker than CBO expects if the turmoil in the financial markets leads to a more severe economy-wide curtailment of lending than CBO anticipates."[17] Under such uncertain conditions, widely different outcomes can appear equally probable, making it difficult to gauge whether an economic downturn is imminent.

Finally, the nature of business cycles has changed over time. Until the early 1990s, the U.S. economy typically grew rapidly for several quarters after a recession ended. Since then, however, recoveries have been much slower. Failing to anticipate the changing nature of business cycles has been one source of forecast error.

Changes in Productivity Trends

Forecasts of productivity growth play a critical role in forecasting potential output, which is an estimate of the maximum sustainable level of production. CBO's forecast of potential output is a measure of how much the economy can sustainably grow during periods of expansion and determines the trajectory of GDP in the later years of the agency's 10-year forecasts.

Labor productivity is the average real output per hour of work. Thus, by definition, real output equals labor productivity times the total number of hours worked. The following are some of the sources of growth in labor productivity:

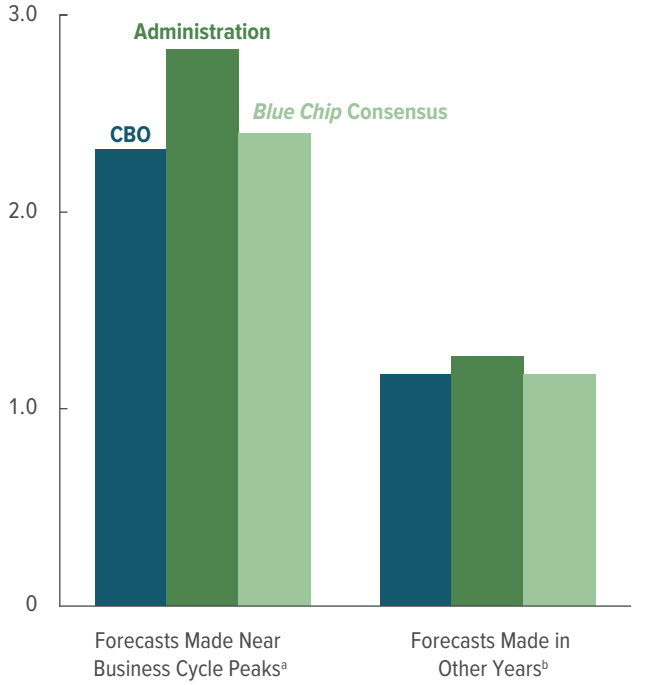
- Capital accumulation (the change in the amount of equipment, structures, software, and infrastructure in use),
- Education and skills development (also called investment in human capital), and
- Innovation (the greater efficiency achieved through better tools, systems, or methods).

17. Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2008 to 2018* (January 2008), p. 21, www.cbo.gov/publication/41661.

Figure 4.

Root Mean Square Errors of Two-Year Forecasts of the Growth of Real Output Made Near Business Cycle Peaks

Percentage Points



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Bureau of Economic Analysis.

Real (inflation-adjusted) output is either real GDP or (before 1992) real GNP.

Forecast errors are projected values minus actual values. The root mean square error is calculated by squaring the forecast errors, averaging those squares, and taking the square root of that average.

GDP = gross domestic product; GNP = gross national product.

a. Calculations are for forecasts made near business cycle peaks—those published in 1981, 1990, 2001, and 2008.

b. Calculations are for all forecasts made between 1981 and 2014 except for the four made near business cycle peaks.

When forecasting productivity growth, CBO considers historical trends in capital accumulation, educational attainment, and the effects of public policy on incentives to invest. Shifts in such trends may be difficult to identify until several years after the fact. Consequently, forecasters may make incorrect inferences about the trajectory of productivity growth and, therefore, potential output growth.

Since the early 1970s, there have been three shifts in the trend of productivity growth—in 1973, 1996, and 2005 (see Figure 5). When the recession began in late 1973, labor productivity growth in the nonfarm business sector dropped precipitously. Whereas productivity had previously grown at a rate of 2.7 percent per year, it grew by only about 1.5 percent per year through the mid-1990s. At least in part because most forecasters in the 1970s expected that the productivity trend of the previous decades would prevail, their forecasts of real output in the mid- to late 1970s turned out to be too optimistic. That expectation also helps explain why forecasters repeatedly underestimated inflation in their projections for the late 1970s.

In 1996, growth in labor productivity in the nonfarm business sector accelerated, averaging more than 3 percent per year for nearly a decade. For several consecutive years, forecasters underestimated the trend of productivity growth, which partly explains why their projections of the economy's growth rate were too low and their projections of inflation in the output price index were too high.[18] The acceleration in labor productivity stemmed from a pickup in technological progress (especially in information technology) and an increase in the amount of capital per worker as firms invested heavily in the new technology.

Since 2005, the growth of labor productivity has been noticeably slower than it was previously for reasons that are not fully understood. The slowdown partly reflects cyclical factors related to the severe recession that occurred from 2007 to 2009 and the ensuing weak recovery. In addition, the growth of the labor force decelerated, which in turn slowed the growth of capital services and possibly reduced the rate at which businesses could bring new technologies into the production process. Some research suggests that such problems might be exacerbated by other, longer-term structural problems that might be impeding the rate at which new technologies diffuse through industries.[19] The unexpected

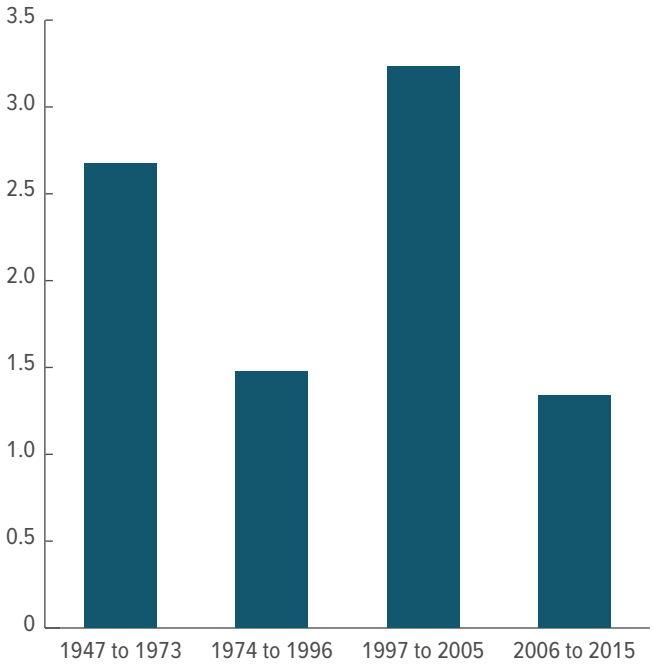
18. See Spencer Krane, "An Evaluation of Real GDP Forecasts: 1996–2001," *Economic Perspectives*, vol. 27, no. 1 (Federal Reserve Bank of Chicago, 2003), pp. 2–21, http://tinyurl.com/y8wadllm; and Scott Schuh, "An Evaluation of Recent Macroeconomic Forecast Errors," *New England Economic Review* (Federal Reserve Bank of Boston, January/February 2001), pp. 35–56, http://tinyurl.com/ych7zk8d.

19. See Ryan A. Decker and others, *Declining Business Dynamism: Implications for Productivity?* Hutchins Center Working Paper 23 (Brookings Institution, September 2016), http://tinyurl.com/lv9cs9h; and Dan Andrews, Chiara Criscuolo, and Peter N. Gal, *The Global Productivity Slowdown, Technology Divergence, and Public Policy: A Firm Level Perspective*, Hutchins Center Working Paper 24 (Brookings Institution, September 2016), http://tinyurl.com/km6942w.

Figure 5.

Trends in Labor Productivity

Average Annual Percentage Change



Source: Congressional Budget Office, using data from the Bureau of Labor Statistics.

Data show the average annual growth of labor productivity in the nonfarm business sector. Labor productivity equals real (inflation-adjusted) output divided by the total number of hours worked. The periods shown correspond with the significant shifts in the average annual growth of productivity that occurred in 1973, 1996, and 2005.

slowdown in labor productivity that began in 2005 contributed to forecasters' overestimating interest rates in recent years.

The trend of productivity growth is also one determinant of long-term interest rates. Thus, the difficulties forecasters have had projecting that trend have also contributed to forecasters' persistently overestimating interest rates. Other unanticipated trends, such as the increased foreign demand for Treasury securities and the declining term premium—that is, the compensation that bondholders require for the extra risk associated with holding longer-term securities—also contributed to errors in forecasting interest rates.

Changes in Crude Oil Prices

Prices for crude oil have fluctuated widely over the past 40 years, creating sizable shifts in the price of petroleum imports and sometimes in overall consumer prices (see Figure 6). The effect of those fluctuations on overall inflation largely stems from the fact that crude oil is an important energy source. In the United States, petroleum accounts for more than one-third of total energy consumption.[20]

The reason that there are such large movements in crude oil prices is that producers and consumers have only limited capacity to adjust supply and demand quickly in response to changing market conditions.[21] Fluctuations in oil prices are often difficult to forecast because markets for petroleum products can be sensitive to developments that forecasters cannot reasonably be expected to predict. In particular, sudden price changes have occurred because of political decisions or instability in oil-producing countries. During the 1973–1981 period, for example, oil prices spiked at the time of the oil embargo imposed by the Organization of Arab Petroleum Exporting Countries (1973 to 1974), the Iranian Revolution (1979), and the start of the Iran–Iraq War (1980). Political factors remain a source of uncertainty, but they appear to have become less important in explaining volatility. Recently, oil prices rose steeply leading up to the 2007–2009 recession and fell sharply in 2014 and 2015 because of shifts in global supply and demand as well as technological changes.

In large part, CBO bases its forecasts of oil prices on the prices implied by oil futures contracts, adjusted to account for the agency's forecasts of economic conditions. Although futures markets provide some predictive power, they are imperfect indicators of actual prices in the future.

CBO's Two-Year Forecasts

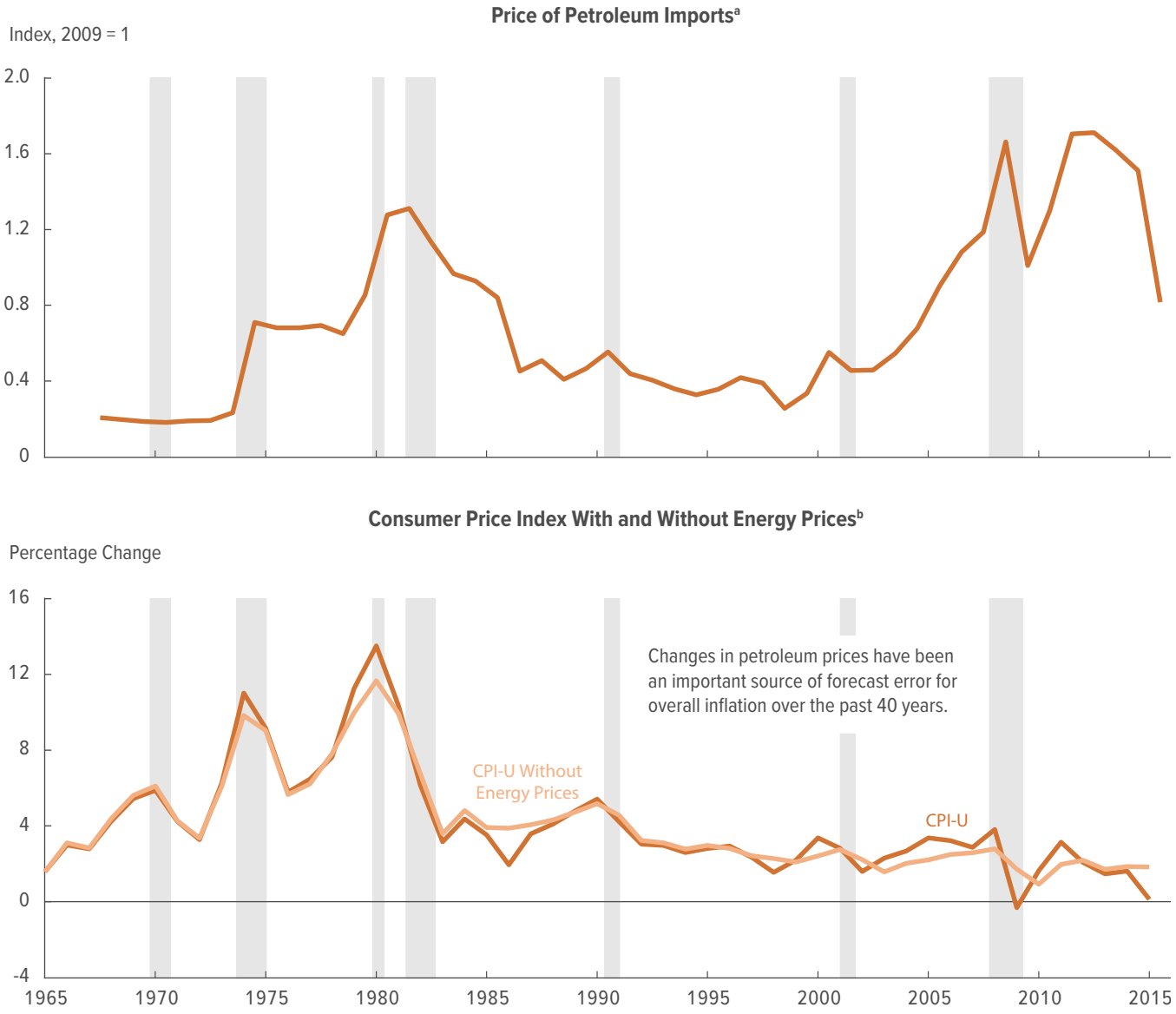
CBO's forecast errors have generally been similar to those of the Administration and the *Blue Chip* consensus. (For a comparison of CBO's two-year forecasts with those of the Federal Reserve, see Box 2 on page 16.) To evaluate the forecasts, CBO looked at various economic indicators, including the growth of output, inflation, interest

20. See Energy Information Administration, *Monthly Energy Review* (January 2017), Table 1.3, https://go.usa.gov/xNFE6 (PDF, 5.48 MB).

21. In the near term, consumers are constrained by the existing energy efficiency of their homes, places of work, and modes of transportation; producers are constrained by their equipment, technology, and the availability and accessibility of natural resources. For further discussion, see Congressional Budget Office, *Energy Security in the United States* (May 2012), www.cbo.gov/publication/43012.

Figure 6.

Price of Petroleum Imports and Consumer Price Inflation



Sources: Congressional Budget Office; Bureau of Labor Statistics; Bureau of Economic Analysis.

The vertical bars indicate the duration of recessions, which extend from the peak of a business cycle to its trough.

Data are annual and are plotted through 2015. The first year for which data on the price of petroleum imports are shown is 1967.

CPI-U = consumer price index for all urban consumers.

a. The price of petroleum imports is the price index for petroleum imports divided by the price index for personal consumption expenditures, excluding prices for food and energy.

b. The major components of energy prices in the CPI-U are motor fuel (which is primarily composed of petroleum products), electricity, and natural gas purchased from utilities.

rates, and changes in wages and salaries (a significant part of taxable income).[22] For most economic indicators, all three sets of forecasts exhibited an upward bias (see Figure 1 on page 2). On average, CBO and the *Blue Chip* consensus slightly underestimated real output growth, and the Administration overestimated it. Compared with the Administration's forecasts, CBO's forecasts of nominal output growth were less biased, but its forecasts of interest rates were more biased. Measured on the basis of the RMSE, CBO's two-year forecasts were about as accurate as the *Blue Chip* consensus (see Figure 2 on page 3). They were also comparable, in terms of accuracy, to the Administration's forecasts, though for some economic indicators, CBO's forecasts were slightly more accurate.

CBO's forecasts of the growth of output (real and nominal) and of inflation show less upward bias than its forecasts of interest rates and of the growth of wages and salaries. However, the output forecasts were less accurate than the forecasts of long-term interest rates, despite the fact that the interest rate forecasts exhibit a sizeable upward bias. Forecaster accuracy is affected by a variety of factors, and indicators are difficult to project for a variety of different reasons. For example, the errors in forecasts of output are particularly sensitive to cyclical movements in the economy, whereas those for inflation are influenced by sudden movements in prices for crude oil.

Output

CBO's forecasts of real and nominal output growth were similar to the *Blue Chip* consensus forecasts in terms of both bias and accuracy; although they were similar to the Administration's forecasts in terms of accuracy, they differed in terms of bias.[23] CBO and the *Blue Chip* consensus underestimated real output growth, on average, whereas the Administration tended to overestimate it. All three forecasters overestimated nominal output growth, on average, but the Administration did so to a greater degree. The accuracy of all three sets of forecasts of the growth of real and nominal output was similar.

Errors in projecting real output growth reveal forecasters' difficulty anticipating turning points in the business cycle and changing trends in productivity growth. Forecasts of nominal output growth are subject to those same difficulties and are affected by errors in projecting inflation as well.

Growth of Real Output. CBO and the *Blue Chip* consensus tended to underestimate the growth of real output, whereas the Administration tended to overestimate it. Nonetheless, the accuracy of all three forecasters was similar. They all tended to significantly overestimate real output around recessions. All three forecasters made their largest forecast errors during the 2007–2009 recession, although CBO did a better job than the other two did of predicting the relative weakness of the recovery that followed (see Figure 7).

Errors in forecasts of real output growth primarily arise from two sources: cyclical movements in the economy and changes in the growth rate of productivity. Cyclical movements are difficult to anticipate, so forecasters typically generate larger errors when the economy is entering a recession. Changes in the trend of productivity growth contribute to persistent misestimates of future real output growth because forecasters are able to detect such changes only well after they have occurred.

In the late 1970s, CBO and the Administration appear to have expected productivity growth to move back toward its earlier post–World War II trend. That expectation contributed to their overly optimistic forecasts of the growth of real output. Early in 1980, CBO, the Administration, and the *Blue Chip* consensus anticipated the coming recession, and consequently, they produced relatively accurate forecasts that year. They did not, however, anticipate that a second recession would follow so soon thereafter. They missed the beginning of the 1981–1982 recession and were unaware of how deep it would be, so the forecasts of real output they made in those two years were too high.

In 1983 and 1984, the economy recovered quickly from the 1981–1982 recession, and real output grew faster than CBO, the Administration, or the *Blue Chip* consensus expected. In forecasts prepared during the 1983–1989 expansion, CBO and the *Blue Chip* consensus underestimated real output growth by roughly 1 percentage point per year, on average; the Administration also underestimated real output growth, but by notably

22. Tables showing the errors of each forecast are available as supplemental material on CBO's website (www.cbo.gov/publication/53090).

23. Before 1992, CBO, the Administration, and the *Blue Chip* consensus forecast output as measured by gross national product (GNP); since 1992, they have forecast output as measured by GDP. Unlike the more commonly cited GDP, GNP includes the income that U.S. residents earn abroad and excludes the income that foreigners earn in this country.

Box 2.

Comparison of CBO's and the Federal Reserve's Two-Year Forecasts

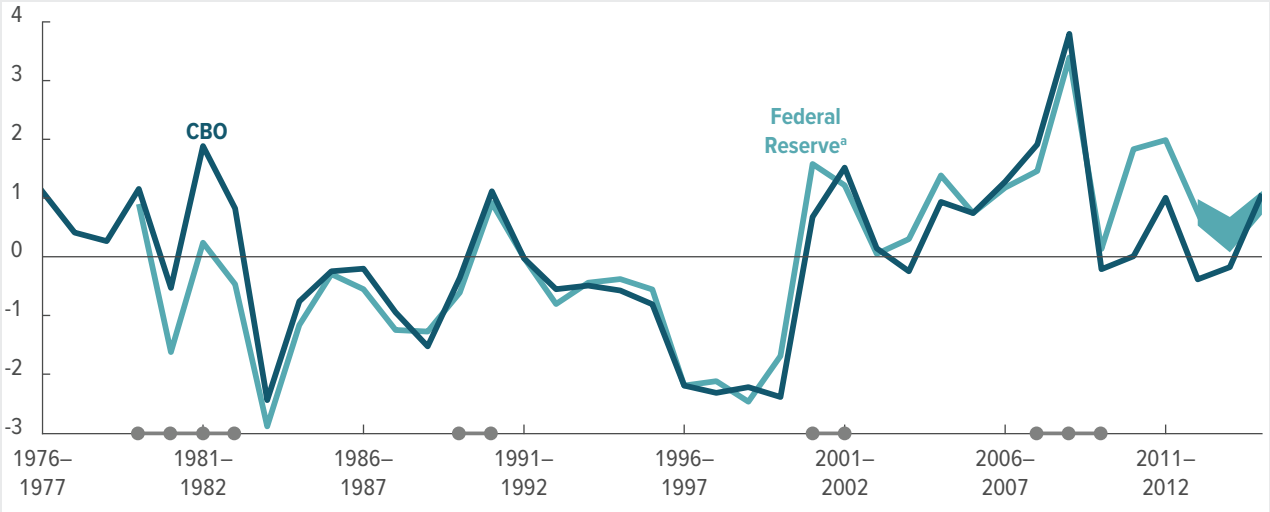
Like the Administration's forecasts and the *Blue Chip* consensus, the Federal Reserve's forecasts provide an informative point of comparison when evaluating the Congressional Budget Office's forecasts. But the Federal Reserve does not release forecasts of Treasury interest rates or of wages and salaries, nor does it publish any five-year forecasts. Therefore, CBO did not include the Federal Reserve's forecasts in the principal analysis for this report. The Federal Reserve does, however, publish timely two-year forecasts of real output growth and inflation rates, which can be compared with CBO's forecasts of those variables.

The Federal Reserve's forecasts differ from CBO's forecasts in two ways.[1] First, the Federal Reserve's forecasts include the effects of anticipated changes in fiscal policy, whereas CBO's forecasts reflect the assumption that current laws governing fiscal policy will remain generally unchanged. Second, the Federal Reserve's forecasts published in recent years are modal forecasts—that is, they represent the single most likely outcome for the economy. By contrast, CBO's forecasts represent the middle of a range of possible economic outcomes. In periods when the range of possible outcomes is highly skewed, the Federal Reserve's forecasts will differ from CBO's. For example, Federal Reserve officials might view the most likely outcome for the economy to be rapid growth, but if there is considerable risk that actual growth might be significantly less than projected, CBO's forecast—represents the middle of the distribution of possible outcomes—might be for slower growth than the Federal Reserve's modal forecast.

CBO's and the Federal Reserve's two-year forecasts of the growth of real output have, for the most part, been similar (see the figure below). The most notable divergences were in forecasts made in the early 1980s and between 2010 and 2012. Before the 1980 recession, CBO produced a fairly accurate forecast of real output growth, whereas Federal

1. For a detailed description of the Federal Reserve's forecasts, see David Reifschneider and Peter Tulip, *Gauging the Uncertainty of the Economic Outlook Using Historical Forecasting Errors: The Federal Reserve's Approach*, Finance and Economics Discussion Series Paper 2017-020 (Board of Governors of the Federal Reserve System, February 2017), https://doi.org/10.17016/FEDS.2017.020 (PDF, 404 KB).

Errors in Forecasts of the Growth of Real Output



Sources: Congressional Budget Office; Federal Reserve; Bureau of Labor Statistics; Bureau of Economic Analysis.

The date ranges on the horizontal axis refer to the two-year forecast period; each forecast was issued in the first year of that period. The dots shown on the horizontal axis indicate that the two-year forecast period overlapped a recession by six months or more.

Forecast errors are projected values minus actual values; thus, a positive error is an overestimate. In the left panel, errors are shown for forecasts of the average annual growth rate of real (inflation-adjusted) output over the two-year forecast period. Output is either GDP or (before 1992) GNP. In the right panel, errors are shown for forecasts of the average annual growth rate of consumer prices over the two-year forecast period. The CPI was forecast through 2011; the price index for personal consumption expenditures has been forecast since 2012. For details on the underlying data, see the appendix.

Continued

Box 2. Continued

Comparison of CBO's and the Federal Reserve's Two-Year Forecasts

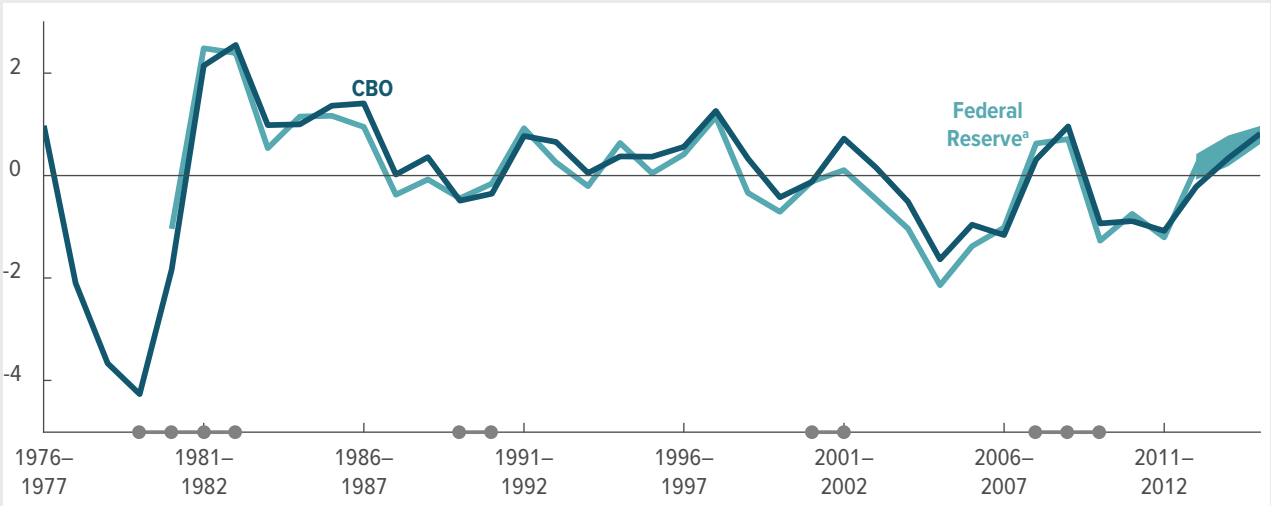
Reserve officials overestimated the depth of the coming recession. However, because CBO failed to anticipate the start of the 1981–1982 recession and, after it had begun, how deep it would be, the agency overestimated growth in real output in its 1981 and 1982 forecasts. Federal Reserve officials more accurately forecast the downturn. In 2010, CBO correctly anticipated that the economic recovery following the 2007–2009 recession would continue to be slow; however, as required by law, the agency assumed that certain tax provisions scheduled to expire would do so and add to fiscal restraint, but those provisions were subsequently extended.[2] By contrast, Federal Reserve officials considerably overestimated growth. The underestimate of output growth in CBO's 2012 forecast reflects, in part, the extension of certain expiring tax provisions, which significantly reduced the amount of fiscal restraint below the amount reflected in CBO's current-law projection. Federal Reserve officials, by contrast, overestimated growth in 2012. In 2013 and 2014, CBO's and the Federal Reserve's forecast errors were similar.

In general, CBO and the Federal Reserve also had similar forecasts of inflation (see the figure below). Forecasts prepared between 2001 and 2005, however, were exceptions. In early 2001, CBO overestimated growth in consumer prices in its two-year forecast, largely because it did not anticipate the 2001 recession. The Federal Reserve's forecast from that year showed little error. Between 2003 and 2005, both forecasters underestimated inflation rates, but the Federal Reserve's errors were somewhat larger. From 2006 to 2011, the two agencies' inflation forecasts were once again similar. For forecasts made between 2012 and 2014, errors in CBO's estimates of inflation were comparable to the smallest errors produced by the Federal Reserve's central tendency—that is, the range of estimates formed by removing the three highest and three lowest estimates made by Federal Reserve officials.

2. When CBO prepared its forecast in early 2010, several tax provisions were set to expire at the end of the calendar year. Most of those provisions were originally enacted in the Economic Growth and Tax Relief Reconciliation Act of 2001 and the Jobs and Growth Tax Relief Reconciliation Act of 2003.

Errors in Forecasts of Consumer Price Inflation

Percentage Points



Beginning with 1986 for inflation and 2012 for output, growth rates are based on the quarterly growth rates over the two-year forecast period.

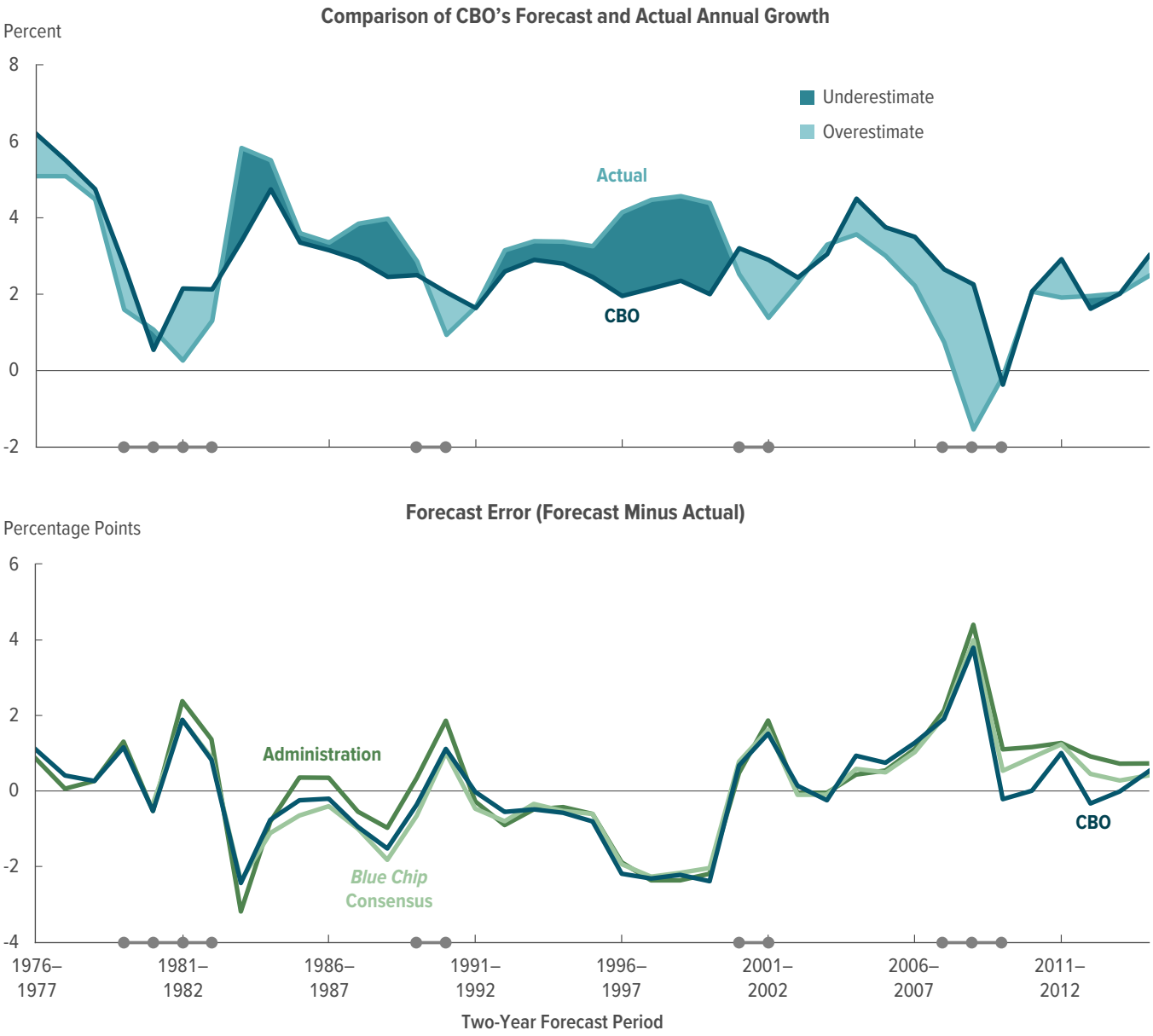
The most recent forecasts included are those published in 2014. The Federal Reserve first published a two-year forecast of real output in 1979 and of consumer prices in 1980.

CPI = consumer price index; GDP = gross domestic product; GNP = gross national product.

a. Forecasts prepared by the staff of the Board of Governors of the Federal Reserve System are reported with a five-year lag and are therefore available only through 2011. For the forecasts made between 2012 and 2014, the shaded area represents the central tendencies of Federal Reserve officials' forecasts—that is, the range of estimates formed by removing the three highest and three lowest forecasts reported by the members of the Board of Governors and the presidents of the Federal Reserve Banks.

Figure 7.

Growth of Real Output: Two-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators;* Bureau of Economic Analysis.

The date ranges on the horizontal axis refer to the two-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the two-year forecast period overlapped a recession by six months or more.

Forecast and actual data show the average annual growth rate of real (inflation-adjusted) output over the two-year forecast period. Output is either GDP or (before 1992) GNP.

The most recent forecasts included are those published in 2014. The first two-year *Blue Chip* consensus forecast of real output was published in 1980.

GDP = gross domestic product; GNP = gross national product.

smaller amounts, particularly during the latter half of the decade.

The 1990–1991 recession resulted in the forecasters' overestimating real output growth in their 1990 forecasts. Even so, the errors by CBO and the *Blue Chip* consensus that year were actually smaller than the RMSEs for the forecasts made between 1980 and 2014. By contrast, the Administration's forecast error that year was considerably larger than its RMSE for the whole period.

In every year between 1992 and 1999, all the forecasters underestimated two-year growth in real output. The errors were particularly large for the two-year forecasts made between 1996 and 1999. About one-fourth of the magnitude of those errors is attributable to subsequent revisions—including important changes to definitions—that BEA made to the national income and product accounts (NIPAs). Those revisions aside, the significant underestimates made between 1996 and 1999 resulted from forecasters' failure to anticipate several important economic developments. One such development was the investment boom of the late 1990s, which increased capital stock and thereby boosted labor productivity and real output more than many forecasters had expected.

When preparing their projections in 2001, forecasters did not anticipate the recession that occurred later that year. CBO and the *Blue Chip* consensus overestimated the growth of real output by similar amounts, and the Administration overestimated it by a slightly larger amount. Following the recession, the economy underwent an unusually slow recovery and weak expansion.

Between 2004 and 2006, all three forecasters' expectations for real output growth proved to be too optimistic; however, the errors in the Administration's forecasts and *Blue Chip* consensus forecasts were smaller than those in the forecasts that CBO made during those years. Perhaps contributing to the overestimates, rising energy prices (unanticipated by many forecasters) dampened the growth of real GDP by roughly a quarter of a percentage point in 2004, by less than half of a percentage point in 2005, and by about a quarter of a percentage point during the first half of 2006.[24]

In 2007 and 2008, forecasters failed to appreciate the effect of the growing imbalances in the housing and financial markets. During the early 2000s, real output growth was partly supported by a boom in residential construction, which was fueled by a growing bubble in house prices. By 2007, a downturn in the housing market was apparent, and tensions in financial markets began to rise. Despite those tensions, in early 2008 forecasters expected that the U.S. economy would avoid falling into recession. For example, in January 2008, CBO stated, "If a severe credit crunch did occur, it would drive the economy into recession by significantly curbing financial activity and consumer spending. However, CBO assumes in its forecast that the Federal Reserve will implement policies to prevent such a crunch and that the financial sector is capable of absorbing most of the losses it faces."[25] Those expectations proved to be incorrect: In 2008, forecasts by CBO, the Administration, and the *Blue Chip* consensus overestimated real output growth by at least 3¾ percentage points.

Despite the unusually weak recovery from the 2007–2009 recession, the two-year forecasts of real output growth that CBO made from 2009 to 2013 were relatively accurate compared with the Administration's projections and the *Blue Chip* consensus forecasts from those years and compared with the agency's own forecasts made over the entire 1980–2014 period. Whereas the Administration and the *Blue Chip* consensus consistently overestimated future growth in real output during the recovery, CBO's projections were relatively close to actual growth, with one notable exception—in 2011, CBO significantly overestimated real output growth, though even then, it did so by less than the other forecasters.

One source of divergence between CBO's forecasts and the other forecasts during the years immediately following the most recent recession was the forecasters' different fiscal policy assumptions. In early 2009, contributors to the *Blue Chip* consensus reported that they expected additional fiscal stimulus, which implied stronger output growth than would be expected under current law.[26] CBO's growth projections were thus tempered by the requirement that its forecasts reflect current law. In the end, fiscal stimulus was weaker than those private forecasters had predicted—as was the underlying momentum in the economy—making CBO's forecast more

24. See Congressional Budget Office, *The Economic Effects of Recent Increases in Energy Prices* (July 2006), p. 6, www.cbo.gov/publication/17984.

25. See Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2008 to 2018* (January 2008), p. 23, www.cbo.gov/publication/41661.

26. See Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2009 to 2019* (January 2009), pp. 10–11, www.cbo.gov/publication/41753.

accurate than the *Blue Chip* consensus. When preparing its forecast in 2010, CBO assumed that expiring tax provisions would result in additional fiscal restraint, but those provisions were subsequently extended.[27]

The forecasts that CBO made in 2012 and 2013 were fairly accurate, especially compared with the Administration's, but in 2014, all forecasters overestimated real output growth by a moderate amount.

Growth of Nominal Output. Differences between errors in forecasts of the growth of real and nominal output reflect inaccuracies in projections of inflation in the output price index. (The two indexes that CBO uses to measure inflation are discussed in the next section.) Because all the forecasters overestimated future inflation, their forecasts of nominal output growth exhibit more upward bias, as measured by the mean error, than do their projections of real output growth. All the forecasters' projections of nominal output growth were slightly less accurate than their projections of real output growth (see Figure 8).

During the 1980s and 1990s, CBO, the Administration, and the *Blue Chip* consensus tended to overestimate inflation, partially offsetting their underestimates of real output growth. Consequently, their forecasts of nominal output growth exhibited less bias over that period than did their forecasts of real output growth.

During much of the 2000s, all the forecasters tended to underestimate inflation rates. Those underestimates generally offset their overestimates of real output growth. However, the forecasts prepared in 2008 were a notable exception. Early that year, all the forecasters expected that a recession would be avoided, and they therefore overestimated both inflation and real output growth. As a result, in that year's forecasts, estimates of nominal output growth were between 4 percentage points and 5 percentage points too high. Since the recession, CBO has slightly underestimated nominal output, on average, because it has underestimated inflation. By contrast, the *Blue Chip* consensus and the Administration's forecasts of nominal output have consistently erred on the high side throughout that same period, mostly because the *Blue Chip* consensus and the Administration anticipated that real output growth would be higher than it was.

Inflation

Inflation is the increase in the average price of a broad basket of goods or services and is measured as the percentage change in a general price index. From 1981 to 2014, inflation forecasts were relatively accurate and exhibited only a small upward bias. But during the unusually volatile period of the late 1970s (before the first full *Blue Chip* consensus forecast was published), CBO and the Administration substantially underestimated inflation. Since the mid-1980s, inflation has stabilized, and forecasting accuracy has improved.

CBO's evaluation of inflation forecasts focuses on two measures: the percentage change in the CPI and the difference between that measure and the percentage change in the price index for output. The CPI measures inflation in the prices of a fixed group of consumer goods and services.[28] The output price index measures the prices of all goods and services that make up GDP (or, before 1992, gross national product [GNP]).

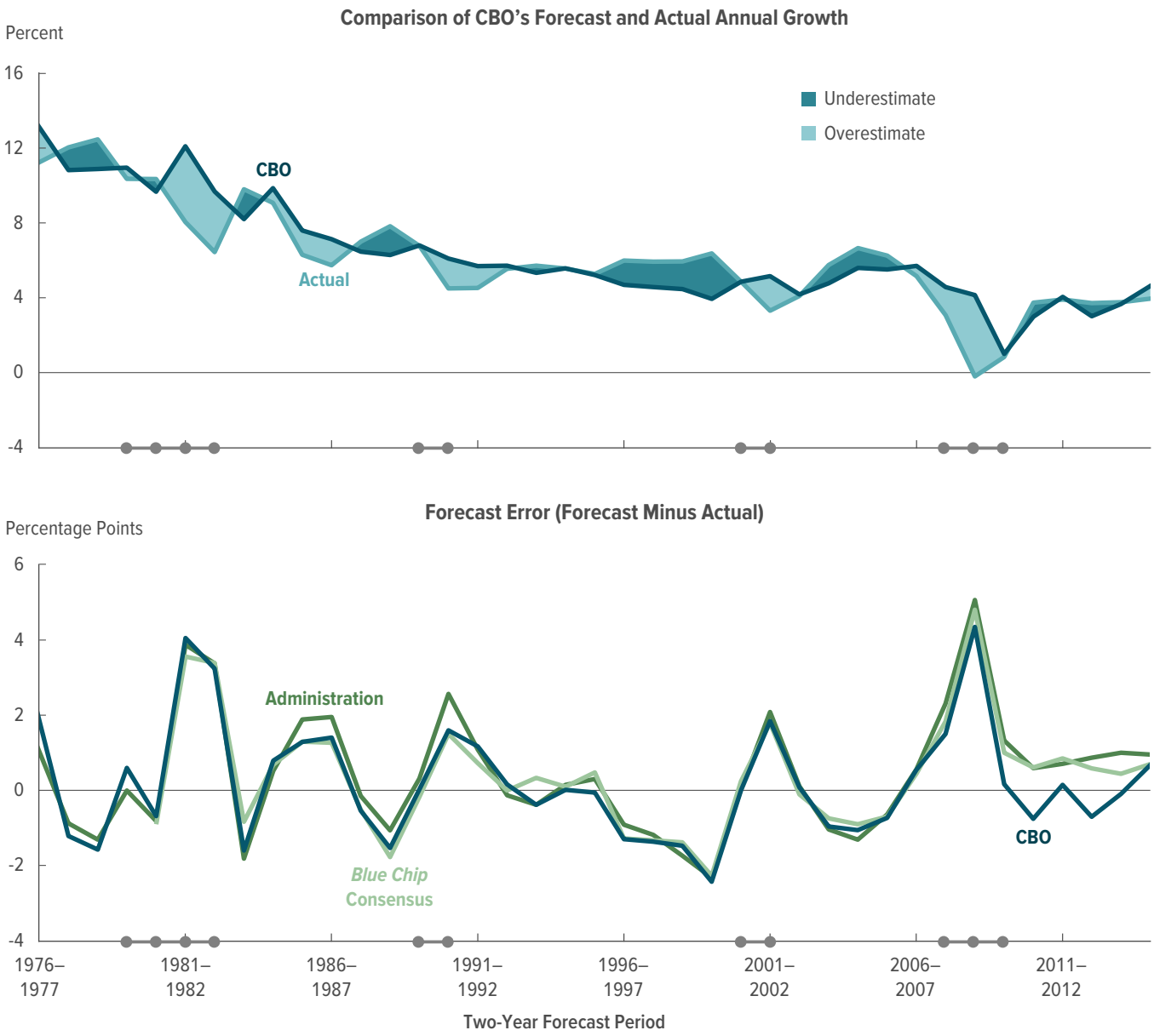
Inflation in the CPI and inflation in the output price index affect federal outlays and revenues differently. All else being equal, higher inflation in the CPI implies faster growth in outlays and slower growth in revenues. Inflation in the CPI increases federal outlays because the index is used to adjust payments to Social Security beneficiaries as well as payments made under other programs, such as civil service retirement. Since the mid-1980s, elements of the individual income tax—including the tax brackets—have also been indexed to the CPI, so inflation in the index reduces revenues. By contrast, growth in the output price index, which is closely linked to growth in nominal income subject to federal taxes, implies faster

27. At the time, several tax provisions—most of which were originally enacted in the Economic Growth and Tax Relief Reconciliation Act of 2001 and the Jobs and Growth Tax Relief Reconciliation Act of 2003—were due to expire at the end of December 2010. See Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2010 to 2020* (January 2010), p. 1, www.cbo.gov/publication/41880.

28. In most of the years examined here, the inflation forecasts are for the CPI-U, which measures inflation in the prices of goods and services consumed by all urban consumers. Some forecasts, however, were for the CPI-W, which measures inflation in the prices of goods and services consumed by urban wage earners and clerical workers. CBO forecast the CPI-W from 1976 to 1978 and again from 1986 to 1989; the Administration forecast the CPI-W through 1991. For the purpose of this evaluation, the distinction between the two measures was most consequential in 1984, when inflation in the CPI-U and CPI-W diverged by 0.9 percentage points.

Figure 8.

Growth of Nominal Output: Two-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Bureau of Economic Analysis.

The date ranges on the horizontal axis refer to the two-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the two-year forecast period overlapped a recession by six months or more.

Forecast and actual data show the average annual growth rate of nominal output over the two-year forecast period. Output is either GDP or (before 1992) GNP.

The most recent forecasts included are those published in 2014. The first two-year *Blue Chip* consensus forecast of nominal output was published in 1980.

GDP = gross domestic product; GNP = gross national product.

growth in revenues. Consequently, if the output price index was forecast to grow more slowly than the CPI, the projected deficit would generally be larger than if the reverse was forecast.

The errors in forecasts of inflation—particularly those of inflation in the CPI—have generally reflected turbulence in crude oil prices. For example, rapidly rising oil prices contributed to forecasters' significantly underestimating inflation when making their projections in the late 1970s and mid-2000s. The dramatic (and largely unexpected) decline in inflation that began during the deep recession in the early 1980s also contributed to errors in inflation forecasts. Forecasters only gradually recognized the extent of that decline and thus drastically overestimated price growth during much of the decade.

Inflation in the CPI. Although errors in forecasts of most economic indicators were largest during recessions, that pattern is not as pronounced for inflation forecasts. After the volatile period of the late 1970s and early 1980s, inflation was relatively stable, and the accuracy of all three sets of forecasts of inflation improved. Errors in inflation forecasts have been relatively small in the past two decades compared with errors in earlier projections of inflation and with those in forecasts of most other indicators.

During the late 1970s, CBO and the Administration made large errors when forecasting CPI inflation (see Figure 9). Primarily because of the spike in crude oil prices in 1979 and 1980, they underestimated inflation in the forecasts they prepared in 1978 and 1979 by about 4 percentage points, on average.

In the forecasts they made between 1981 and 1986, CBO and the Administration overestimated inflation in the CPI by 1.5 percentage points, on average, whereas the *Blue Chip* consensus overestimated it by an average of 1.8 percentage points. The overestimates largely stemmed from the fact that forecasters did not anticipate the sharp and lasting decline in the rate of inflation that followed the 1981–1982 recession. They also did not foresee the drop in crude oil prices that occurred in early 1986.

Between 1987 and 2003, CBO, the Administration, and the *Blue Chip* consensus made relatively small errors: The RMSE of each set of forecasts was roughly one-half of a percentage point. Inflation forecasts probably benefited from the relatively benign economic environment—in contrast to the turbulent late 1970s and early 1980s—that existed during most of that period. Growth in the CPI remained within a narrow range during those years, particularly after 1990.

Between 2004 and 2007, the forecasters persistently underestimated inflation in the CPI, largely because of the unexpected rise in crude oil prices. The two-year forecasts of inflation were about 1 percentage point below actual rates, on average.

In 2008, CBO, the Administration, and the *Blue Chip* consensus failed to anticipate the 2007–2009 recession and the downward pressure that it would place on consumer price growth. As a result, CBO and the Administration overestimated inflation slightly, and the *Blue Chip* consensus overestimated it by a slightly larger amount.

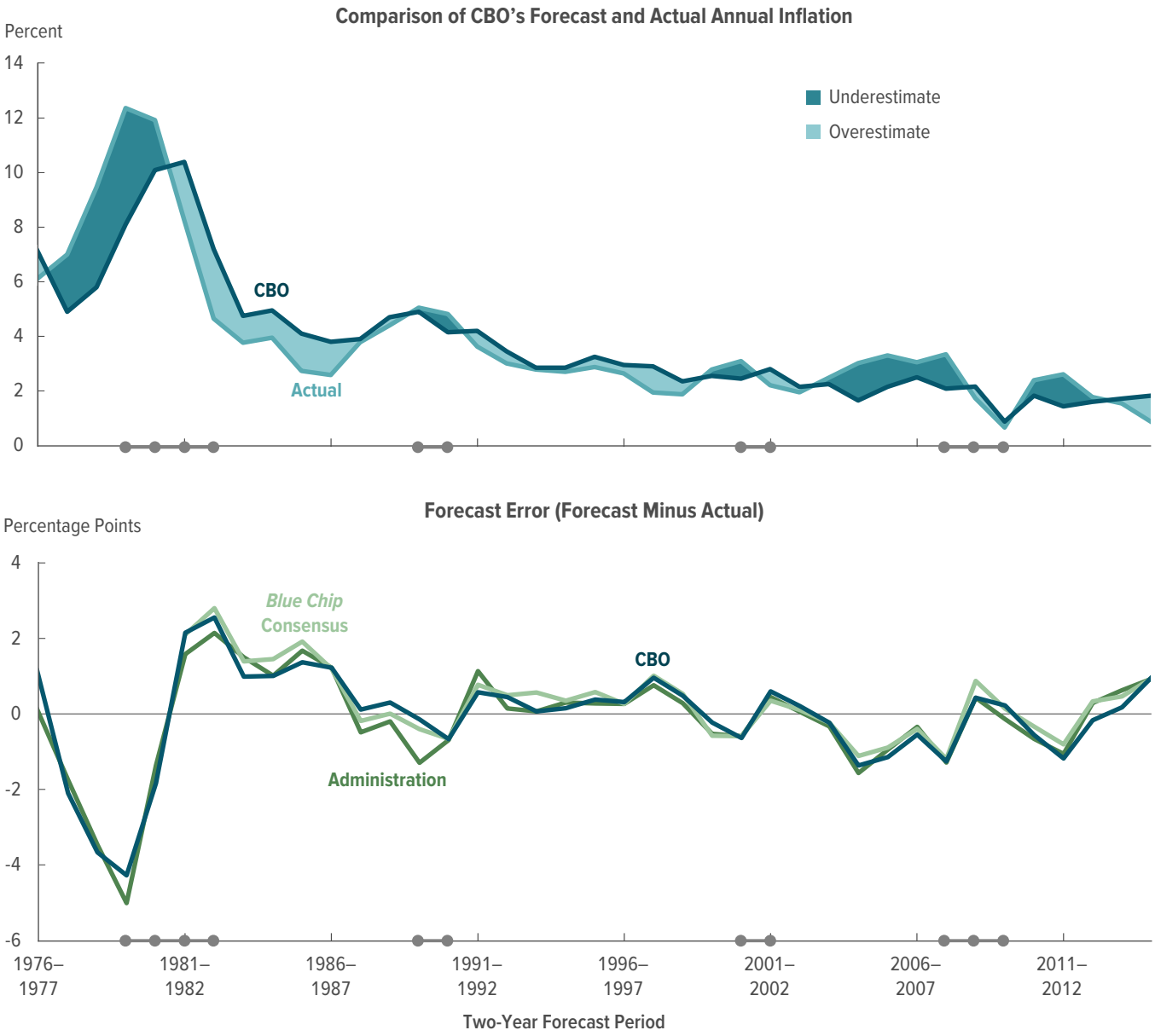
All of the forecasters' 2009 projections showed a decline in inflation close to what actually occurred, but the estimates of inflation in their 2010 and 2011 projections were too low, partly because of an unexpected increase in the price of energy. The inflation forecasts that CBO made in 2012 and 2013 were relatively close to the actual inflation rates. In their 2014 forecasts, CBO, the Administration, and the *Blue Chip* consensus significantly overestimated inflation because of the sudden drop in oil prices that occurred in 2014 and 2015.

Difference Between Inflation Measures. Errors in forecasts of the difference between inflation measures follow a pattern somewhat similar to that of the CPI forecast errors. But because the output price index is more directly related to projections of output than the CPI is, the errors in forecasts of the output price index tend to increase more during recessions than the errors in CPI forecasts do. All three sets of forecasts of the difference between the two measures tended to be too low, meaning that CPI actually grew faster in relation to the output price deflator than projected.

In the forecasts they made between 1978 and 1980, CBO and the Administration underestimated the difference in inflation measures by more than 2 percentage points, on average (see Figure 10). In 1979 and 1980, the difference between inflation in the CPI and the GNP price index spiked to its highest levels since the end of World War II. A significant portion of the divergence can be explained by the oil price shock. A surge in oil prices has a larger effect on the CPI than on the output

Figure 9.

Inflation in the Consumer Price Index: Two-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Bureau of Labor Statistics.

The date ranges on the horizontal axis refer to the two-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the two-year forecast period overlapped a recession by six months or more.

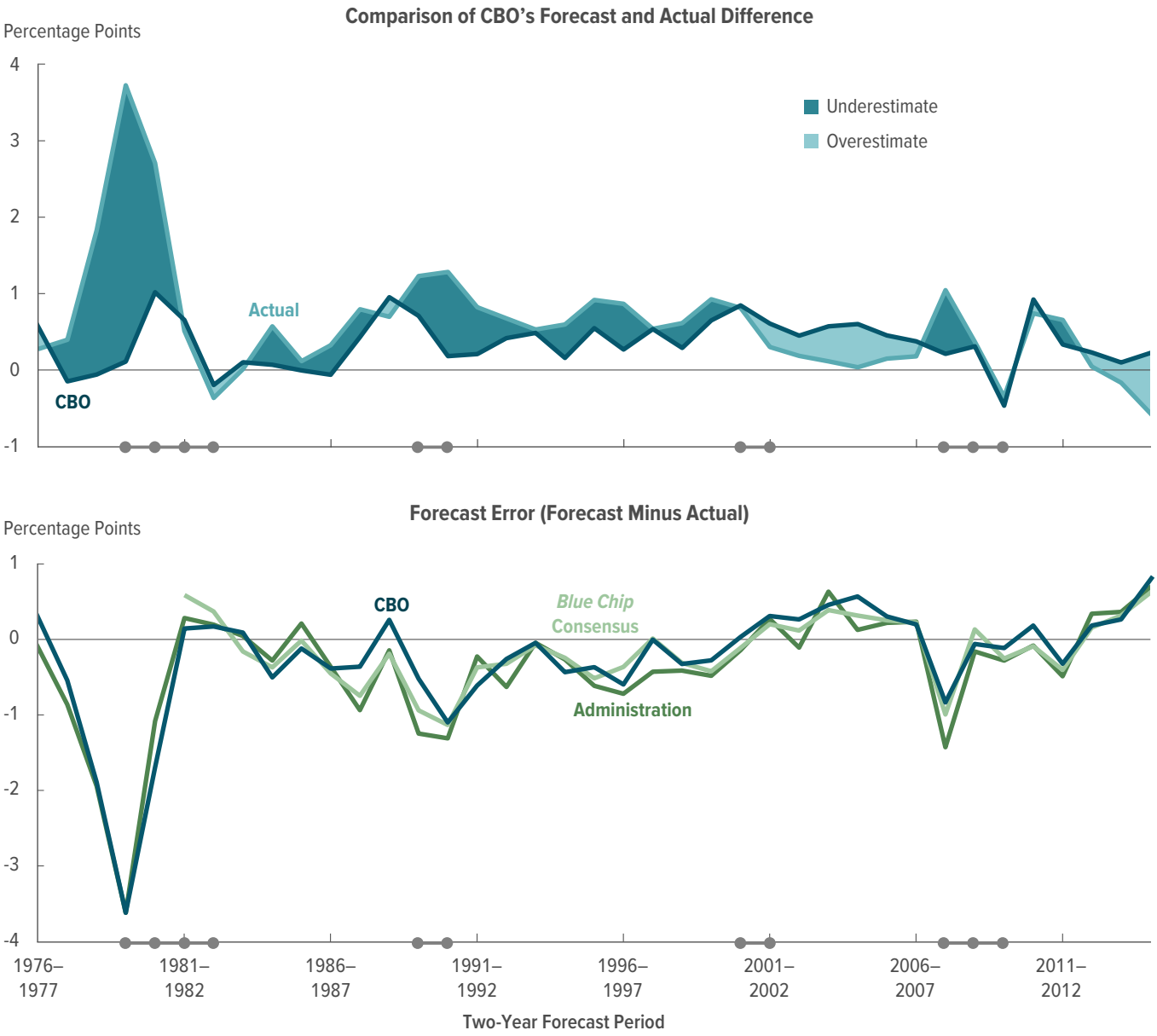
Forecast and actual data show the average annual growth rate of the CPI over the two-year forecast period. Most of the forecasts represented here were for the CPI-U, but some were for the CPI-W. For details on the underlying data, see the appendix.

The most recent forecasts included are those published in 2014. The first two-year *Blue Chip* consensus forecast of the CPI was published in 1981.

CPI = consumer price index; CPI-U = consumer price index for all urban consumers; CPI-W = consumer price index for urban wage earners and clerical workers.

Figure 10.

Difference Between Inflation in the CPI and in the Output Price Index: Two-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Bureau of Labor Statistics; Bureau of Economic Analysis.

The date ranges on the horizontal axis refer to the two-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the two-year forecast period overlapped a recession by six months or more.

Forecast and actual data show average annual growth in the CPI over the two-year forecast period minus average annual growth in the output price index over that period. In most of the forecasts represented here, the CPI-U was projected, but in some, the CPI-W was forecast. The output price index measures the prices of all goods and services that make up either GDP or (before 1992) GNP. For details on the underlying data, see the appendix.

The most recent forecasts included are those published in 2014. The first two-year *Blue Chip* consensus forecast of the CPI was published in 1981.

CPI = consumer price index; CPI-U = consumer price index for all urban consumers; CPI-W = consumer price index for urban wage earners and clerical workers; GDP = gross domestic product; GNP = gross national product.

price index because petroleum products are a much larger share of households' out-of-pocket expenditures than of total output in the economy.

Underestimates of the difference between inflation measures in forecasts made before 2000 partly reflect the methodological change to the national income and product accounts that BEA made in 1999. That year the agency began to treat business and government purchases of software as investment and thus to include such spending in its calculations of GDP. Because the price of software grew much less rapidly, on average, than other prices, the change in the classification of spending on software resulted in a downward revision to the historical data on the growth in the output price index. Hence, the forecasts made before 2000 were based on a pattern of historical growth in the output price index that was higher than such growth is currently reported to have been. That difference probably accounts for about 0.2 percentage points—or two-fifths—of the apparent bias in forecasts from that period.

In 2000, all three forecasters' projections of the difference between the inflation measures were very accurate, but between 2001 and 2006, their forecasts were typically too high. Forecasters did not anticipate the large declines in the difference between the measures that occurred in 2001 and 2002. The declines stemmed from two developments—the slowdown in inflation in energy prices and the reduction in inflationary pressures that followed the 2001 recession. Those two developments caused growth in the CPI to slow more than growth in the output price index through 2002. From 2003 to 2006, forecasters continued to overestimate the difference between the measures.

The sharp increase in the difference between the inflation measures in 2008 caught CBO, the Administration, and the *Blue Chip* consensus by surprise. As a consequence, the absolute values of the errors in their 2007 forecasts were among the largest of the forecast errors since the late 1970s. Despite the volatility in the difference between measures in 2009 and 2010, forecasts made in those years were fairly accurate. Errors were slightly larger in the next three years' forecasts, but not notably so. In 2014, CBO and other forecasters failed to anticipate that the output price index would continue to grow faster than the CPI—an unusual trend that was related to the sudden drop in oil prices in 2014 and 2015.

Interest Rates

Between 1981 and 2014, CBO's and the Administration's projections of interest rates, along with the *Blue Chip* consensus forecasts, were too high, on average. Of the three sets, the Administration's forecasts were the least biased over the period because large negative errors in the forecasts that it prepared in the late 1980s partly offset positive errors in its forecasts from other periods, particularly the 2000s. Measured by the RMSE, CBO's interest rate forecasts were about as accurate as those of the Administration and the *Blue Chip* consensus. The forecasts of interest rates produced by CBO and the *Blue Chip* consensus have, however, tended to be more biased than their forecasts of other economic indicators. In general, forecasters have been surprised by the persistent decline in interest rates over the past three decades.

CBO's forecasts of interest rates on Treasury securities underlie its projections of payments on federal debt and other components of the budget. The forecasts evaluated here are for two key rates—a short-term rate (the rate on 3-month Treasury bills) and a long-term rate (the rate on 10-year Treasury notes).[29] CBO evaluated forecasts of the interest rate on 3-month Treasury bills in both nominal and real terms. The nominal rate of interest is the rate quoted in the secondary market. The real interest rate equals the nominal rate minus inflation in the CPI. Errors in forecasts of the real interest rate reflect errors in forecasts of both the nominal interest rate and the inflation rate.

For forecasts of the 3-month Treasury bill rate, the largest errors have tended to occur during downturns in the business cycle. Short-term interest rates tend to move down when the economy enters a recession. Just as recessions are difficult to anticipate, so too are movements in short-term interest rates. Changes to monetary policy

29. Forecasters have projected different interest rates through the years, so the specific rates used for this evaluation vary slightly in some years. The Administration forecast the rate on newly issued bills through 2000, and the *Blue Chip* consensus forecast the rate from 1982 to 1985 and from 1992 to 1997. In 1981, the only short-term rate available for the *Blue Chip* consensus was the 6-month commercial paper rate. CBO did not forecast the rate on 10-year notes in 1984 or 1985, and the *Blue Chip* consensus did not include forecasts of the rate between 1984 and 1995. However, for the sake of simplicity, this report refers to the rate on 10-year Treasury notes even when discussing those years' forecasts. Forecasts of the Moody's Aaa corporate bond rate were used as a substitute for forecasts of the 10-year Treasury note rate in the years when the Treasury rate was not forecast.

made in response to recessions are a primary contributor to errors in forecasting short-term interest rates. Typically, when the economy enters a recession, inflation falls and unemployment rises, prompting the Federal Reserve to stimulate demand by lowering short-term interest rates.

The errors in forecasting the 10-year Treasury note rate have tended to be less related to turning points in the business cycle than to the gradual and mostly unanticipated decline in long-term interest rates that began in the early 1980s. Several factors have contributed to the decline in long-term interest rates, including slowdowns in labor force and productivity growth and a decline in the term premium.[30]

In addition, changes in expectations of inflation, stronger than anticipated demand for Treasury securities by foreign purchasers, and changes in the amount of federal debt held by the public have contributed to errors in forecasting both short-term and long-term interest rates.

Interest Rate on 3-Month Treasury Bills. Between 1981 and 2014, forecasts of nominal interest rates on 3-month Treasury bills exhibited notable upward bias. CBO and the *Blue Chip* consensus overestimated nominal interest rates, on average; the Administration did as well, but its forecasts had slightly less of an upward bias. In part, that bias stemmed from forecasters' tendency to overestimate inflation rates between 1981 and 1998. All three sets of forecasts were comparable in terms of accuracy; the Administration's forecasts were less biased only because large underestimates in the late 1980s somewhat offset overestimates in other periods. Errors in forecasts of real interest rates follow a pattern similar to that of errors in nominal interest rates, but they are further affected by errors in projecting growth in the CPI. Sometimes the two types of errors worked in opposite directions, making the forecast of the real interest rate more accurate, and sometimes errors in forecasts of growth in the CPI exacerbated errors in forecasts of the nominal interest rate.

In the forecasts they prepared in 1978 and 1979, both CBO and the Administration underestimated the nominal interest rate on 3-month Treasury bills by about 2½ percentage points, on average (see Figure 11). Those errors stemmed entirely from the forecasters' underestimating inflation rates during that period. In fact, CBO and the Administration *overestimated* real interest rates by more than 1¼ percentage points, on average, in those years (see Figure 12). Those overestimates may be the result of the forecasters' overly optimistic projections of real output growth during the period.

During the early 1980s, the Federal Reserve raised interest rates, which contributed to two recessions in close succession and, ultimately, to a sharp and lasting reduction in the rate of inflation. In 1980 and 1981, many forecasters did not fully anticipate that prolonged period of restraint in monetary policy or its impact on price growth. In their 1980 forecasts, CBO and the Administration underestimated both nominal and real interest rates, suggesting that monetary policy proved to be tighter than either expected over the next two years. In 1981, CBO overestimated nominal interest rates, but because it also overestimated inflation, the agency underestimated real interest rates; the Administration and the *Blue Chip* consensus underestimated both nominal and real interest rates that year.

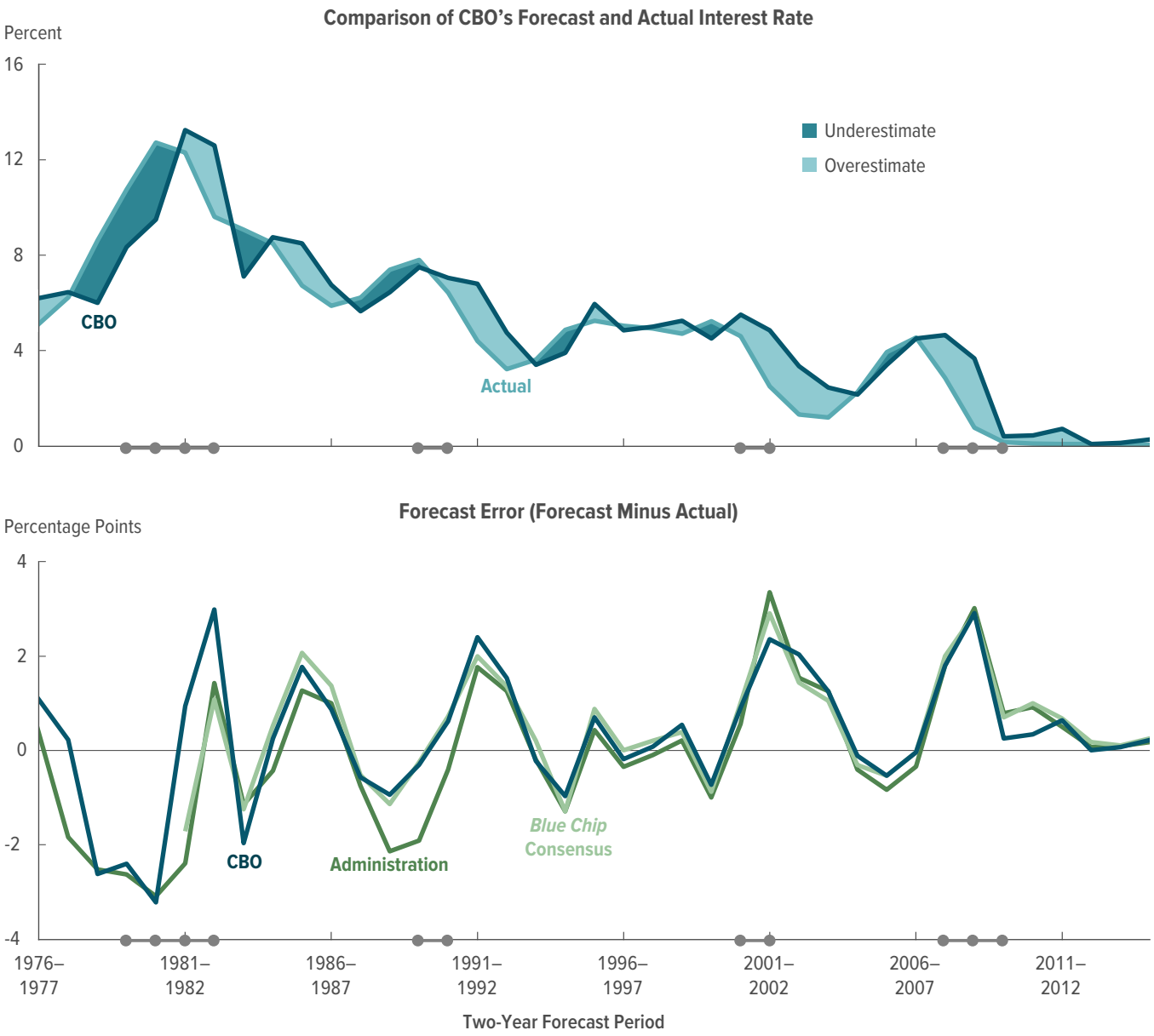
Although all three sets of forecasts were less biased during the rest of the 1980s, they exhibited a notable upward bias after 1990, mainly because in the wake of a recession, forecasters tend to underestimate the extent and duration of the easing of monetary policy. In early 1991 and 1992, forecasters expected interest rates to begin rising as the economy recovered from the 1990–1991 recession, but the recovery was unexpectedly weak, and inflation remained low. In response, the Federal Reserve continued to ease monetary policy for several years, pushing down the nominal interest rate on 3-month Treasury bills from nearly 8 percent in the first half of 1990 to 3 percent in 1993. In the forecasts published between 2000 and 2011, CBO, the Administration, and the *Blue Chip* consensus overestimated real interest rates by more than 1¼ percentage points, on average, and nominal interest rates by slightly less. Some of that bias can be attributed to the 2001 and 2007–2009 recessions and the surprisingly sluggish recoveries that followed them. But some of that bias is due to the largely unanticipated persistent downward trend in interest rates.

CBO's 2012 and 2013 forecasts of negative real interest rates proved to be fairly accurate, but the estimated rate

30. For more on factors contributing to the decline in long-term interest rates, see Congressional Budget Office, *The Budget and Economic Outlook: 2017 to 2027* (January 2017), www.cbo.gov/publication/52370.

Figure 11.

Interest Rate on 3-Month Treasury Bills: Two-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Federal Reserve; Bureau of the Public Debt.

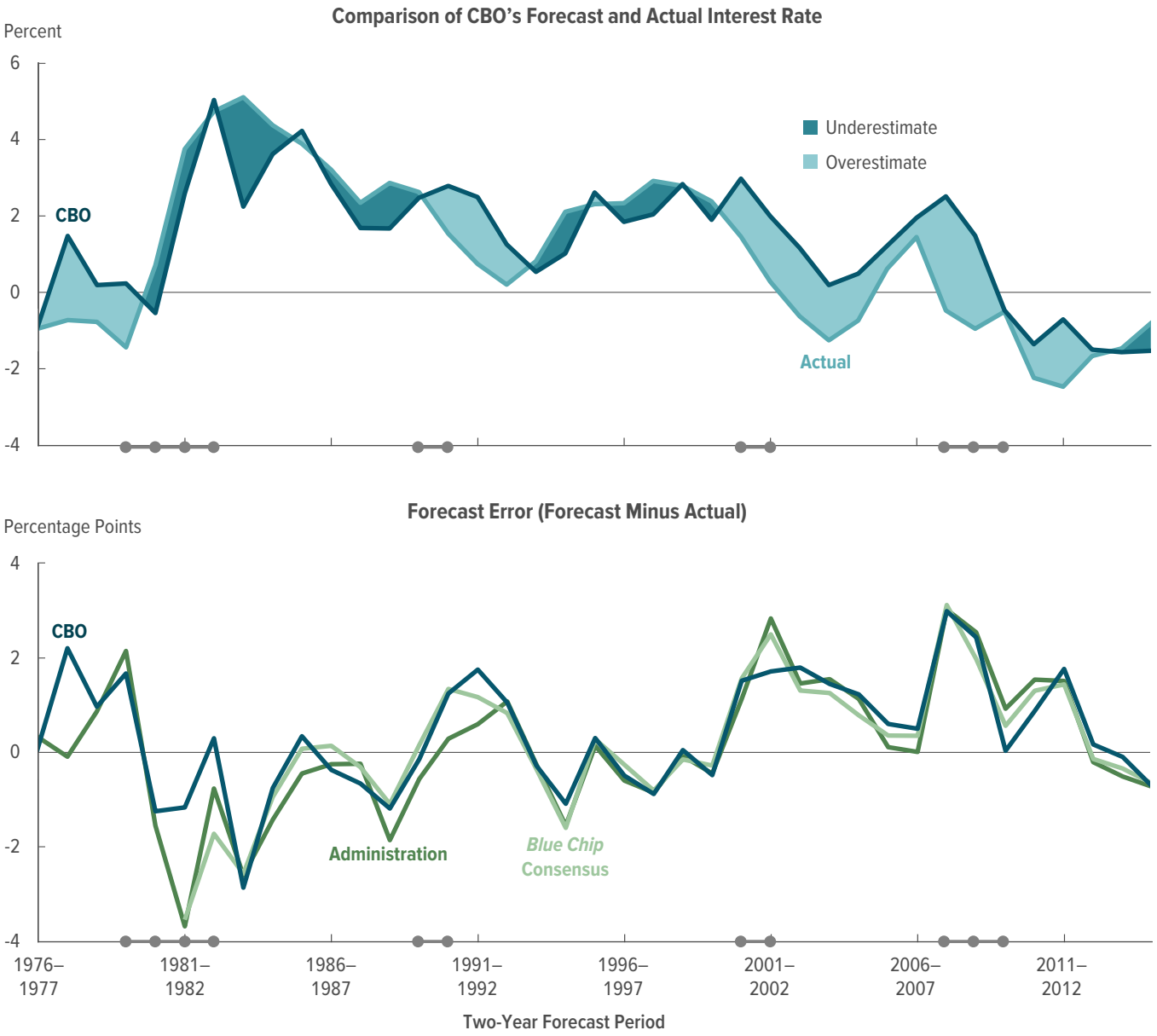
The date ranges on the horizontal axis refer to the two-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the two-year forecast period overlapped a recession by six months or more.

Forecast and actual data show the average annual interest rate over the two-year forecast period. Most of the forecasts represented here were for the secondary-market interest rate, but some were for the rate on newly issued bills or for the 6-month commercial paper rate. For details on the underlying data, see the appendix.

The most recent forecasts included are those published in 2014. The first two-year *Blue Chip* consensus forecast of short-term interest rates was published in 1981.

Figure 12.

Real Interest Rate on 3-Month Treasury Bills: Two-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Bureau of Labor Statistics; Federal Reserve; Bureau of the Public Debt.

The date ranges on the horizontal axis refer to the two-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the two-year forecast period overlapped a recession by six months or more.

Forecast and actual data show the average nominal annual interest rate over the two-year forecast period deflated by the growth in the CPI over that period. Most of the forecasts represented here were for the secondary-market interest rate, but some were for the rate on newly issued bills or for the 6-month commercial paper rate. In most cases, the CPI-U was used as the deflator, but in some, the CPI-W was used. For details on the underlying data, see the appendix.

The most recent forecasts included are those published in 2014. The first two-year *Blue Chip* consensus forecast of short-term interest rates was published in 1981.

CPI = consumer price index; CPI-U = consumer price index for all urban consumers; CPI-W = consumer price index for urban wage earners and clerical workers.

in its 2014 forecast—like the rates in the Administration's forecast and the *Blue Chip* consensus that year—was slightly below the actual rate.

Interest Rate on 10-Year Treasury Notes. Between 1984 and 2014, CBO and the *Blue Chip* consensus tended to overestimate the nominal interest rate on 10-year Treasury notes by similar amounts; the Administration's forecasts were slightly less biased (see Figure 13). Large negative errors in the forecasts that the Administration made in the late 1980s and early 1990s offset positive errors in the forecasts it prepared during other periods, particularly the 2000s. As measured by the RMSE, all the forecasters had a similar degree of accuracy.

Between 2000 and 2008, CBO, the Administration, and the *Blue Chip* consensus persistently overestimated the nominal interest rate on 10-year Treasury notes (by 0.7 percentage points, on average). To some extent, those errors were related to the recessions in 2001 and from 2007 to 2009. However, even during the expansion that occurred between the two recessions, long-term interest rates continued to decline because of slow growth in the labor force, a declining term premium, strong foreign demand for Treasury securities, and, toward the end of that period, a slowdown in productivity growth. All three forecasters were largely surprised by the effect of those trends on interest rates.

By 2009, all of the forecasters had revised their expectations for interest rates downward. For that reason, the forecasts of the rate for 10-year Treasury notes that they made that year were relatively accurate, deviating from actual interest rates by less than one-quarter of a percentage point.

After the 2007–2009 recession ended, forecasters expected long-term interest rates to rise, but they continued to decline over the next two years, especially in 2011. From 2010 to 2012, CBO overestimated the interest rate on 10-year Treasury notes by 0.8 percentage points, on average; the Administration and the *Blue Chip* consensus overestimated that rate by 1.1 percentage points, on average. CBO's 2013 forecast of long-term interest rates was relatively accurate, but the agency's 2014 forecast proved too high when, contrary to expectations, interest rates stayed low.

Wages and Salaries

Between 1980 and 2014, CBO and the Administration overestimated the growth of wages and salaries, on average. (Because the *Blue Chip* consensus does not include forecasts of wages and salaries, only CBO's and the Administration's forecasts are discussed in this section.) CBO's forecasts were less biased than those of the Administration, but that is mostly due to bias in the Administration's forecasts of nominal output growth—both forecasters' projections of wages and salaries measured as a percentage of output were essentially unbiased. The two forecasters' accuracy was similar for projections of the growth of wages and salaries and projections of the change in wages and salaries as a percentage of output. Projections of federal revenues depend significantly on forecasts of wages and salaries, which are a major component of taxable income.[31] Errors in forecasts of wages and salaries may result from inaccurate forecasts of these items:

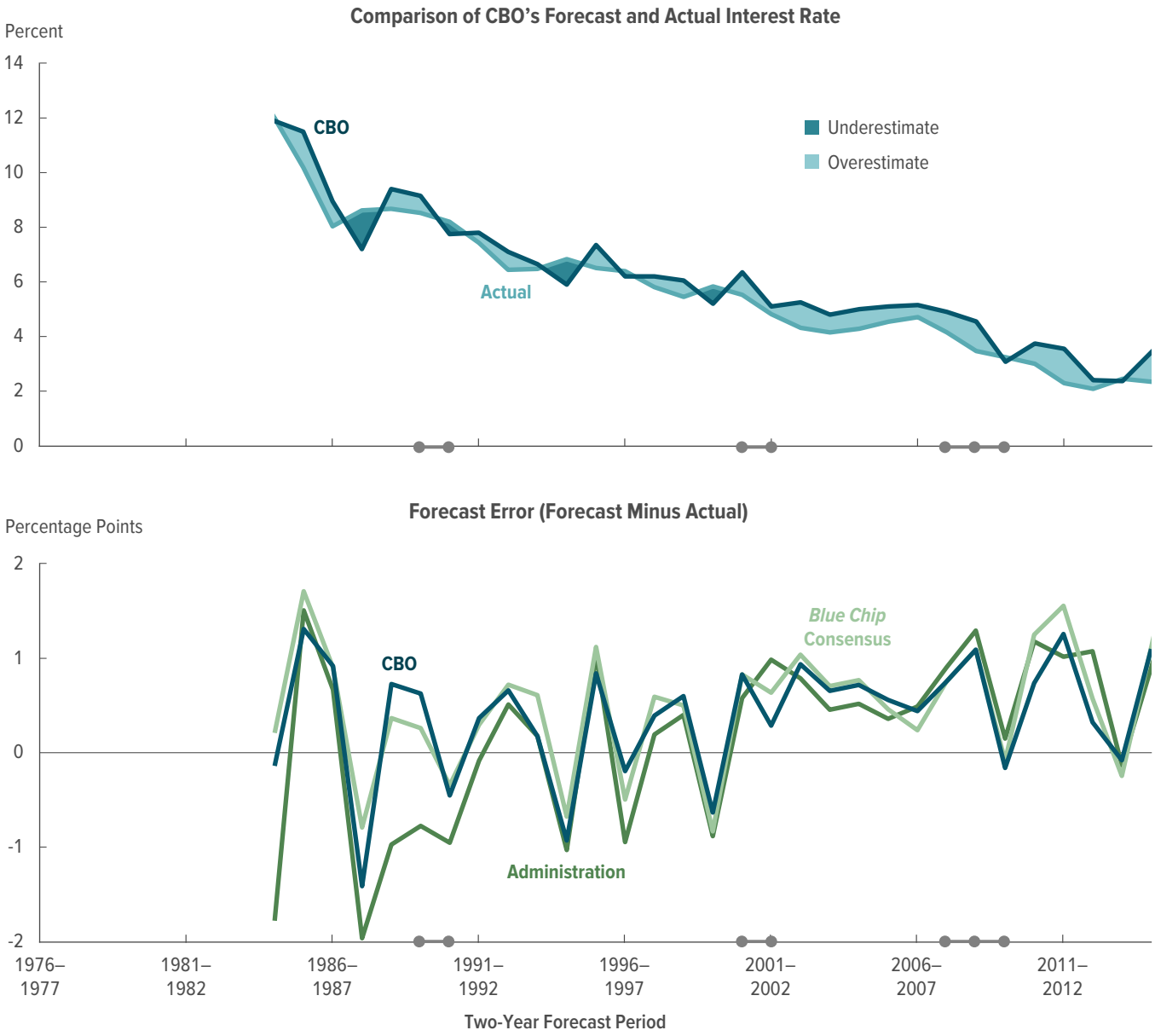
- *Output*. Wages and salaries generally grow with overall economic activity and inflation. A forecaster that failed to anticipate a downturn in output growth would probably overestimate growth in wages and salaries as well.

- *The statistical discrepancy between GDP and gross domestic income* (GDI, the income earned in the production of GDP). In principle, GDP and GDI should be equal, but in practice, they differ because BEA uses a different set of primary sources to estimate each of them. To project GDI, of which wages and salaries is the largest component, forecasters must also project the statistical discrepancy, which is difficult to do because the discrepancy stems from imperfect methods of data collection and estimation. As a result, unexpected swings in the discrepancy may raise or lower wages and salaries in relation to GDP.

31. In some earlier editions of this report, CBO included an analysis of its forecast of a broader category of taxable income: the sum of wages and salaries and corporate book profits. That sum has been dropped from this analysis because legislative changes to the tax rules governing corporations can affect book profits, and they have increasingly done so, which makes it difficult to identify the economic forecast errors. Wages and salaries are less directly affected by legislation.

Figure 13.

Interest Rate on 10-Year Treasury Notes: Two-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Federal Reserve.

The date ranges on the horizontal axis refer to the two-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the two-year forecast period overlapped a recession by six months or more.

Forecast and actual data show the average annual interest rate over the two-year forecast period. CBO did not forecast the interest rate on 10-year Treasury notes in 1984 or 1985, and the *Blue Chip* consensus did not include forecasts of the rate from 1984 to 1995. In those cases, the forecaster's projections of the Moody's Aaa corporate bond rate were used as a substitute.

Data are for forecasts made between 1984 and 2014.

- *Income shares*. Income shares refer to the percentage of each type of income in GDI.[32] Unexpected shifts in the composition of income may cause sizable errors in forecasts of wages and salaries.

Growth of Wages and Salaries. Between 1980 and 2014, CBO and the Administration slightly overestimated the growth of wages and salaries, on average, and the accuracy of their forecasts was similar (see Figure 14). The directions of the errors in the forecasts of the growth of wages and salaries followed a pattern similar to those of the errors in forecasts of nominal output, indicating that the errors stemmed in part from errors in projecting the growth of both real output and prices.

Particularly since 2001, CBO and the Administration have tended to overestimate growth in wages and salaries. To some extent, the fact that forecasters did not anticipate the 2001 and 2007–2009 recessions accounts for that tendency. In addition, starting in the early 2000s, wages began to grow more slowly than productivity. The unexpected departure from the historically close relationship between those two growth rates probably contributed to the overestimates of wage growth since the early 2000s. Both CBO and the Administration also were surprised by the unusually sluggish recovery in wages and salaries relative to output following the two recessions.

Change in Wages and Salaries Measured as a Percentage of Output. To isolate the errors that were unique to the forecasts of wages and salaries, evaluating those forecasts as a percentage of nominal output is helpful (see Figure 15). Two notable historical patterns emerge from such an analysis:

- Measured as a percentage of output, wages and salaries typically move in a cyclical pattern, falling during periods of high unemployment and rising when labor markets tighten.

- Since the early 1970s, wages and salaries have been declining as a percentage of output. In part, that is because employers and employees have substituted untaxed noncash, or fringe, benefits (such as employer-paid health insurance premiums and pension contributions) for taxable wages and salaries.[33] Other factors, such as technological change and globalization, also appear to have contributed to the decline during the past two decades.[34]

Two-year forecasts of the average annual change in wages and salaries measured as a percentage of output that were made over the entire 1980–2014 period exhibited a very small upward bias, but both CBO and the Administration overestimated the change in that percentage by a larger amount after 2000.[35] Both forecasters had a similar degree of accuracy as measured by the RMSE.

During the first half of the 1980s, wages and salaries fell markedly as a percentage of GNP. CBO and the Administration correctly anticipated that decline, but they overestimated the magnitude of the reduction in most years.

Following a slight rebound in the mid-1980s, wages and salaries generally declined as a percentage of output through the early 1990s. To some extent, that decline derived from a large increase in the statistical discrepancy between GDP and GDI—the measure of total output grew faster than the measure of total income during those years. The increase in that discrepancy probably explains why CBO and the Administration tended to overestimate wages and salaries as a percentage of output during the period.

In the late 1990s, wages and salaries grew rapidly as a percentage of GDP, and CBO and the Administration significantly underestimated the magnitude of that growth. Three factors probably contributed to the rise in wages and salaries relative to output:

- The statistical discrepancy between GDP and GDI generally declined during that period because the output measure grew more slowly than the income measure.

32. The types of income included in GDI are wages and salaries, domestic economic profits, employee benefits, proprietors' income, rental income, net interest payments, taxes on production and imports, the surplus of government enterprises, business current transfer payments, and depreciation—all minus subsidies.

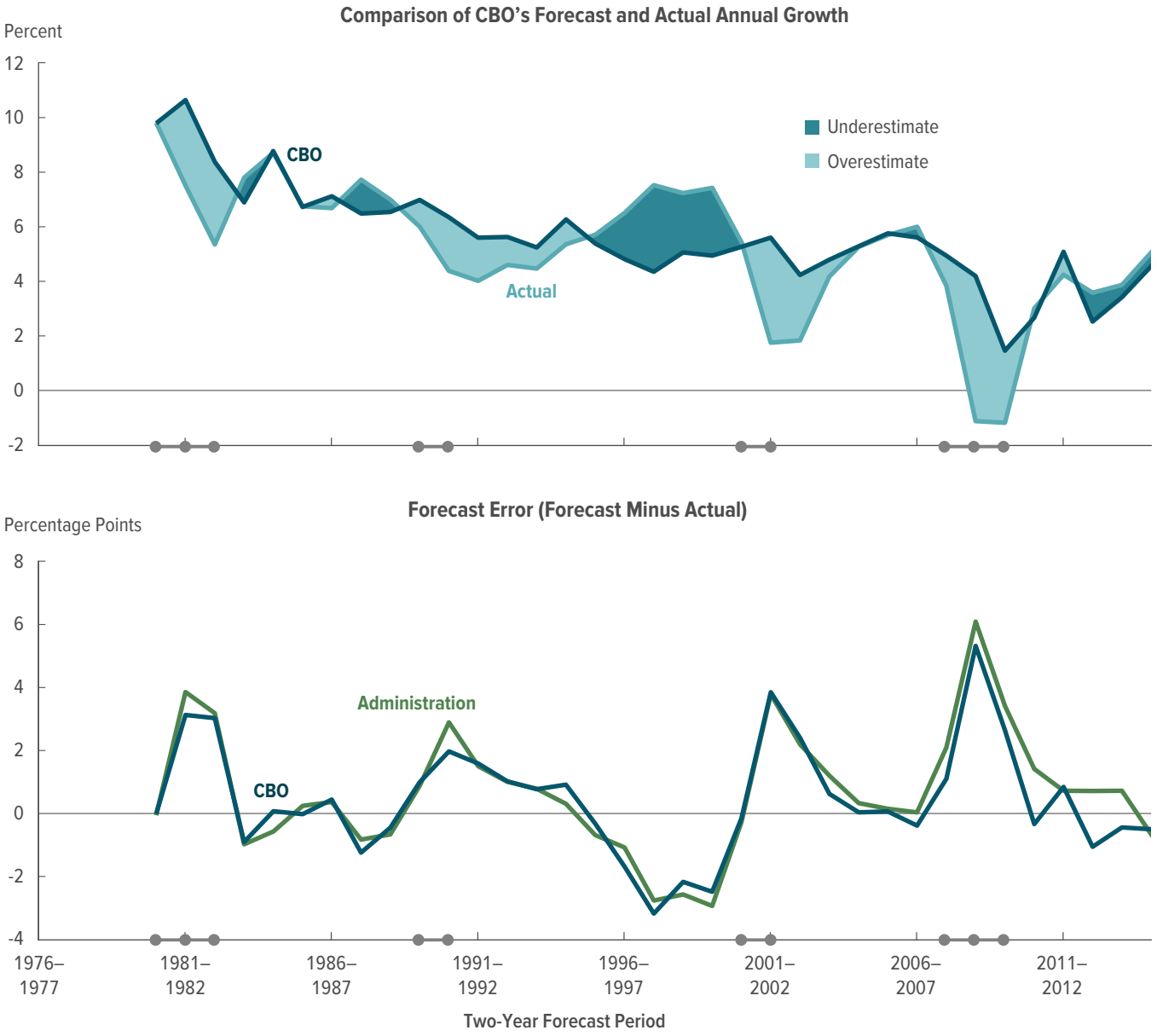
33. For more on employers' contributions to defined-benefit pension plans, see Congressional Budget Office, *The Budget and Economic Outlook: An Update* (August 2005), Box 2-2, pp. 32–33, www.cbo.gov/publication/17091.

34. See Congressional Budget Office, *How CBO Projects Income* (July 2013), p. 15, www.cbo.gov/publication/44433.

35. For forecasts made before 1992, wages and salaries were measured as a percentage of GNP; since 1992, they have been measured as a percentage of GDP.

Figure 14.

Growth of Wages and Salaries: Two-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Bureau of Economic Analysis.

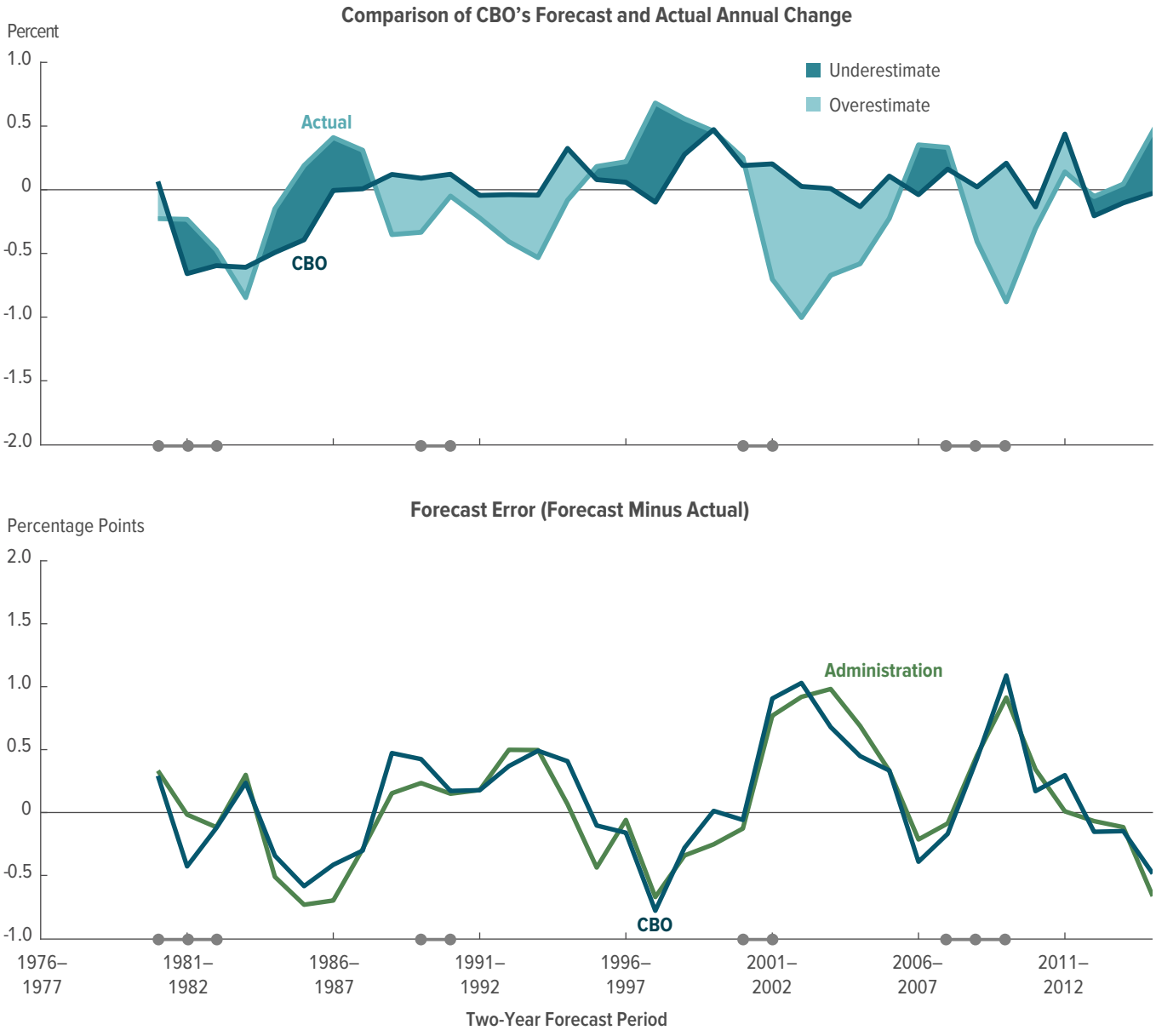
The date ranges on the horizontal axis refer to the two-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the two-year forecast period overlapped a recession by six months or more.

Forecast and actual data show the average annual growth rate of wages and salaries over the two-year forecast period.

Data are for forecasts made between 1980 and 2014. The *Blue Chip* consensus does not include forecasts of wages and salaries.

Figure 15.

Change in Wages and Salaries Measured as a Percentage of Nominal Output: Two-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Bureau of Economic Analysis.

The date ranges on the horizontal axis refer to the two-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the two-year forecast period overlapped a recession by six months or more.

Forecast and actual data show the average annual change in wages and salaries as a percentage of nominal output over the two-year forecast period. Output is either GDP or (before 1992) GNP.

Data are for forecasts made between 1980 and 2014. The *Blue Chip* consensus does not include forecasts of wages and salaries.

GDP = gross domestic product; GNP = gross national product.

- Although labor compensation has increasingly been paid in the form of nontaxable benefits in the years since World War II, that trend was temporarily reversed in the late 1990s as employers' contributions to employees' pension funds and health insurance premiums fell as a share of compensation.[36]

- Employee stock options became more prevalent during the 1990s, and gains from exercising stock options count as wage and salary income in the NIPAs. Changes in wages and salaries as a percentage of GDP generally corresponded to movements in the stock market in those years.[37]

During the first half of the 2000s, forecasters expected wages and salaries measured as a percentage of GDP to either rise or remain roughly unchanged, but instead they fell sharply. In part, the decline resulted from the shift in labor compensation toward nontaxable benefits. The 2001 recession and sluggish recovery in the labor market also contributed to the decline. However, the recession had only modest effects on output growth and the rate of unemployment, so the decline in wages and salaries as a percentage of GDP appears to be unusually large relative to the severity of the recession.

In the forecasts they made between 2008 and 2010, CBO and the Administration underestimated the effects of the severe 2007–2009 recession on wages and salaries relative to GDP. In early 2008, neither forecaster anticipated the onset of the recession, which reduced wages and salaries as a percentage of GDP, so both expected that measure to change very little over the following two years. By early 2009, the recession led both forecasters to significantly lower their projections of real output growth; however, they did not anticipate the effects that slower growth would have on wages and salaries relative to GDP. Toward the end of 2010—in anticipation of tax policy changes scheduled to take effect in 2011 and on the basis of the assumption that fiscal policy would follow current law—CBO overestimated the increase in wages and salaries relative to GDP.[38]

For the forecasts prepared in 2011 and 2012, CBO's errors were slightly larger than the Administration's. In 2011, CBO expected the cyclical rebound in wages and salaries measured as a percentage of GDP to be greater than it actually was, and the next year, it anticipated a slightly larger decline than actually occurred; the Administration's errors were negligible in both years. In the 2013 and 2014 forecasts, CBO and the Administration underestimated the change in wages and salaries as a percentage of output.

CBO's Five-Year Forecasts

As with the two-year forecasts, the five-year forecasts made by CBO and the *Blue Chip* consensus show similar degrees of bias and accuracy, and both sets of forecasts are slightly more accurate than the Administration's forecasts (see Table 2). Although the patterns of accuracy and bias are similar, the five-year forecasts have some characteristics that are distinct from those of the two-year forecasts:

- The five-year forecasts rely more heavily on underlying trends in the economy. CBO, for example, does not usually forecast fluctuations in the economy after the first few years of the projection period. Instead, in the agency's projections, output growth returns to its historical relationship with potential output growth, and other variables move to their estimated long-term values. As a result, errors in five-year forecasts often reveal inaccurate projections of the long-term growth of the economy.

- The five-year forecasts may be less likely to produce large errors that are attributable to relatively brief or small shifts in economic activity. For example,

36. For information about changes in employers' contributions to health insurance during the late 1990s, see David Cutler, *Employee Costs and the Decline in Health Insurance Coverage*, Working Paper 9036 (National Bureau of Economic Research, July 2002), www.nber.org/papers/w9036.

37. See Hamid Mehran and Joseph Tracy, *The Impact of Employee Stock Options on the Evolution of Compensation in the 1990s*, Working Paper 8353 (National Bureau of Economic Research, July 2001), www.nber.org/papers/w8353; and David Lebow and others, *Recent Trends in Compensation Practices*, Finance and Economics Discussion Series Paper 1999-32 (Board of Governors of the Federal Reserve System, July 1999), https://go.usa.gov/xNkbV.

38. In early 2009, CBO's fiscal policy assumptions were consistent with the scheduled expiration of major provisions of the Economic Growth and Tax Relief Reconciliation Act of 2001 and the Jobs and Growth Tax Relief Reconciliation Act of 2003. Those provisions were subsequently extended. The implications for the agency's baseline forecasts of subsequent legislative changes are discussed in Congressional Budget Office, *What Is a Current-Law Economic Baseline?* (June 2005), www.cbo.gov/publication/16558.

Table 2.

Summary Measures for Five-Year Forecasts

Percentage Points

	CBO	Administration	*Blue Chip* Consensus
		Output	
Growth of Real Output (1979–2011)			
Mean error	0.2	0.4	0.1
Mean absolute error	0.9	1.1	0.9
Root mean square error	1.2	1.3	1.1
Growth of Nominal Output (1979–2011)			
Mean error	0.8	0.9	0.9
Mean absolute error	1.1	1.2	1.1
Root mean square error	1.4	1.5	1.4
		Inflation	
Inflation in the CPI (1983–2011)			
Mean error	0.2	*	0.4
Mean absolute error	0.4	0.5	0.5
Root mean square error	0.6	0.6	0.8
Difference Between Inflation in the CPI and the Output Price Index (1983–2011)			
Mean error	-0.2	-0.3	-0.2
Mean absolute error	0.3	0.4	0.4
Root mean square error	0.4	0.5	0.4
		Interest Rates	
Interest Rate on 3-Month Treasury Bills (1983–2011)			
Mean error	1.2	0.8	1.3
Mean absolute error	1.4	1.3	1.5
Root mean square error	1.7	1.7	1.8
Real Interest Rate on 3-Month Treasury Bills (1983–2011)[a]			
Mean error	1.0	0.7	0.9
Mean absolute error	1.4	1.4	1.3
Root mean square error	1.7	1.7	1.6
Interest Rate on 10-Year Treasury Notes (1984–2011)			
Mean error	0.8	0.3	0.9
Mean absolute error	1.0	1.1	1.0
Root mean square error	1.1	1.3	1.1
		Wages and Salaries	
Growth of Wages and Salaries (1980–2011)			
Mean error	1.0	1.2	b
Mean absolute error	1.5	1.6	b
Root mean square error	1.8	1.9	b
Change in Wages and Salaries Measured as a Percentage of Output (1980–2011)			
Mean error	0.1	0.1	b
Mean absolute error	0.3	0.3	b
Root mean square error	0.3	0.3	b

Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Bureau of Economic Analysis; Bureau of Labor Statistics; Federal Reserve.

Forecast errors are projected values minus actual values; thus, a positive error is an overestimate. The mean error is the arithmetic average of the forecast errors. The mean absolute error is the average of the errors with the negative signs removed from the underestimates. The root mean square error is calculated by squaring the forecast errors, averaging those squares, and taking the square root of that average.

Date ranges refer to the years in which the forecasts were made. For details on the data underlying the summary measures presented here, see the appendix.

Output is either GDP or (before 1992) GNP. Real output is nominal output adjusted to remove the effects of inflation.

CPI = consumer price index; GDP = gross domestic product; GNP = gross national product; * = between zero and 0.05 percentage points.

a. The real interest rate is the nominal interest rate deflated by the projected rate of growth in the CPI.

b. The *Blue Chip* consensus does not include forecasts of wages and salaries.

because CBO did not anticipate that a recession would occur later in the year when it made its forecast in early 2001, the agency overestimated the average two-year growth rate of real output by about 1½ percentage points but overestimated the average five-year growth rate by about one-half of a percentage point.

- On the other hand, the error in the five-year forecast prepared in a given year can be larger than the error in the two-year forecast made that same year if a recession occurs after the second year of the forecast period. For example, the two-year forecast of real output growth made in 2005 was relatively accurate because it was unaffected by the recession that began at the end of 2007, just after the forecast period ended. The error in the five-year forecast made that year, however, was over three times as high because it included the effects of that recession.

Output

All the forecasters' five-year projections of output growth (both real and nominal) exhibited similar bias and accuracy. Compared with the two-year forecasts, the five-year forecasts had slightly more upward bias but were roughly as accurate.

Growth of Real Output. Errors in forecasting real output growth over five-year periods are generally due to unexpected shifts in the growth rate of productivity. Recessions and cyclical factors tend to have less of an effect on the longer-term forecasts, although the 2007–2009 recession remains a significant source of error in the five-year forecasts.

In the forecasts they made between 1976 and 1979, CBO and the Administration overestimated the five-year average growth rate of real GNP by more than 2 percentage points, on average (see Figure 16). In part, those errors reflect the slowdown in productivity growth that followed the 1973–1975 recession (see Figure 5 on page 13). Because the forecasters did not expect that slowdown, they overestimated the trend in output growth during the late 1970s. When preparing their forecasts in early 1978 and 1979, CBO and the Administration did not anticipate the two recessions that occurred during the early 1980s, which contributed to the errors made in those forecasts.

The five-year forecasts of the growth of real output that CBO, the Administration, and the *Blue Chip* consensus made during the early 1980s were relatively accurate despite the severe 1981–1982 recession. Real output rebounded very quickly after the recession, so average growth during the recession and the subsequent recovery slightly exceeded the growth projected before the recession. As economic conditions stabilized after the turbulent early 1980s, CBO and the *Blue Chip* consensus made accurate forecasts in the second half of the decade. The Administration, however, slightly overestimated real output growth in those years.

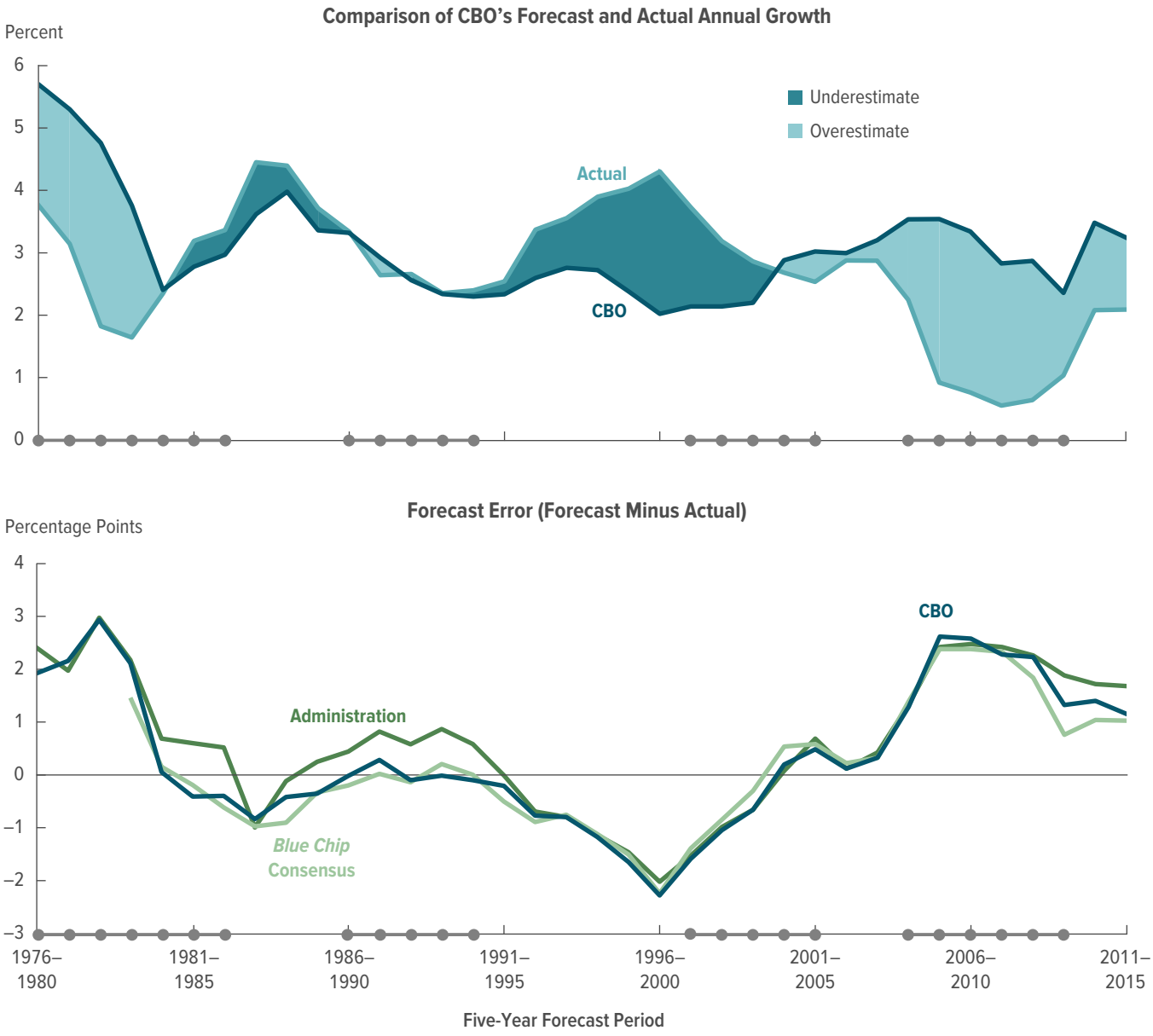
Five-year forecasts of the growth of real GDP made between 1991 and 1999 were too pessimistic. On average, actual growth exceeded all three forecasts' projections of growth by more than a percentage point. Those errors largely resulted from the investment boom of the late 1990s, which increased the capital stock and thereby boosted labor productivity and potential output. Methodological revisions made by BEA in 1999 also contributed to underestimates in forecasts prepared near the end of the period.

In the forecasts they made between 2000 and 2003, CBO, the Administration, and the *Blue Chip* consensus slightly overestimated the five-year average growth rate of real GDP (by less than one-half of a percentage point, on average). A portion of the errors probably stemmed from overestimates of potential output. For example, in early 2002, CBO projected that potential output would grow at an average annual rate of 3.0 percent over the next five years. However, the agency now estimates that potential output grew at an average rate of 2.4 percent per year between 2002 and 2006. That revision reflects an emerging consensus that productivity growth slowed for structural reasons even before the deep recession started at the end of 2007.[39] Because estimates of potential output underpin the medium-term projections, errors in forecasts of potential output carry through to forecasts of other variables.

39. The revisions to CBO's estimates of potential output reflect updated historical data and analytical methods. For further discussion of the sources of those revisions, see Congressional Budget Office, *The Budget and Economic Outlook: 2017 to 2027* (January 2017), pp. 64–65, www.cbo.gov/publication/52370, and *Revisions to CBO's Projection of Potential Output Since 2007* (February 2014), www.cbo.gov/publication/45150.

Figure 16.

Growth of Real Output: Five-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Bureau of Economic Analysis.

The date ranges on the horizontal axis refer to the five-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the five-year forecast period overlapped a recession by six months or more.

Forecast and actual data show the average annual growth rate of real (inflation-adjusted) output over the five-year forecast period. Output is either GDP or (before 1992) GNP.

The most recent forecasts included are those published in 2011. The first five-year *Blue Chip* consensus forecast of real output was published in 1979.

GDP = gross domestic product; GNP = gross national product.

The unexpectedly severe and prolonged effects of the 2007–2009 recession account for most of the errors in the five-year forecasts of real GDP growth that were prepared from 2004 to 2011. Forecasts made between 2005 and 2008, in particular, were much too optimistic. On average, during that period, CBO's and the Administration's forecasts exceeded actual growth by 2.4 percentage points, and the *Blue Chip* consensus forecast exceeded actual growth by 2.2 percentage points.

In the aftermath of the 2007–2009 recession, forecast errors remained high because of the economy's unusually slow recovery. Forecasters expected the pace of the recovery to quicken as it had following most previous recessions. The slowdown in the growth of productivity—which started in the mid-2000s but was not immediately recognized by forecasters—contributed to the sluggish recovery and to forecasters' continuing to overestimate real output growth in 2010 and 2011. CBO was more accurate than the Administration but less accurate than the *Blue Chip* consensus in those two years.

Growth of Nominal Output. Differences between forecast errors for real and nominal output growth indicate inaccuracies in forecasts of inflation in the output price index.[40] For the entire 1979–2011 period covered in this evaluation, all three sets of forecasts overestimated the five-year growth rate of nominal output by more than three-quarters of a percentage point, on average. Overall, errors in forecasts of nominal output tend to be more pronounced around turning points in the economy than errors in forecasts of real output because they depend on forecasts of two cyclical components—real output growth and growth in the output price index.

In the 1980s and 1990s, forecasters' tendency to overestimate inflation contributed to overestimates of nominal output growth (see Figure 17). By contrast, between 2000 and 2005 forecasters tended to underestimate inflation rates, which partially offset their overestimates of real output growth. All the forecasters had large errors in the lead-up to the 2007–2009 recession, and they continued to overestimate economic growth during the recovery.

40. As noted above in the discussion of the two-year forecasts, the forecasters projected GNP before 1992 and have projected GDP since then.

Inflation

In the five-year forecasts they made between 1983 and 2011, CBO, the Administration, and the *Blue Chip* consensus slightly overestimated inflation in the CPI and underestimated the difference between inflation in the CPI and the output price index, on average. (The average error in forecasts of inflation in both indexes is positive, but it is larger for forecasts of inflation in the output price index). The RMSE of the inflation forecasts is roughly similar for all forecasters, indicating that they were all about equally accurate.

Inflation in the CPI. By far, the largest errors in five-year forecasts of inflation in the CPI were made during the late 1970s and early 1980s; projections became more accurate as inflation stabilized starting in the mid-1980s (see Figure 18). Between 1976 and 1979, CBO and the Administration underestimated the inflation rate in their five-year forecasts by an average of 3.2 percentage points and 3.9 percentage points, respectively. As the inflation rate fell during and after the 1981–1982 recession, forecasters gradually lowered their five-year estimates. On average, between 1980 and 1984, CBO overestimated the inflation rate by 2.1 percentage points, and the Administration overestimated it by 1.6 percentage points.

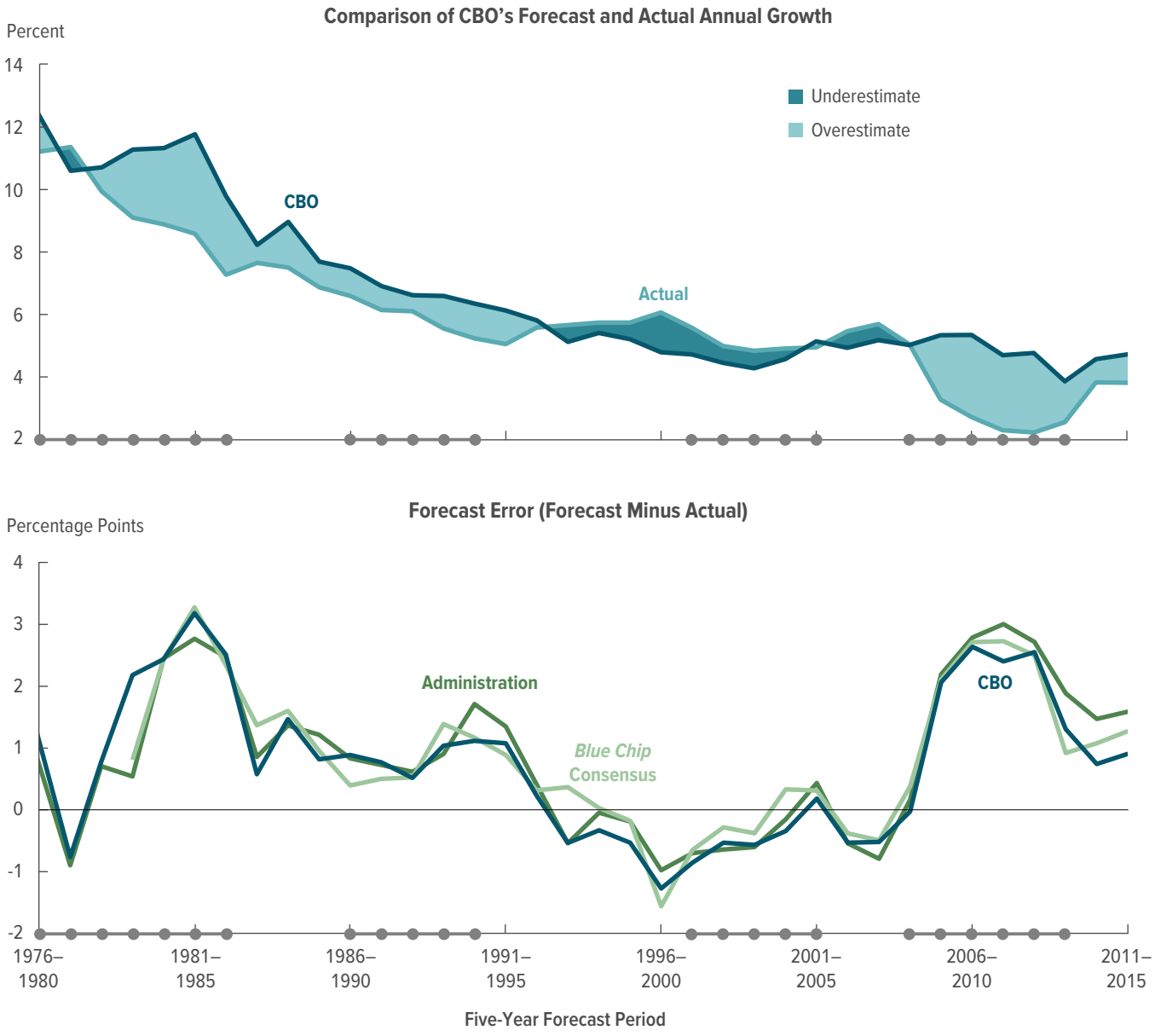
As inflation rates moderated after the early 1980s, errors in the five-year forecasts diminished. Between 1985 and 1999, CBO and the *Blue Chip* consensus overestimated the inflation rate by about one-half of a percentage point, on average, whereas the Administration overestimated the rate by a negligible amount. Nevertheless, all three sets of forecasts had the same mean absolute error over the 1985–1999 period.

All the forecasters made only small errors in projecting the five-year average rate of inflation in 2000 and 2001, but they failed to anticipate the rise in that rate after 2001. As a result, they all underestimated inflation significantly in the forecasts they made from 2002 to 2004.

Errors in forecasts of inflation were generally small from 2005 to 2009. All the forecasters correctly anticipated a fall in inflationary pressures as a result of the 2007–2009 recession and the subsequent slowdown in the growth of output. In 2010, CBO underestimated inflation by one-half of a percentage point, but the next year it accurately forecast inflation. The *Blue Chip* consensus overestimated inflation in both those years, whereas the

Figure 17.

Growth of Nominal Output: Five-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Bureau of Economic Analysis.

The date ranges on the horizontal axis refer to the five-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the five-year forecast period overlapped a recession by six months or more.

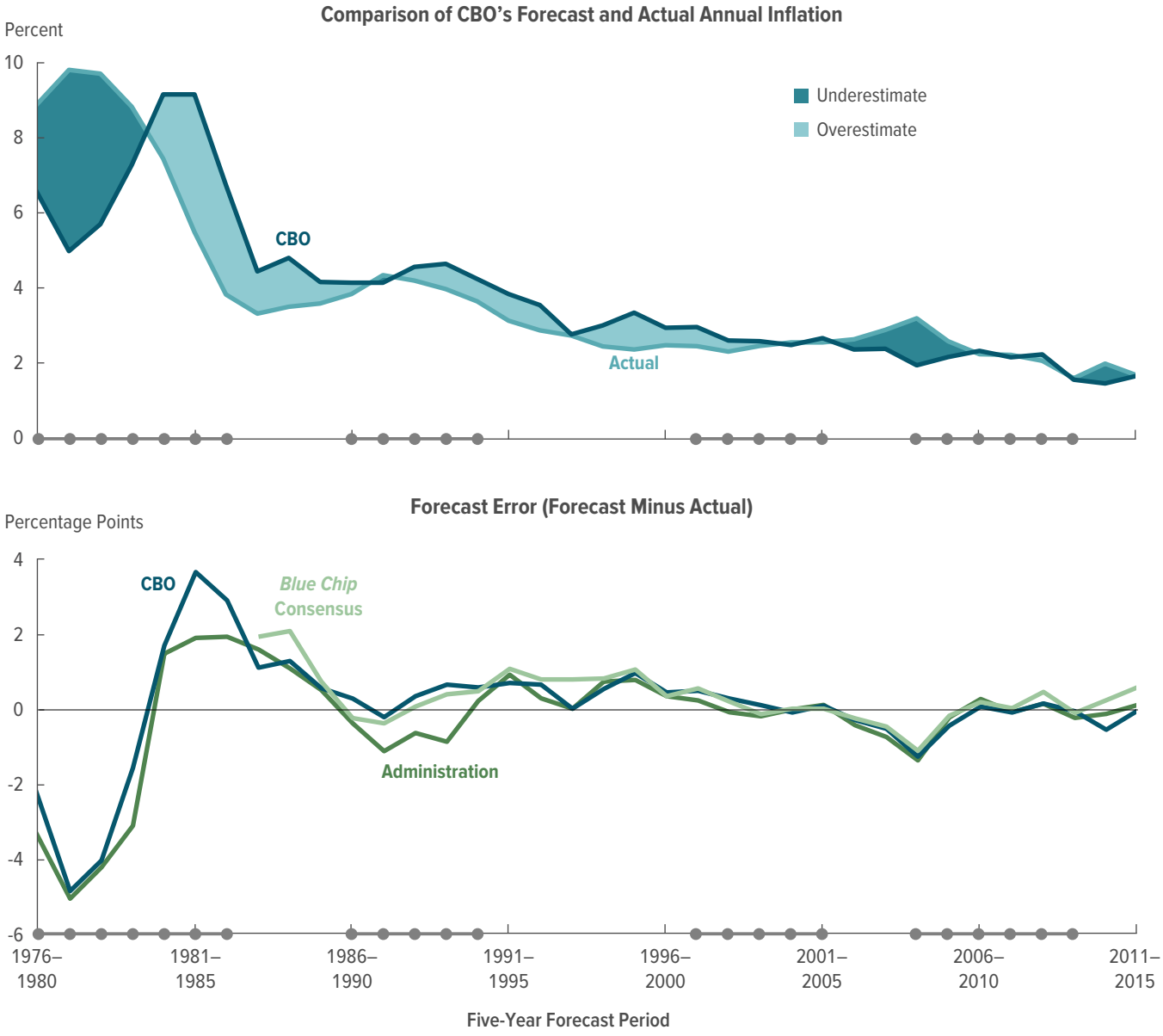
Forecast and actual data show the average annual growth rate of nominal output over the five-year forecast period. Output is either GDP or (before 1992) GNP.

The most recent forecasts included are those published in 2011. The first five-year *Blue Chip* consensus forecast of nominal output was published in 1979.

GDP = gross domestic product; GNP = gross national product.

Figure 18.

Inflation in the Consumer Price Index: Five-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Bureau of Labor Statistics.

The date ranges on the horizontal axis refer to the five-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the five-year forecast period overlapped a recession by six months or more.

Forecast and actual data show the average annual growth rate of the CPI over the five-year forecast period. Most of the forecasts represented here were for the CPI-U, but some were for the CPI-W. For details on the underlying data, see the appendix.

The most recent forecasts included are those published in 2011. The first five-year *Blue Chip* consensus forecast of the CPI was published in 1983.

CPI = consumer price index; CPI-U = consumer price index for all urban consumers; CPI-W = consumer price index for urban wage earners and clerical workers.

Administration made fairly accurate forecasts. Compared with their two-year forecasts from the same period, all of the forecasters' five-year projections of inflation made from 2005 to 2011 were more accurate.

Difference Between Inflation Measures. In the forecasts they prepared between 1976 and 1980, CBO and the Administration underestimated the difference between the five-year average inflation rates measured by the CPI and the output price index by 1.4 percentage points, on average (see Figure 19). The widening of the gap between the two inflation rates was mostly due to the increase in the price of oil in 1979. Between 1983 and 1998, CBO, the Administration, and the *Blue Chip* consensus consistently underestimated the difference between the inflation rates—CBO, by an average of 0.4 percentage points; the Administration, by an average of 0.6 percentage points; and the *Blue Chip* consensus, by an average of 0.5 percentage points. In each of those cases, about 0.2 percentage points of the bias resulted from downward revisions to inflation in the GDP price index that were made following the comprehensive revision to the NIPAs in 1999.

When preparing their projections between 2000 and 2003, none of the forecasters anticipated that the difference between the two inflation measures would decline significantly. They all moderately overestimated the difference in those years.

After 2003, forecast errors were generally small. On the whole, CBO made slightly more accurate forecasts during the 2007–2009 recession than the Administration or the *Blue Chip* consensus did. In 2010 and 2011, all the forecasters slightly overestimated the difference between inflation measures.

Interest Rates

Between 1984 and 2011, CBO, the Administration, and the *Blue Chip* consensus tended to overestimate interest rates on 3-month Treasury bills and 10-year Treasury notes. Five-year forecasts of interest rates exhibited roughly twice as much upward bias as the comparable two-year forecasts and were less accurate than those forecasts as well. That is primarily because interest rates, particularly long-term rates, have declined more persistently since the early 1980s than they were expected to and they have not returned to the levels reached in the 1970s and 1980s.

Like those in the agency's two-year forecasts, the errors in CBO's five-year forecasts of short-term interest rates were largest around recessions. Errors tend to occur then partly because the demand for borrowing typically falls during recessions, which causes short-term interest rates to decline, and partly because the Federal Reserve generally responds to recessions by acting to reduce short-term interest rates.

CBO's tendency to overestimate long-term interest rates over five-year periods is less related to recessions than it is to the largely unanticipated decline in long-term interest rates that began in the early 1980s. CBO overestimated long-term interest rates in most years between 1984 and 2011 because it made those forecasts using models that were based on the assumption that interest rates would move back toward their historical levels. Unexpected trends, such as growing foreign demand for Treasury securities and the declining term premium, as well as factors that affect the long-term growth rates of output, such as the size of the labor force and productivity, add to the uncertainty of the five-year forecasts of interest rates.

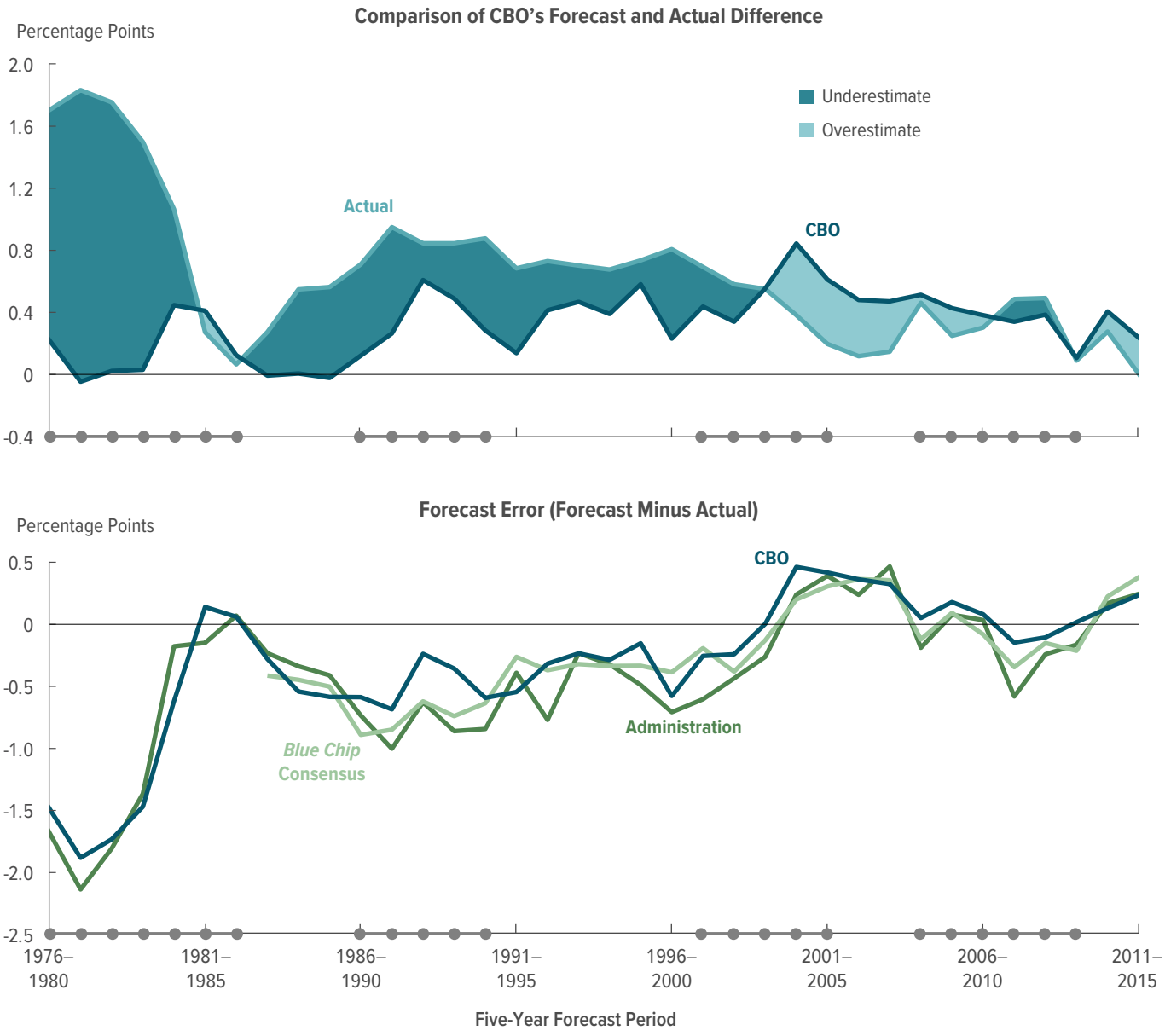
Interest Rate on 3-Month Treasury Bills. On average, between 1983 and 2011, CBO and the *Blue Chip* consensus overestimated nominal interest rates by about 1¼ percentage points, whereas the Administration overestimated them by three-quarters of a percentage point. The Administration's smaller mean error was mostly a consequence of the offsetting effect of larger underestimates rather than of more accurate forecasts overall.

Forecasts of nominal interest rates prepared between 1983 and 2011 were not very accurate (see Figure 20). Forecasts of real interest rates were slightly less biased than the forecasts of nominal interest rates, but they had a similar degree of accuracy (see Figure 21). The difference between errors in projections of nominal and real interest rates stems from errors in projecting inflation. That difference was substantial during the late 1970s and early 1980s but became less pronounced as inflation stabilized.

From 1976 to 1980, CBO and the Administration underestimated nominal interest rates mainly because of surprisingly high inflation during those years. Overestimates of the real interest rate in the forecasts from the first two of those years improved the accuracy of the nominal rate projections, whereas underestimates of the

Figure 19.

Difference Between Inflation in the CPI and in the Output Price Index: Five-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Bureau of Labor Statistics; Bureau of Economic Analysis.

The date ranges on the horizontal axis refer to the five-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the five-year forecast period overlapped a recession by six months or more.

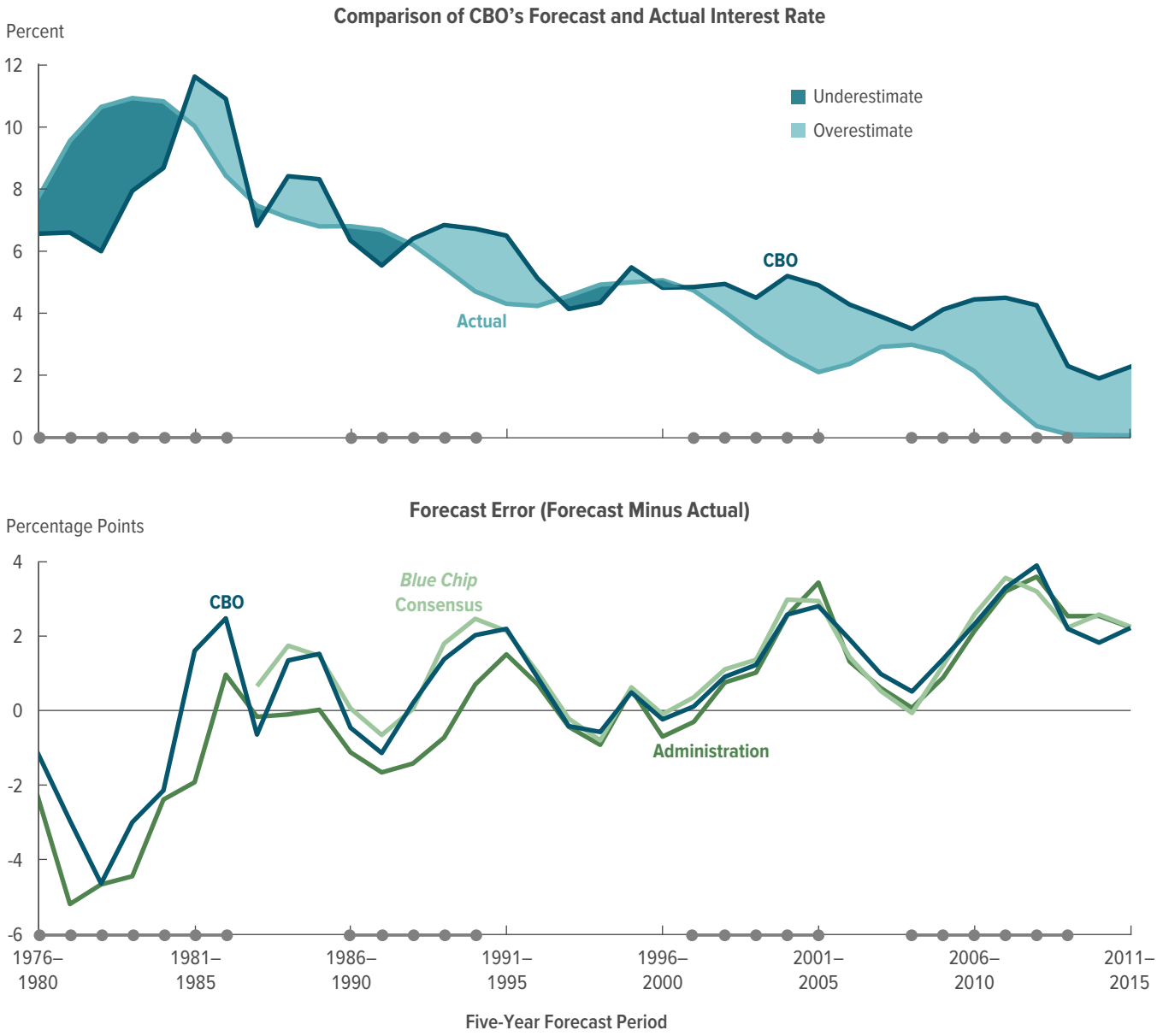
Forecast and actual data show average annual growth in the CPI over the five-year forecast period minus average annual growth in the output price index over that period. In most of the forecasts represented here, the CPI-U was forecast, but in some, the CPI-W was forecast. The output price index measures the prices of all goods and services that make up either GDP or (before 1992) GNP. For details on the underlying data, see the appendix.

The most recent forecasts included are those published in 2011. The first five-year *Blue Chip* consensus forecast of the CPI was published in 1983.

CPI = consumer price index; CPI-U = consumer price index for all urban consumers; CPI-W = consumer price index for urban wage earners and clerical workers; GDP = gross domestic product; GNP = gross national product.

Figure 20.

Interest Rate on 3-Month Treasury Bills: Five-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Federal Reserve; Bureau of the Public Debt.

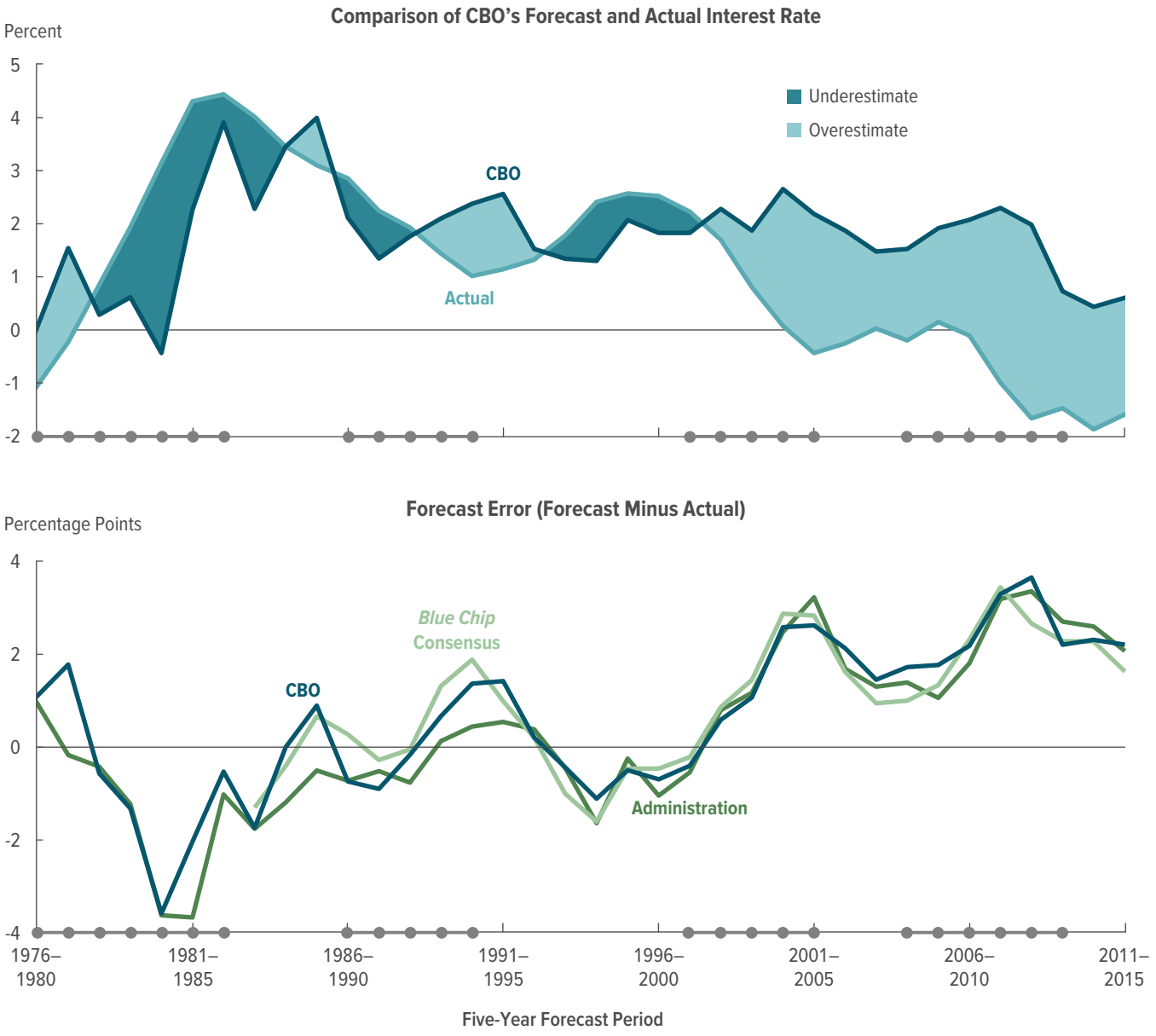
The date ranges on the horizontal axis refer to the five-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the five-year forecast period overlapped a recession by six months or more.

Forecast and actual data show the average annual interest rate over the five-year forecast period. Most of the forecasts represented here were for the secondary-market interest rate, but some were for the rate on newly issued bills or for the 6-month commercial paper rate. For details on the underlying data, see the appendix.

The most recent forecasts included are those published in 2011. The first five-year *Blue Chip* consensus forecast for short-term rates was published in 1983.

Figure 21.

Real Interest Rate on 3-Month Treasury Bills: Five-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Bureau of Labor Statistics; Federal Reserve; Bureau of the Public Debt.

The date ranges on the horizontal axis refer to the five-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the five-year forecast period overlapped a recession by six months or more.

Forecast and actual data show the average nominal annual interest rate over the five-year forecast period deflated by the growth in the CPI over that period. Most of the forecasts represented here were for the secondary-market interest rate, but some were for the rate on newly issued bills or for the 6-month commercial paper rate. In most cases, the CPI-U was used as the deflator, but in some, the CPI-W was used. For details on the underlying data, see the appendix.

The most recent forecasts included are those published in 2011. The first five-year *Blue Chip* consensus forecast for short-term interest rates was published in 1983.

CPI = consumer price index; CPI-U = consumer price index for all urban consumers; CPI-W = consumer price index for urban wage earners and clerical workers.

real interest rate in the 1979 and 1980 forecasts contributed to the errors in projections of the nominal rate.

CBO generally overestimated short-term nominal interest rates in its forecasts from 1981 to 1992, particularly in those it made around the 1990 recession. Notably, the Administration forecast significantly lower nominal interest rates over that period, resulting in underestimates of those rates that were larger than the other forecasters' through the 1980s but in overestimates that were smaller than the others' in the early 1990s.

Errors in projections of interest rates were relatively small between 1993 and 1997 for all forecasters, but they started rising again in the late 1990s. During the 2001 and 2007–2009 recessions, errors increased dramatically, partly because the forecasters failed to anticipate the recessions and the subsequent drop in interest rates and partly because rates remained unusually low during the recovery from both recessions. Over the past 15 years, all the forecasters have made fairly accurate projections of inflation, so nominal and real interest rate errors have tracked each other closely. The one notable exception to that pattern was the period from 2003 to 2005, when underestimates of inflation led to more accurate projections of nominal interest rates for all three sets of forecasts.

In the wake of the 2007–2009 recession, unusually accommodative monetary policy reduced short-term interest rates to near zero. Forecasters did not anticipate that shift, which led them to overestimate both nominal and real interest rates. In addition to monetary policy, low foreign interest rates and concerns about foreign growth led to an increase in demand for Treasury securities that CBO and other forecasters did not foresee in the years after the recession. Forecasters also failed to anticipate the persistence of the downward trend in interest rates.

Interest Rate on 10-Year Treasury Notes. Between 1984 and 2011, CBO and the *Blue Chip* consensus overestimated the nominal interest rates on 10-year Treasury notes, on average. The Administration also overestimated the nominal interest rate on 10-year Treasury notes, on average, but only by about one-third as much as CBO and the *Blue Chip* consensus did. That lower mean error partly reflects the fact that the Administration underestimated the long-term interest rates in the early years of the period, and those underestimates offset the large overestimates it made later (see Figure 22). As measured by the RMSE, the accuracy of all three forecasts was similar.

Forecasters have consistently overestimated interest rates since the early 2000s. The mean errors of forecasts prepared since then were roughly three times larger than mean errors of forecasts made between 1984 and 1999. The unusually slow recoveries from the 2001 and 2007–2009 recessions contributed to the recent increase in forecast error—forecasters continued to overestimate interest rates on 10-year Treasury notes long after the recessions had ended.

Several factors in addition to those slow recoveries account for CBO's and other forecasters' persistently overestimating interest rates since the mid-2000s. The rate of growth in productivity—which is an important determinant of interest rates—has been lower than CBO and other forecasters expected. Additionally, low foreign interest rates, heightened concern about global growth, and increased demand (by both foreign and domestic investors) for Treasury securities as a hedge against possible adverse economic outcomes have further contributed to low interest rates, especially since 2009, when the most recent recession ended. The Federal Reserve's policy of quantitative easing—that is, the direct purchase of long-term Treasury securities, mortgage-backed securities, and agency debt—also contributed to the unusually low long-term interest rates since 2009. Additionally, forecasters failed to anticipate the persistence of the long-term downward trend in interest rates.

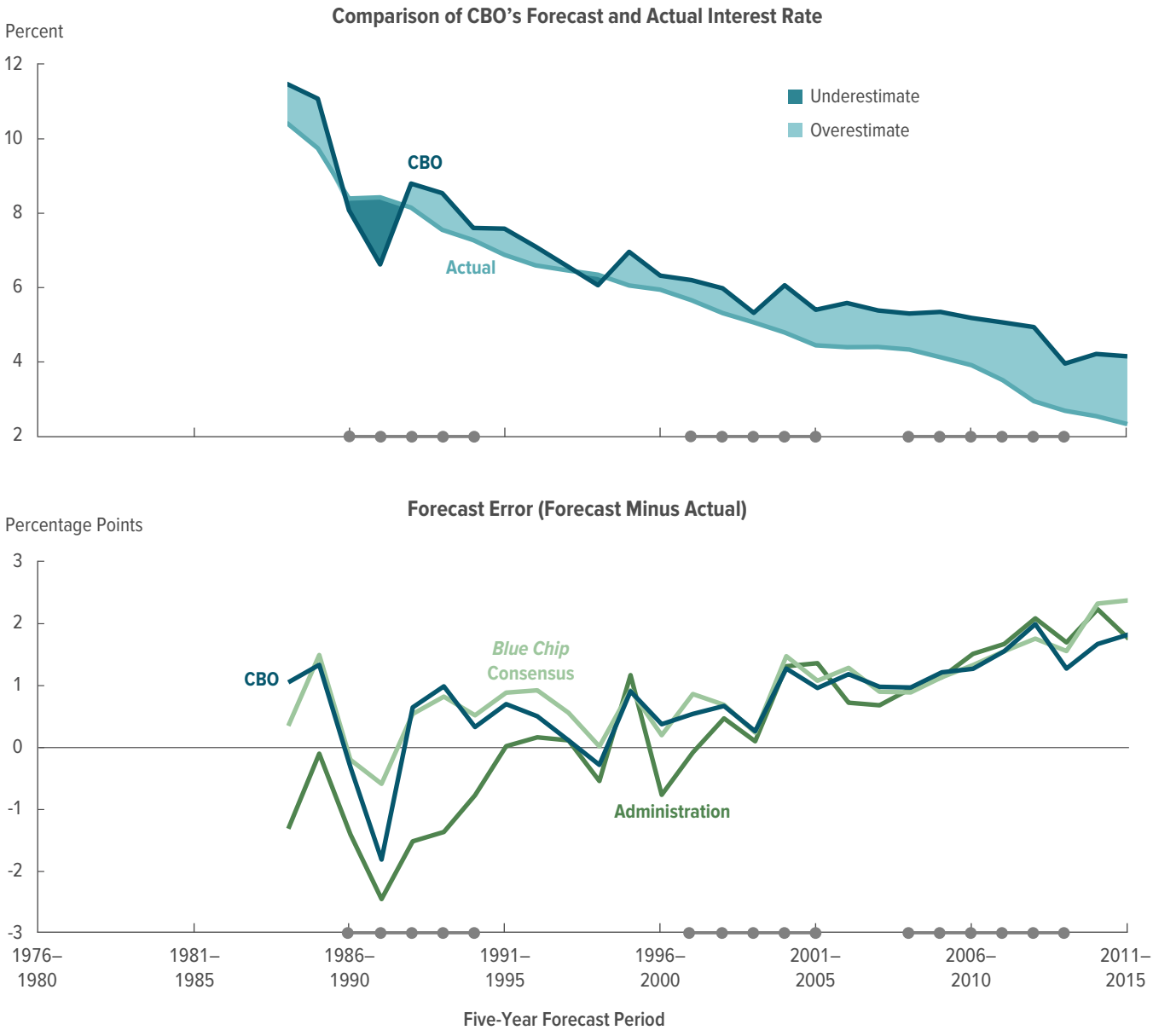
Wages and Salaries

In their forecasts made between 1980 and 2011, CBO and the Administration tended to overestimate the growth of wages and salaries as well as the change in wages and salaries measured as a percentage of output. Forecast errors varied widely over time, however, and included substantial underestimates by both CBO and the Administration between 1995 and 1997.

Growth of Wages and Salaries. Between 1980 and 2011, CBO's and the Administration's forecasts of the five-year average growth rate of wages and salaries exhibited notable upward bias and similar degrees of accuracy (see Figure 23). Compared with the two-year forecasts, they had slightly more upward bias but were nevertheless just as accurate. Like those in the two-year forecasts, the

Figure 22.

Interest Rate on 10-Year Treasury Notes: Five-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Wolters Kluwer, *Blue Chip Economic Indicators*; Federal Reserve.

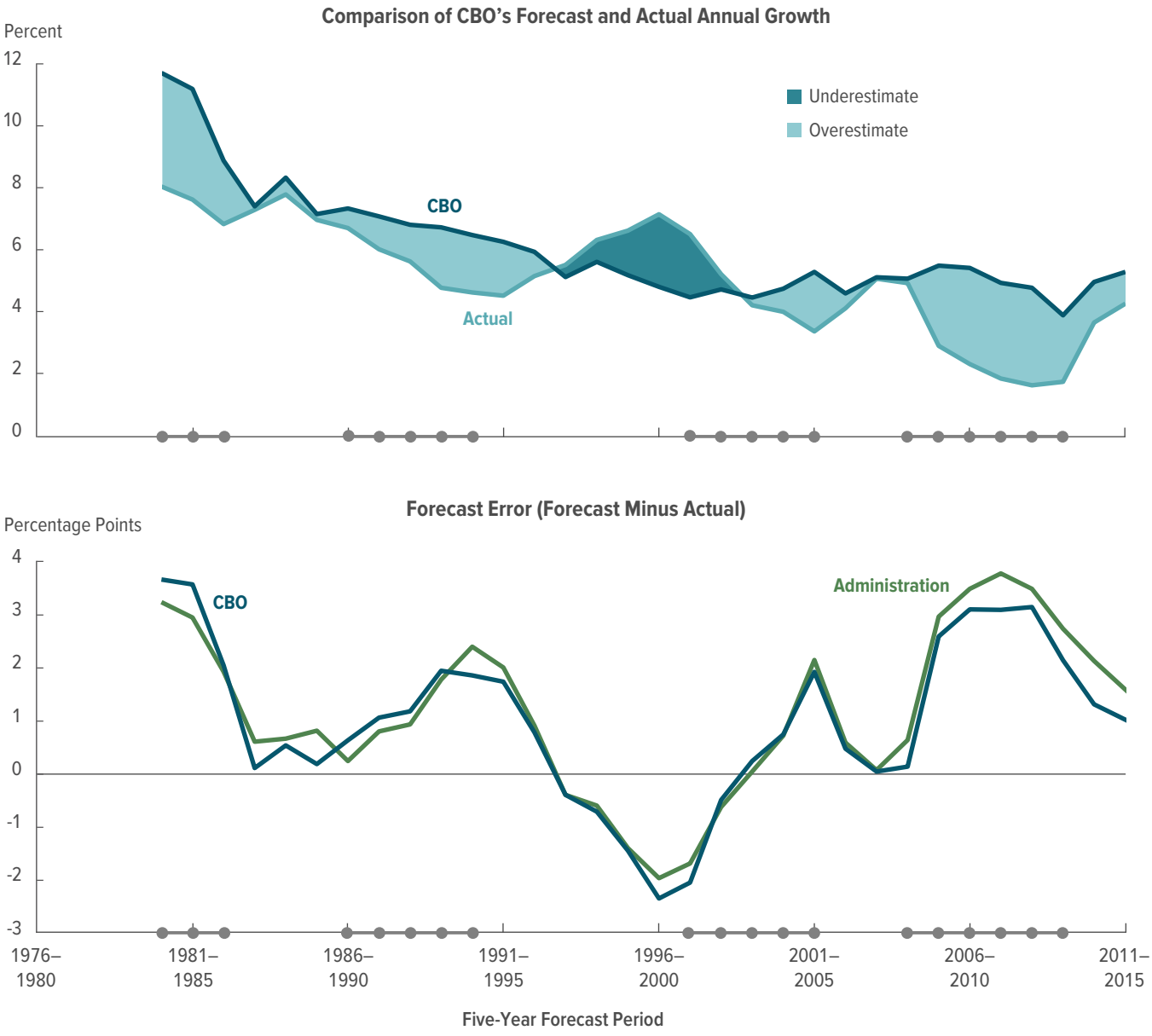
The date ranges on the horizontal axis refer to the five-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the five-year forecast period overlapped a recession by six months or more.

Forecast and actual data show the average annual interest rate over the five-year forecast period. CBO did not forecast the interest rate on 10-year Treasury notes in 1984 or 1985, and the *Blue Chip* consensus did not include forecasts of the rate from 1984 to 1995. In those cases, the forecaster's projections of the Moody's Aaa corporate bond rate were used as a substitute.

Data are for forecasts made between 1984 and 2014.

Figure 23.

Growth of Wages and Salaries: Five-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Bureau of Economic Analysis.

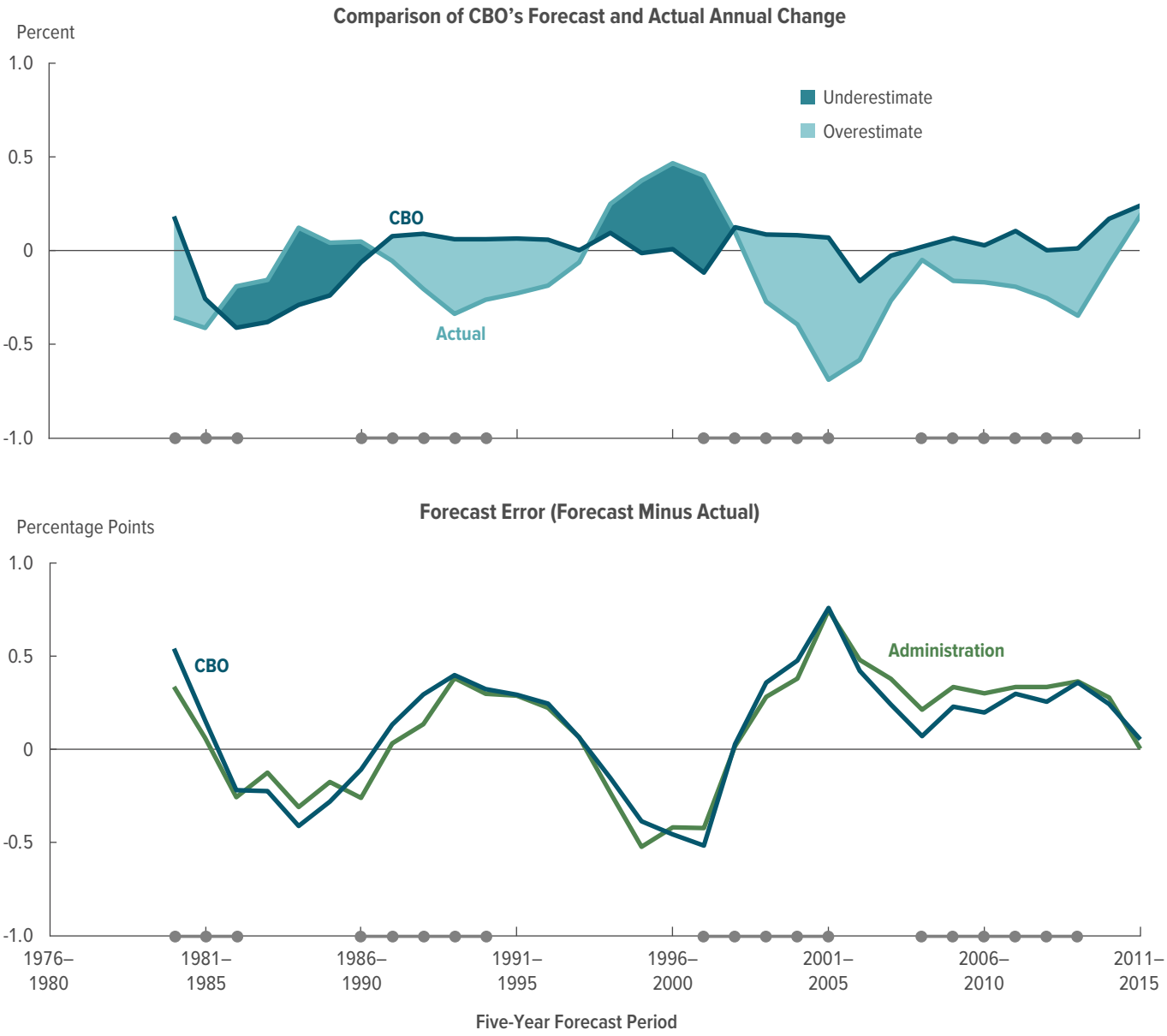
The date ranges on the horizontal axis refer to the five-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the five-year forecast period overlapped a recession by six months or more.

Forecast and actual data show the average annual growth rate of wages and salaries over the five-year forecast period.

Data are for forecasts made between 1980 and 2011. The *Blue Chip* consensus does not include forecasts of wages and salaries.

Figure 24.

Change in Wages and Salaries Measured as a Percentage of Nominal Output: Five-Year Forecasts



Sources: Congressional Budget Office; Office of Management and Budget; Bureau of Economic Analysis.

The date ranges on the horizontal axis refer to the five-year forecast period; each forecast was issued in the first year of that period. The dots indicate that the five-year forecast period overlapped a recession by six months or more.

Forecast and actual data show the average annual change in wages and salaries as a percentage of nominal output over the five-year forecast period. Output is either GDP or (before 1992) GNP.

Data are for forecasts made between 1980 and 2011. The *Blue Chip* consensus does not include forecasts of wages and salaries.

GDP = gross domestic product; GNP = gross national product.

errors in the five-year forecasts of the growth of wages and salaries followed a cyclical pattern.

Change in Wages and Salaries Measured as a Percentage of Output. Between 1980 and 2011, CBO's and the Administration's forecasts of changes in wages and salaries measured as a percentage of output exceeded the actual changes by the same average amount (see Figure 24). Errors in forecasting the change in wages and salaries measured as a percentage of output were related to unexpected trends in the economy.

From 1982 to 1986, CBO and the Administration underestimated the change in wages and salaries measured as a percentage of output in their five-year projections. They may have overestimated the depth and duration of the cyclical decline in labor compensation relative to output following the 1980 and 1981–1982 recessions. Another possibility is that the forecasters overestimated the extent to which labor compensation would shift away from wages to nontaxable benefits.

In the five-year forecasts they made between 1987 and 1993, CBO and the Administration estimated only small changes in wages and salaries measured as a percentage of output, but the actual percentage declined significantly over the years covered by those forecasts. The 1990 recession probably contributed to that unexpected decline.

From 1994 to 1997, CBO and the Administration forecast relatively small changes in wages and salaries measured as a percentage of output over each five-year projection period, but the actual changes exceeded the forecasters' estimates. As with the two-year forecasts, the following three factors probably contributed to the increase during those years:

- Measures of income grew more quickly than GDP;
- Labor compensation temporarily shifted away from nontaxable benefits to wages; and
- Employee stock options became more prevalent, and the value of the stock market rose.

In almost all the forecasts they made between 1999 and 2010, CBO and the Administration projected that in relation to GDP, wages and salaries would either remain roughly flat or rise slightly over the five-year horizon. However, the average five-year change in wages and salaries measured as a percentage of GDP was negative during the 2000s, particularly in the wake of the 2001 and 2007–2009 recessions. As wages and salaries have risen in relation to GDP in recent years, CBO and other forecasters have made more accurate forecasts.

Appendix: Forecast and Historical Data Used in This Evaluation

This appendix provides an overview of the data that the Congressional Budget Office used to evaluate its forecasting record. The evaluation covers forecasts of the growth of real (inflation-adjusted) and nominal output, inflation, interest rates, and changes in wages and salaries. The historical data for output and the output price index used were the current series available from the Bureau of Economic Analysis (BEA). Historical data for inflation and interest rates varied because CBO, the Administration, and the *Blue Chip* consensus used slightly different measures in some years.

Forecasts Included in This Evaluation

CBO evaluated the forecasts that it published between 1976—the first year that the agency made economic projections—and 2014.[1] (Two-year forecasts published in early 2015 were not included because when this analysis was completed, the latest full-year historical data did not extend beyond 2015.) For comparison, the agency also evaluated the Administration's forecasts from those same years. In all but one case, the Administration's forecasts were taken from its annual budget documents; the forecast made in early 1981 by the Reagan Administration, which was based on revisions of the Carter Administration's last budget, came from a separate document.[2]

The *Blue Chip* consensus forecasts included in this evaluation were those published closest to the date on which CBO's forecasts were released. The first two-year forecast by the *Blue Chip* consensus that CBO examined was published in early 1980; however, that forecast did not include all variables. For those indicators that were not included in the 1980 forecast, the earliest possible forecast was used—for inflation measures and interest rates on 3-month Treasury bills, the 1981 forecast, and for long-term interest rates, the 1984 forecast. Although the *Blue Chip* consensus is published monthly, only those forecasts published in March and October extend beyond two years. All but one of the five-year forecasts from the *Blue Chip* consensus used in this evaluation were published in March; the forecast of real output for the 1980–1984 period was published in May 1980. The *Blue Chip* consensus does not include forecasts of all the economic variables that underlie CBO's baseline projections. Most notably, it does not provide forecasts of wages and salaries.

Since 1979, the staff of the Board of Governors of the Federal Reserve System has regularly prepared detailed two-year economic forecasts for the Federal Open Market Committee (FOMC), the body responsible for conducting monetary policy. Those forecasts are released to the public on a delayed schedule, typically five years after they are made. In conjunction with certain meetings of the FOMC, members of the committee—the members of the Board of Governors and the presidents of the regional Federal Reserve Banks—compile their own forecasts for selected economic indicators. The ranges and central tendencies of those forecasts have been published in the minutes of the meetings since late 2007. For forecasts of real output and of inflation in consumer prices made between 1979 and 2011, CBO compared its projections with those prepared by the staff of the board; for those made from 2012 to 2014, the central tendencies of the FOMC members' forecasts were used for comparison. All of the Federal Reserve's forecasts analyzed here were issued in January or February of

1. Because CBO has published forecasts of wages and salaries on a regular basis only since 1985, this analysis used some unpublished forecasts of wages and salaries that the agency made in earlier years.

2. CBO's corresponding forecast was taken from the agency's analysis of President Reagan's budgetary proposals. That forecast presented the agency's baseline projections and did not include the economic effects of the new Administration's fiscal policy proposals. But it did reflect the assumption that the tax and spending policies of the Second Concurrent Resolution on the Budget for Fiscal Year 1981, including accelerated depreciation of investment and a 10 percent cut in personal income taxes, would continue. Another exceptional case occurred in early 1993, when the Clinton Administration adopted CBO's economic assumptions as the basis for its budget. As a result, the errors from the early 1993 forecast are the same for CBO and the Administration.

the initial year of the forecast period or in December of the preceding year.

Output

Historical average growth rates of nominal output are based on calendar-year averages of the most recent quarterly values of gross national product (GNP) and gross domestic product (GDP) published by BEA. In 1991, BEA changed its featured measure of output from GNP to GDP. GNP differs from GDP in that GNP includes the income that U.S. residents earn abroad and excludes the income that foreigners earn in this country.

Growth rates of real output were calculated using calendar-year averages of the most recent quarterly data on real GNP and real GDP published by BEA. Over the years covered in this analysis, BEA made several benchmark revisions to real GNP and GDP. Such revisions make comparing forecasts with actual data difficult.

For example, from 1976 to 1985, forecasters published projections of real GNP growth that reflected BEA's current measure of such growth at the time, which was based on 1972 prices. In late 1985, however, BEA discontinued the series presented in 1972 dollars and began to publish figures for GNP in 1982 dollars. As a result, no official data for GNP growth in 1972 dollars are available for the years after 1984, meaning that the actual two-year average growth rates that would be used to evaluate the forecasts made in 1984 and 1985 are unavailable.

Moreover, from 1986 to 1991, forecasters published projections of the growth of real GNP that were based on 1982 prices. In the second half of 1991, BEA made another benchmark revision and began publishing estimates of GNP in 1987 dollars. Today, the historical annual series for GNP in 1982 dollars is available only through 1990, so no actual two-year average growth rates are available for comparison with the forecasts made in 1990 and 1991. Late in 1995, BEA made another switch—to a chain-weighted measure of GDP. The historical annual series for GDP in 1987 dollars ends with the value for 1994; thus, there are no corresponding actual two-year average growth rates available for the forecasts made in 1994 and 1995.

By periodically updating the series to reflect recent prices, BEA ensures that its benchmark for real output is relevant for analyzing contemporary movements in real growth. But that practice makes it difficult to evaluate forecasts of real output growth that are produced over several years on the basis of a series that is later discontinued. Consequently, comparisons in this evaluation use BEA's chain-type annual-weighted index of real GNP or GDP for all historical values.

Inflation

CBO calculated averages of inflation in the consumer price index from calendar-year averages of monthly data published by the Bureau of Labor Statistics. Before 1978, the bureau published only one consumer price index series, now known as the CPI-W (the price index for urban wage earners and clerical workers). In January 1978, however, the bureau began to publish a second, broader consumer price index series, the CPI-U (the price index for all urban consumers).

Until 1992, the Administration published its forecasts for the CPI-W, the measure used to index most of the federal government's spending for entitlement programs. By contrast, CBO based all but four of its forecasts of inflation published since 1979—those released from 1986 to 1989—on the CPI-U, which is the measure of inflation now used to index federal income tax brackets. The *Blue Chip* consensus and the Federal Reserve have always included forecasts for the CPI-U. Although annual fluctuations in the CPI-U and CPI-W are virtually indistinguishable, the indexes differ in some years.

As part of its analysis, CBO also evaluated forecasts of the difference between CPI inflation and inflation in the price index for output. The agency used the implicit price deflator for GDP (or, before 1992, GNP) available from BEA to measure the price index for output.

Interest Rates

CBO used data published by the Board of Governors of the Federal Reserve System and the Department of the Treasury to calculate two-year averages of short-term and long-term interest rates.

CBO's comparison of forecasts of short-term interest rates relied primarily on historical values for two measures of the interest rate on 3-month Treasury bills: the new-issue rate and the secondary-market rate. Before 2001, the Administration forecast the new-issue rate, which corresponds to the price of 3-month bills auctioned by the Department of the Treasury. The new-issue rate thus reflects the interest that would be earned by

an investor who purchased a bill at auction and held it to maturity. Since mid-2001, the Administration has forecast the secondary-market rate, which corresponds to the price of 3-month bills traded outside of Treasury auctions. Such transactions occur continually in markets that involve many more traders than there are bidders in Treasury auctions. Thus, the secondary-market rate provides a better measure of conditions in financial markets.

Unlike the Administration, CBO has only ever forecast the secondary-market rate. The *Blue Chip* consensus, by contrast, has alternated between the two rates, and, in 1981, it even projected a third—the 6-month commercial paper rate. The *Blue Chip* consensus forecast the new-issue rate from 1982 to 1985, the secondary-market rate from 1986 to 1991, and the new-issue rate again from 1992 to 1997. Since March 1997, the *Blue Chip* consensus has forecast the secondary-market rate. There is no reason to expect the rates to differ persistently; indeed, the differences between their calendar-year averages are minuscule.

CBO likewise compared the various forecasts of long-term interest rates with historical values for two measures of long-term rates: the 10-year Treasury note rate and Moody's Aaa corporate bond rate. A comparison of forecasts made before 1984 is not possible because not all of the forecasters published forecasts of long-term interest rates then. In 1984 and 1985, CBO projected the Aaa corporate bond rate. Since then, however, CBO has projected the 10-year Treasury note rate. The Administration has always published forecasts for the 10-year Treasury note rate. The *Blue Chip* consensus forecast the Aaa corporate bond rate until January 1996, when it switched to the 10-year Treasury rate.

CBO calculated separate historical values for real short-term interest rates using the nominal interest rate and the inflation rate appropriate for each forecaster. In each case, the average interest rate was deflated by the average growth rate of the consumer price index. The resulting real short-term interest rates were similar among forecasts.

Wages and Salaries

The data on wages and salaries used in this report come from the National Income and Product Accounts published by the Department of Commerce's Bureau of Economic Analysis. Wages and salaries are by far the biggest component of national income. CBO evaluates errors in forecasting wages and salaries because, given their share of personal taxable income, they are a key determinant of overall tax receipts.

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About This Document

The Congressional Budget Office regularly evaluates the accuracy of its economic forecasts by comparing them with the economy's actual performance and with others' forecasts. Such evaluations help guide CBO's efforts to improve the quality of its forecasts and, as background information, are also intended to assist Members of Congress in their use of the agency's estimates. In keeping with CBO's mandate to provide objective, impartial analysis, the report makes no recommendations.

Edward Gamber and Claire Sleigh wrote the report with guidance from Kim Kowalewski. Robert Arnold, Mark Booth, Jeffrey Holland (formerly of CBO), and Jeffrey Werling provided helpful comments. Mark Lasky and Adam Staveski fact-checked the report.

Wendy Edelberg, Jeffrey Kling, and John Skeen reviewed the report. Bo Peery edited it, and Jorge Salazar prepared it for publication. The report is available on CBO's website (www.cbo.gov/publication/53090).

Keith Hall
Director
October 2017

Paul E. Debbas, CFA | May 23, 2012 Close Window

What Electric Utilities Are Doing about Regulatory Lag

Electric utilities sometimes find themselves unable to earn an adequate return on equity (ROE). This can occur even after a company receives a rate increase. Even though rates are designed (in theory) to allow a utility to earn a specified ROE, this doesn't necessarily happen in practice. Some utilities can do no better than getting within a percentage point of the allowed ROE. In some cases, the gap is even wider. This is known as regulatory lag.

There are various reasons why regulatory lag occurs. Some states base rates on historical (rather than forward-looking) test years. This makes it hard for the companies to keep up with rising expenses, despite their cost-cutting efforts. (Expenses can be lowered only so much before the reductions hurt system reliability and customer service.) **Avista** (**AVA**) has been hurt by historical test years. In many cases, a utility's capital spending isn't reflected in its rate base until after the utility has received a rate order. In May of 2011, a gas-fired plant of **NV Energy** (**NVE**) began operating, but the utility didn't receive a tariff hike until the start of 2012. If electric or gas volume falls short of the expectations when a rate order was granted, this can make it tough for a utility to earn its allowed ROE. The utility subsidiary of **CH Energy** (**CHG**) has faced this problem. Finally, some companies' kilowatt-hour sales are declining due to economic factors and conservation efforts. As a result, the three utility subsidiaries of **Hawaiian Electric Industries** (**HE**) have earned low ROEs in recent years.

Here are ways to address this problem:

• **More frequent rate filings.** Avista just received a rate increase in Washington state at the start of 2012, but filed another application as soon as it was allowed to do so, in early April. The utility subsidiaries of **Great Plains Energy** (**GXP**) are employing the same strategy in Missouri and Kansas.

• **Immediate recovery of certain capital expenditures.** In Minnesota, capital spending for environmental upgrades and renewable-energy projects is recoverable immediately. This has helped Minnesota Power, a subsidiary of **ALLETE** (**ALE**), in the past few years. Kentucky has a similar regulatory mechanism for costs arising from provisions in the federal Clean Air Act. This is good for **PPL Corporation** (**PPL**), which in 2010 acquired two utilities in the state. Illinois has enacted a law that will benefit the utility subsidiaries of **Exelon** (**EXC**) and **Ameren** (**AEE**) in the state, which will be able to recover costs through a formulaic approach.

• **Tracking mechanisms for certain kinds of expenses.** Most utilities have had fuel adjustment clauses for many years, in order to track fluctuations in fuel and purchased-power costs that aren't reflected in base rates. These mechanisms are going beyond just fuel, however. **ITC Holdings** (**ITC**), the only publicly traded transmission-only utility, has a regulatory plan that enables it to recover the projected increases in most kinds of expenses, with a true-up at the end of each year. (The regulatory mechanism also enables the utility to recover capital spending on an ongoing basis, which was mentioned in the previous section.) Thus, regulatory lag isn't a problem for ITC. For most utilities, however, the tracking mechanisms are much less broad. One example is a property tax tracker that **NorthWestern** (**NWE**) has in Montana, although it covers only 60% of the increased taxes.

• **Mechanisms that decouple revenues and volume.** The electric companies in California have had such a policy in place for many years, in order to encourage conservation that would otherwise hurt a utility's profits. Instead, the growth of utilities there occurs through expansion of their rate bases, rather than rises in kilowatt-hour sales. Hawaii has enacted such a mechanism for Hawaiian Electric's utilities. The new rules also provide for annual rate adjustments for capital spending and rising operating and maintenance expenses. CH Energy's utility subsidiary resolved its aforementioned sales problem through a decoupling mechanism.

The measures discussed above generally reduce the effects of regulatory lag, but do not eliminate them. Even so, they are clearly a boon for electric companies, and their use is likely to increase as utilities request similar mechanisms in additional states.

At the time of this article's writing, the author did not have positions in any of the companies mentioned.

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Industry Economic And Ratings Outlook:

U.S. Regulated Utilities Expected To Continue On Stable Trajectory In 2013

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Industry Economic And Ratings Outlook:

U.S. Regulated Utilities Expected To Continue On Stable Trajectory In 2013

Standard & Poor's Ratings Services' expects the outlook for credit quality in the U.S. investor-owned regulated electric, gas, and water utility sectors to remain stable in 2013. These companies have continued to weather the challenging economy of the past few years with little lasting effect on collective business and financial risk profiles. The essential commodities that the utility sector provides and the rate-regulated nature of the business enable them to generate reasonably stable and predictable cash flows through timely recovery of most costs from customers, despite economic conditions and the challenge of substantial capital investment. In addition, the U.S. utility sector continues to enjoy favorable access to debt and equity capital markets. As a result, we expect utilities' creditworthiness to remain stable.

Economic Outlook

Standard & Poor's economists publish monthly scenarios of where we think the U.S. economy could be heading. Beyond projecting GDP and inflation, we also include outlooks for other major economic categories. We call this forecast our "baseline scenario," and we use it in all areas of our credit analyses. (see table 1). Our current ratings in the regulated utility sectors factor in this scenario. However, we realize that financial market participants also want to know how we think the economy could worsen--or improve--from our baseline scenario. Any point-in-time forecast of the economy will be wrong; it is simply a question of how far wrong. As a result, we also project two additional scenarios, one upside and one downside. We set these scenarios approximately at one standard deviation from the base line (roughly the 20th and 80th percentile of the distribution of possible outcomes). We use the downside case to estimate the credit impact of an economic outlook that is weaker than the expected case.

Standard & Poor's analysis of regulated electric, gas, and water utilities considers the general macroeconomic environment and, in particular, economic indicators that most correlate with customer consumption. Standard & Poor's baseline assumptions that contribute to our current stable view of the regulated utilities include the following indicators (which we recently updated in "U.S. Economic Forecast: New Year’s Resolutions," Jan. 16, 2013):

- Real GDP growth of 3% in both 2013 and 2014;
- An unemployment rate of 7.3% in 2013 and 6.6% in 2014;
- An increase in disposable income of 3.2% in 2013 and 4.6% in 2014;
- Housing starts at around 1.1 million units in 2013 and 1.5 million units in 2014; and
- The 10-year Treasury yield at 2.1% in 2012 and 2.6% in 2013.

In addition, we have assumed generally responsive regulatory decisions and continued solid liquidity and capital market access for this sector.

Effect on ratings

The vast majority of U.S. investor-owned regulated companies have stable credit outlooks and the predominance of ratings remain firmly entrenched in the 'BBB' category, despite the slow economic recovery.

The number of ratings changes has continued to moderate, with upside rating actions still outpacing downgrades in 2012. In 2012, Standard & Poor's raised the corporate credit ratings of 16 utility holding companies and subsidiaries. The main drivers of the upside rating activity were:

- Constructive regulatory mechanisms and supportive rate decisions,
- Mergers with stronger entities,
- Managements' commitment to credit quality and a focus on a straightforward regulated utility business model, and
- Improving financial measures.

There were also 12 downgrades, attributable to:

- Weakening measures of bondholder protection,
- A merger with a lower-rated utility,
- An unexpected and abrupt leadership change at Duke Energy Corp., and
- Increasing business risk and deteriorating economic conditions in Spain regarding Iberdrola S.A. and their effect on its U.S. holdings.

We also lowered the ratings on unregulated energy merchant company, AmerenEnergy Generating Co. (GenCo) several times during 2012. The lower ratings reflect the company's stand-alone credit quality, including its "highly leveraged" financial risk profile and "weak" business risk profile.

The moderation in rating activity stems from an industry economic outlook that, despite modest recovery in the overall U.S. economy, is stable in our base case. On Jan. 1, 2013, Congress reached a compromise to avoid the "fiscal cliff," which removed some, but not all, of the uncertainties that have weighed the recovery down. As a result, our economists have reduced their assessment of the risk of another recession in the next 12 months to 10% to 15% from 15% to 20% (where more weight was on the lower end of the range). Our expectations for the chance of quick turnaround remain around 15% to 20%. Standard & Poor's also expects real GDP to rise 3% for 2013 and 2014. Both figures are stronger than the 2.2% and 2.7% we earlier expected. Higher oil costs are still a major factor for the economy. Our current estimate is that a $10 rise in oil prices will lower real GDP by 0.5% after two years--about 0.25% percentage points per year slower growth. (See "U.S. Economic Forecast: New Year’s Resolutions," Jan. 16, 2013 and "U.S. Economic Forecast: We Can Work It Out", Dec. 21, 2012

Table 1

2013-2014 Industry Economic Outlook for U.S. Regulated Utilities*

	FORECAST/SCENARIOS						ACTUAL
	Downside (10-15%)		Baseline (65-75%)		Upside (15-20%)		
	2013	2014	2013	2014	2013	2014	2012
Macroeconomic indicators							
Real GDP (% change)	(0.54)	1.04	2.18	2.70	3.19	4.03	2.17
Unemployment rate (%)	8.55	9.05	7.66	7.26	7.06	6.07	8.10
Core CPI (% change)	1.61	1.65	1.91	2.06	2.36	2.49	2.12
Household obligations ratio (%)	15.64	15.02	15.56	15.54	15.71	16.41	15.76
Households (mil.)	123.40	124.62	123.68	125.17	123.77	125.46	122.14
CPI (% change)	0.80	1.82	1.42	1.87	2.46	1.66	2.09

Table 1

2013-2014 Industry Economic Outlook for U.S. Regulated Utilities* (cont.)							
ECI, wages, and salaries (% change)	1.14	1.07	1.90	2.06	2.17	2.29	1.83
Yearly % change	1.05	0.99	1.26	1.21	1.33	1.36	1.03
Industry drivers							
Housing starts (mil. units)	0.72	0.88	0.99	1.30	1.16	1.57	0.78
10-yr. Treasury note yield (%)	1.11	1.71	2.02	2.66	3.15	4.22	1.80
Disposable income (% change)	0.22	2.91	3.18	4.63	3.60	5.79	3.06
Consumer spending, electricity (% change)	2.13	4.07	3.56	5.73	3.73	6.47	(1.81)
Power plant nonresidential (% change)	(13.93)	(6.28)	3.46	(10.84)	(12.46)	(2.59)	31.33
Investment in public utilities (% change)	(8.69)	(3.93)	4.95	(6.03)	(6.81)	0.21	20.97
Investment in electric and gas utilities (% change)	(10.43)	(6.51)	5.14	(10.43)	(9.02)	(3.26)	27.14
'BBB' bond yield (%)	4.66	5.22	4.99	5.56	5.71	6.39	4.93
PPI coal (% change)	2.42	1.47	3.20	2.55	3.86	3.53	1.95
PPI electricity (% change)	3.42	3.19	4.02	3.84	4.53	4.08	0.90
Employment, private (mil.)	111.64	112.13	113.51	115.89	114.08	117.54	111.27
Coal % of electricity fuel use	0.39	0.40	0.39	0.40	0.39	0.40	0.37
Natural gas % of electricity fuel use	0.28	0.27	0.28	0.27	0.28	0.27	0.31
Petroleum % of electricity fuel use	0.64	0.62	0.64	0.62	0.64	0.62	0.66
Employment, utilities (mil.)	0.57	0.56	0.57	0.56	0.56	0.55	0.56
Deflator electricity prices (% change)	2.15	3.55	2.66	4.28	3.11	4.60	(0.12)
BBB' interest rate spread (%)	3.55	3.51	2.97	2.89	2.56	2.17	3.13
Real disposable income (% change)	(0.39)	1.45	2.03	3.06	1.65	4.34	1.28

*Based on Standard & Poor's December 2012 forecast. See "U.S. Economic Forecast: We Can Work It Out," published Dec. 21, 2012.

Industry Ratings Outlook

Creditworthiness in the U.S. regulated utility industry has continued a long shift to greater stability. The rating trend for the sector, as measured by outlooks and CreditWatch listings, is still largely biased toward ratings stability. About 86% of all U.S. investor-owned electric, gas, and water utility companies carrying a stable outlook. The balance is almost equally divided between positive and negative outlooks and/or CreditWatch placements. We typically see little degradation or improvement in U.S. regulated electric utilities' business risk and financial risk profiles as economic cycles ebb and flow. As a result, we expect the number of prospective rating changes in the sector to remain moderate in the near-to-intermediate term.

Ratings stability for regulated utilities is reinforced by the essentiality of the critical service that they provide, generally supportive rate regulation, and responsive cost recovery for incremental capital investments. Nevertheless, in times of prolonged exceptional economic hardship, regulators may be very reluctant to approve significantly higher base rates for consumers. As a result, we've seen many state commissions approve alternative ratemaking techniques to traditional base rate case applications, which help utilities sustain cash flow measures, earnings power, and, ultimately, credit quality. Therefore, we believe that our ratings and outlooks, which we assess based on our view of industry- and company-specific factors, are unlikely to change even if economic conditions worsen in the near term. Nonetheless, if

2013 produces accelerating economic growth, there could be some very modest improvement in creditworthiness, although probably not enough to revise ratings generally. A growing economy that brings greater demand is helpful, but profitability is increasingly resistant to general economic conditions as regulatory mechanisms like decoupling (separation of a utility's profits from its sales of the commodity) become more pervasive. However, stronger employment levels would help reduce uncollectible accounts, increases in housing starts and the number of households would increase electricity, gas, and water consumption, and regulatory risk could possibly lessen as concerns about the burden of rate levels on ratepayers abate. Generally, as long as costs are containable (i.e., little or no inflation), a slowing economy should not affect utility profitability very much.

The universe of domestic electric utilities is relatively highly rated, certainly compared with the average 'BB' category for U.S. industrial companies. This is a function of the large percentage of firms with excellent (nearly 90%) or strong business risk profiles, which, however, is generally balanced with aggressive financial risk profiles. As a consequence, almost 62% of the regulated utility industry carries a 'BBB' category corporate credit rating ('BBB+', 'BBB', and 'BBB-'), about 35% 'A-' and above, and just 4% speculative grade ('BB+' and below).

Chart 1

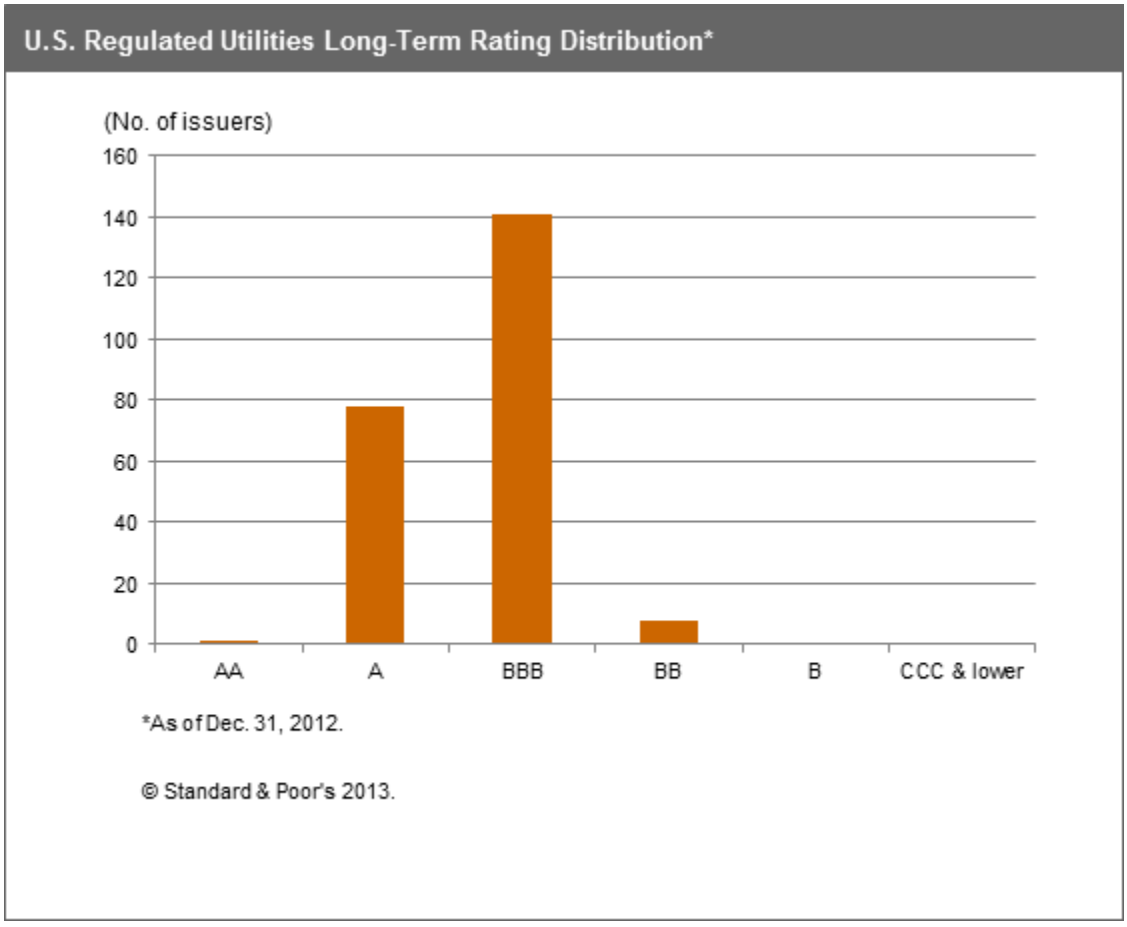
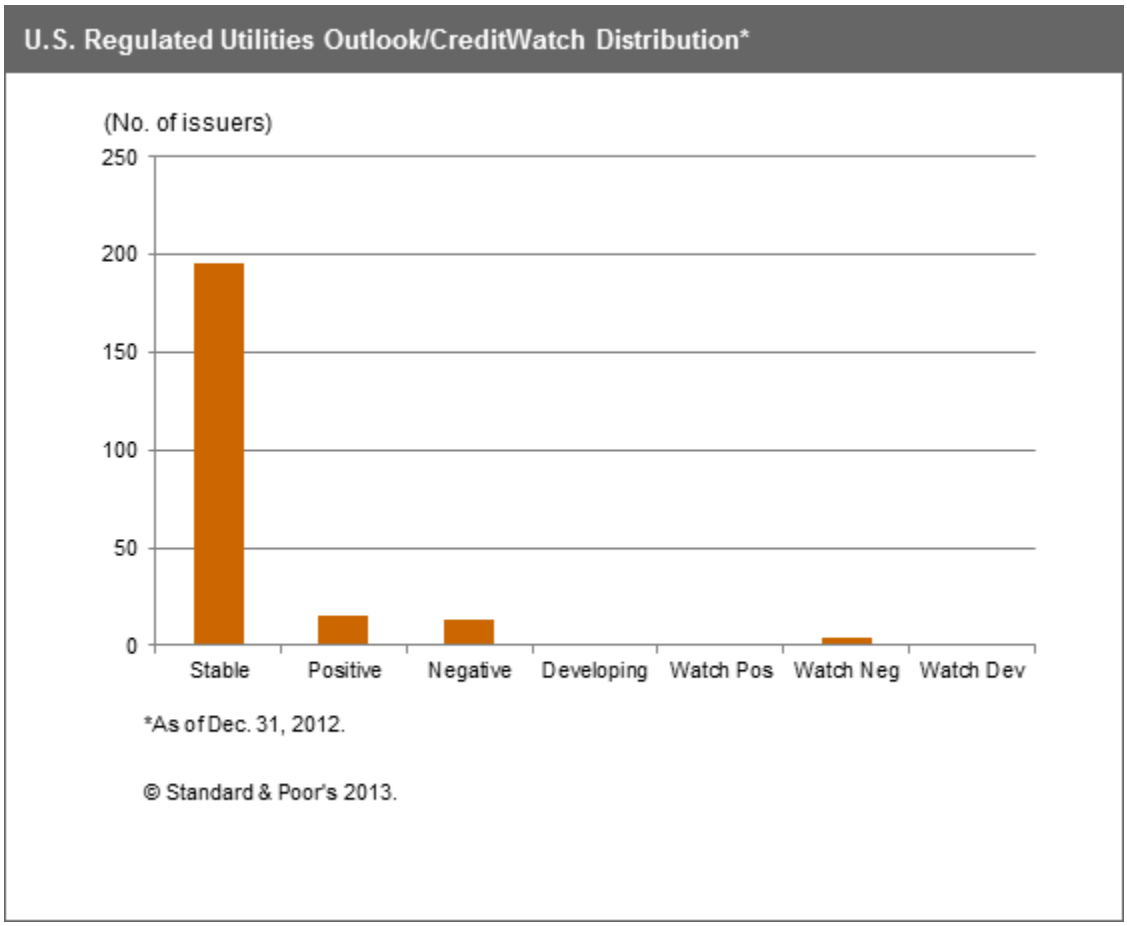


Chart 2



Solid industry fundamentals support stable outlook

The U.S. regulated utility sector performed well through 2012, with ongoing favorable access to debt and equity capital markets compared with most corporate issuers. The amount of medium- to long-term debt and hybrid securities issued during in 2012 was nearly $36 billion.

Regulated utilities have continue to proactively manage their liquidity needs by extending the tenor and/or size of their revolving credit facilities with maturity dates well into 2015 and beyond. Ongoing risks posed by the European sovereign debt crisis, together with a slow economic recovery in the U.S., contributed to the high demand for utility bonds, which drove down bond yields. Liquidity is an industry strength and credit fundamentals indicate that most, if not all, electric utilities should continue to have ample access to funding sources and credit. The certainty provided by the regulatory framework under which utilities operate, regulated utilities' effective monopoly position , the long-lived assets, and associated financing necessary to fund them are all factors that make the utility sector attractive to investors. In addition, many utilities are accessing short-term credit markets through commercial paper programs at very low rates. Issuance of common stock to partially fund construction is also possible for some firms, and would help to support the capital structure balance.

Investor-owned utilities remain on track with multiyear spending plans, which they implemented in recent years to

address aging infrastructure and environmental compliance. As a result, 2011 and 2012 had very high capital spending, with front-loaded projects contributing to peaking levels. We expect construction spending to remain significant, but overall it will be lower compared with 2012. Estimates from S&P Capital IQ show that in 2013 the top 20 utility companies will reduce capital spending by about $5 billion in comparison with 2012. This is less than a 10% reduction from last year, primarily due to accelerated capital outlays to capture favorable depreciation rates before expiration in 2014. The decrease in total capital spending for the utility industry can be traced to decisions by some utilities to reduce or defer spending in 2013 due to current regulatory and economic conditions. Some companies are holding back on discretionary and growth-related construction projects in response to a sluggish economy.

Sustaining traditional creditworthiness in this economy will require strong, collaborative, and effective working relationships among management, regulators and, increasingly, legislators and governors, in planning and executing strategies. Hence, looking to 2013 and beyond, the political and regulatory landscape at the state and federal levels will continue to exert the most influence on electric utility credit ratings. Cost increases, construction projects, environmental compliance, together with lackluster demand, will necessitate continued reliance by utilities on rate relief. Modest economic growth, better consumer and business confidence, and an improving job market should result in more credit-supportive regulatory outcomes. If the economy contracts, if employment levels weaken, and if consumer sentiment declines, regulatory support by state commissions will become more tenuous. Insufficient responses by utilities to counteract a reduction in regulatory support may drag on the industry, especially if utilities come under cost scrutiny by regulators, which is virtually inevitable, and could lead us to a negative stance on overall U.S. electric utilities' credit quality.

Rating Activity In 2012

The upgrades

We raised ratings on Pinnacle West Capital Corp. (PWCC) and subsidiary Arizona Public Service Co. (APS) owing to effective management of regulatory risk and recent rate actions that have been more responsive to the utility's needs. We also expect that the state will continue to emerge from the depths of the recession, leading to increased customer growth. The higher ratings can also be traced to a revision in the company's financial risk profile to "significant" from "aggressive," reflecting continued improvement in cash flow measures and decreased leverage in recent years, as well as prudent financial policies. The stable outlook reflects our view that PWCC will continue to maintain stronger regulatory dealings and that the company will continue to manage the balance sheet with equity issuances that offset expected high capital spending. APS' demonstrated acumen in managing its regulatory agenda provides a platform for higher ratings contingent on financial prudence in containing costs and financing capital investments. Higher ratings are possible with sustained financial performance above our base case forecast level, if adjusted funds from operations (FFO) to debt exceeds 25% consistently and adjusted debt to capital decreases to less than 50%. We could lower the ratings if financial performance deteriorates (with debt leverage reaching more than 60% and adjusted FFO to debt less than 12%), if liquidity weakens, or if the company fails to further its regulatory agenda.

Higher ratings on SEMCO Energy Inc. followed AltaGas Ltd.'s acquisition of SEMCO Holding Co. and take into account the higher credit quality of the new parent. On Aug. 30, 2012, AltaGas purchased SEMCO Holding Co. (SEMCO Energy's parent) for $1.135 billion, including $355 million of assumed debt. AltaGas conservatively financed

the transaction, preserving SEMCO's stand-alone credit quality. Our ratings on SEMCO are limited to the lower of our rating on AltaGas' consolidated credit quality or SEMCO's stand-alone credit quality. The ratings on SEMCO reflect the consolidated credit profile of parent AltaGas. The ratings also reflect SEMCO's "excellent" business risk profile and AltaGas' "significant" financial risk profile. Ratings stability reflects our assessment of AltaGas' business mix, which is diverse with a greater contribution from fee-based and regulated utility cash flows. In our view, near-term financial measures are low for the ratings, although we recognize the cash flows are becoming increasingly sustainable and predictable. We could lower ratings if the company's financial measures do not improve as expected to above 13% FFO to debt in 2014, or if it does not execute and integrate capital projects and acquisitions on time. We expect to see further capital projects and acquisitions financed in line with AltaGas' stated capital structure goals. We could raise the ratings if the business risk profile improves through the addition of less-volatile cash flows that reduce commodity exposure, and financial ratios improve when long-term projects begin to contribute.

We raised the ratings on Rochester Gas & Electric Corp. (RG&E) to reflect improved financial measures, which we expect the company to maintain over the intermediate term, and a business profile that has benefited from constructive regulatory outcomes. A recent multiyear rate settlement includes several supportive recovery mechanisms that enhance the company's ability to earn its authorized return on equity. We base our ratings on RG&E on the utility's stand-alone credit quality because the ultimate parent, Spanish utility holding company Iberdrola S.A., has assumed the debt of RG&E's parent company, Iberdrola USA. We regard the U.S. utility subsidiaries, which include RG&E, Central Maine Power Co., and New York State Electric & Gas Corp., as effectively under Iberdrola S.A.'s direct control, and none individually is a significant source of cash flow for the holding company. Our ratings on RG&E therefore do not reflect significant support from Iberdrola S.A., and they are effectively capped at the rating on the parent. RG&E's excellent business risk profile benefits from a low-operating-risk transmission and distribution business strategy. The company's financial risk profile is aggressive, and while the profile has improved, we believe a sizable capital spending program could cause pressure. The outlook is stable and reflects recent improvement in bondholder protection parameters, decreasing regulatory risk, and our expectations that financial measures will remain in line with current measures. Our baseline forecast shows FFO to total debt of 16%, debt leverage below 55%, and debt to EBITDA of 4x over the near-to-intermediate term. Fundamental to our forecast is the expectation that RG&E employ a low-risk strategy of investing in the regulated transmission and distribution business, maintaining its balanced capital approach, managing regulatory risk, and producing stable cash flow measures. We could lower the ratings if cash flow measures decline to a point where FFO to total debt fell below 15% and total debt to capital remained above 55% on a sustained basis. Based on the parent company's ratings being on CreditWatch with negative implications, we are not currently considering higher ratings.

We raised the ratings on PNM Resources Inc. (PNMR) and subsidiaries Public Service Co. of New Mexico and Texas-New Mexico Power Co. The upgrades reflect PNMR's lower business risk as a result of the company's focus on core electric operations following the previously completed sale of two unregulated businesses, as well as on its management of regulatory matters. We revised the business risk profile to excellent to reflect the lower business risk of the consolidated entity. We believe the company will continue to maintain financial stability through targeting a 50% adjusted debt in the capital structure, bolstering operating cash flows by focusing on timely cost recovery and improving regulatory relationships in New Mexico, where some challenges remain.

We raised the ratings on Integrys Energy Group Inc. and subsidiaries Peoples Energy LLC, Peoples Gas Light & Coke Co., and North Shore Gas Co. to 'A-' from 'BBB+'. The upgrade reflected improvements that Integrys made to its business risk profile and our expectations that the company will be able to maintain financial measures that are consistent with a "significant" financial risk profile over the intermediate term. We revised our assessment of Integrys' business risk profile to "excellent" from "strong" to reflect management's successful implementation of a strategic initiative to reduce exposure to the nonutility businesses and the company's effective management of regulatory risk. In recent years, Integrys has significantly improved its financial measures by increasing cash flow from its regulated units, implementing effective cost containment, and using bonus depreciation. The stable outlook reflects our baseline forecast that consolidated adjusted FFO to debt and debt to capital will approximate 21% and 51%, respectively, over the intermediate term.

The downgrades

We lowered the ratings on DPL Inc. and subsidiary Dayton Power & Light Co. (DP&L) two notches, to 'BB' from 'BBB-', and removed them from CreditWatch negative. The rating action can be traced to our view that increased competition because of lower wholesale electricity prices will continue to materially reduce DPL's profit margins. Also, we expect the unregulated retail business to grow because of the eventual transition to generation market rates. Meanwhile, the company's financial position is stressed due to the substantial amount of acquisition debt layered on by parent company AES Corp. The stable outlook reflects our baseline forecast that consolidated adjusted FFO to debt will be about 8% to 10% over the next 12 to 18 months. Significant risks to the forecast include increasing competition from lower electricity prices that could materially lower DPL's profit margins and a weaker economy than we currently expect. We could lower the ratings if FFO to debt is consistently lower than 8% or the business risk profile weakens as a result of the disproportionate growth of the competitive energy business. Conversely, we could raise the ratings if FFO to debt consistently strengthens to greater than 15% on a sustained basis, which we would expect to result mostly from higher electricity prices and an improved economy.

We lowered the ratings on Duke Energy and its subsidiaries and affirmed the ratings on Progress Energy Inc. and its units and removed the ratings from CreditWatch where they were listed with negative and developing implications, respectively, following the companies' merger. When the merger closed, Progress Energy became a wholly owned subsidiary of Duke. The downgrade on Duke stems from our view that the abrupt and unexpected leadership change at the merged company has heightened regulatory risk in North Carolina and likely in Florida, significantly weakening the company's consolidated "excellent" business risk profile. The North Carolina regulator immediately initiated hearings and an investigation into the management change. We believe that management and the board face a significant challenge in restoring their credibility with regulators and the marketplace.

The negative outlook reflects the potential for lower ratings months if the company fails to address increased levels of regulatory risk in two of its largest jurisdictions, which would move the business risk profile to the "strong" category and at the same time lead to weaker credit protection measures. Our base case projections for Duke incorporate the possibility of delayed but constructive rate-case outcomes in North Carolina and credit-neutral regulatory developments in Florida regarding the Crystal River 3 nuclear plant. These factors are a floor for our expectations, leading to adjusted FFO to total debt of about 18% and adjusted debt leverage of between 50% and 52% by 2014, which would support current ratings. However, if credit measures fall below expectations such that adjusted FFO to

debt is below 16% along with adjusted debt leverage that approaches 55% we will lower the ratings by one notch. In light of pending operational challenges, we do not expect to assign a higher rating to Duke in the intermediate term.

We lowered the ratings on Spain-based utility Iberdrola S.A. and subsidiaries, including Iberdrola USA, and removed the ratings from CreditWatch, where they were placed with negative implications on April 4, 2012. The outlook is stable. Lower ratings reflect the revision of our assessment of Iberdrola's business risk profile to "strong" from "excellent" due to ongoing challenges in the industry environment and deteriorating economic conditions in Spain. We believe that the challenging business and industry environment in Iberdrola's key domestic market could impair the group's profitability because about 47% of revenues come from its Spanish operations. We anticipate that Iberdrola's profit margins in its electricity generating unit could deteriorate in the near term, which is likely to squeeze the group's cash flows. In this segment, the group is exposed to what we see as increasingly difficult and volatile conditions in the liberalized and oversupplied Spanish electricity market. Furthermore, we think that the increase in the budget deficit that we foresee in Spain could increase political risk for sensitive industries such as utilities as the government implements fiscal austerity measures. Also, worsening economic conditions could add to regulatory uncertainty in a jurisdiction in which regulatory determinations are not independent from the government. The stable outlook reflects our opinion that Iberdrola should be able to maintain FFO to debt of about 20%. We believe that the group can sustain this ratio despite the challenging industry and economic environment, as well as any potential delays in the receipt of proceeds from the securitization of the Spanish tariff deficit, and/or any further deficit accumulation. The rating on Iberdrola could remain unchanged even if we were to downgrade Spain by up to two notches. This is because under our criteria, there is a maximum possible rating differential of two notches between the ratings on Iberdrola and those on its related investment-grade sovereign in the eurozone. These criteria apply to Iberdrola because we assess it as having "high" exposure to domestic country risk. That said, if there's another downgrade of Spain, we would evaluate Iberdrola's credit quality separately from that of Spain.

We lowered the ratings on AmerenEnergy Generating Co.(GenCo) twice during the first quarter of 2012 and again in December. The latest downgrade reflected the company's stand-alone credit quality, including its highly leveraged financial risk profile and weak business risk profile. We base our view of GenCo on its stand-alone credit quality, reflecting our assessment of no material support for GenCo by parent Ameren Corp. It is our opinion that Ameren would only provide support to GenCo to the extent that Ameren anticipates an improving forward power price curve by 2018, when its $300 million senior unsecured note matures and incremental environmental capital investments are needed to meet the state's multipollutant standards. The stable outlook incorporates Standard & Poor's base-case scenario for GenCo as a stand-alone company that assumes that profit margins will continue to be pressured by low electricity market prices and the expiration of higher-priced hedges. Under our base-case scenario, the company's financial measures will weaken so that FFO to debt will be less than 10% and debt to EBITDA will be more than 6x. We could lower the ratings if our assessment of the company's strong liquidity weakens to less than adequate or if FFO to debt is consistently less than 5%. We could raise ratings if the U.S. economy improves, increasing demand and electricity prices so that FFO to debt is consistently greater than 12%.

Mixed rating actions

We lowered the ratings on NSTAR and subsidiaries NSTAR Electric Co. and NSTAR Gas Co. to 'A-' from 'A+' and raised the ratings on Northeast Utilities (NU) and subsidiaries Connecticut Light & Power Co., Public Service Co. of

New Hampshire, Western Massachusetts Electric Co., and Yankee Gas Services Co. to 'A-' from 'BBB+'. All ratings came off CreditWatch, where we placed them with negative and positive implications, respectively, on Oct. 18, 2010. The rating actions reflected consummation of the all-stock merger between NU and NSTAR. After the transaction, NSTAR was renamed NSTAR LLC, and NSTAR ceased to exist. As surviving entity, NSTAR LLC assumed all obligations that NSTAR had issued, and became a subsidiary and an intraholding company of NU. The outlook is stable and reflects the company's consistent, regulated electric and natural gas businesses that have low operating risk and which we expect will generate cash flow that is sufficient for the new ratings. Given the large capital spending program and prospects for modest load growth, we expect that NU will generate consolidated adjusted FFO to total debt of about 17% to 18% over the next few years and adjusted total debt to total capitalization of below 54%. We will lower the ratings on NU if adjusted FFO to total debt consistently declines below 15% and debt leverage exceeds 55%. In light of the company's heavy construction program, we don't anticipate a ratings upgrade during our current forecast period. However, if adjusted FFO to total debt consistently exceeds 20%, we could raise the ratings one notch.

Fourth quarter 2012 outlook revisions

We revised the outlook on Laclede Group Inc. (LG) and subsidiary Laclede Gas Co. to negative from stable, reflecting the potential effect on LG's consolidated financial profile in light of the company's announcement to acquire Missouri Gas Energy and New England Gas for $1.035 billion. Although LG plans to use a mix of debt and equity to fund the transaction, the company's current financial position has little cushion at the current rating. A downgrade would be warranted if the consolidated adjusted FFO to total debt ratio were to fall to less than 20% and total debt to total capital rose to more than 50% on a sustained basis. The parties aim to complete the transaction by the end of the third quarter of 2013, with approvals required from the Missouri and Massachusetts regulators and federal entities under the Hart-Scott-Rodino Act. Shareholder approval is not needed.

We revised the outlook on Black Hills Corp. and subsidiary Black Hills Power Inc. to positive from stable to reflect our expectation that there is at least a one-in-three probability that the company will continue to achieve modest improvements in its financial measures that would support a one-notch upgrade. Higher ratings are possible if the company follows through on its intention to reduce debt with the proceeds of shale assets and continues to strengthen its financial condition. Specifically, we could raise the ratings with sustained performance above our base case forecast of adjusted FFO to total debt of 16% and lower than our adjusted debt to total capital of 59%. Fundamental to our forecast are expectations of the redemption of debt and continued improvement in financial measures based on the reduction of capital spending and the reflection of capital investments in revenues. Our baseline forecast includes FFO to total debt of more than 15%, debt to EBITDA of about 4.7x, and debt to total capital of 60%. We could revise the outlook back to stable if financial performance stalls or deteriorates, such that FFO to total debt falls below 14% and debt to capital rises above 63% on a sustained basis.

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Table 2

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Table 2

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Related Criteria And Research

- U.S. Economic Forecast: New Year's Resolutions, Jan. 16, 2013
- U.S. Economic Forecast: We Can Work It Out, Dec. 21, 2012
- Standard & Poor's Revises Its U.S. Utility Regulatory Assessments, Dec. 28, 2012
- Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Use Of CreditWatch And Outlooks, Sept. 14, 2009

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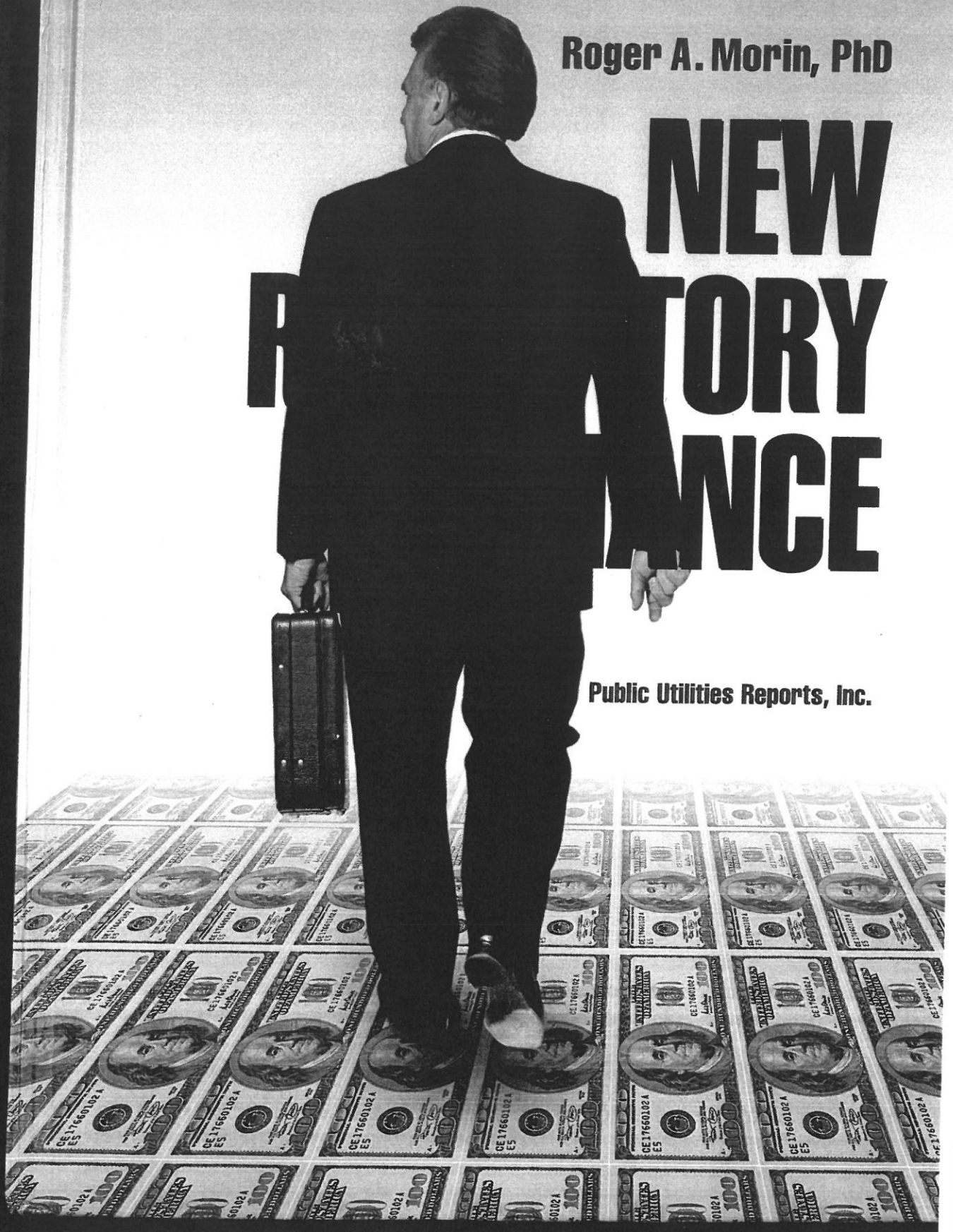
Roger A. Morin, PhD

NEW R TORY ANCE



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Chapter 7
Divisional Cost of Capital and CAPM Applications

The last twenty-five years have witnessed several landmark developments that have made it increasingly difficult to specify a utility's cost of capital using stock prices and market-based estimation models, namely Risk Premium, CAPM, and DCF. The unbundling, or "divisionalizing, functionalizing," of the electric utility industry with the disaggregation of the generation, transmission, distribution, and energy services functions is a prime example. The diversified nature of natural gas pipelines, involving both regulated pipeline activities and unregulated oil and gas production, marketing, and exploration activities, is another example. We have already witnessed the disaggregation of the telecommunications industry with the coexistence of both regulated and unregulated services. As a result of these watershed developments, it has become necessary to recognize the differential risks associated with the different activities of the modern utility.

The objective of this chapter is to explore the theoretical and practical aspects of estimating cost of capital rates for non-traded unbundled entities within public utilities. These entities include operating subsidiaries, functions, divisions, lines of business, regulated versus non-regulated business segments, individual projects, customer classes, and service categories. The term *division* is employed broadly throughout this chapter to signify any such entity.

Stand-Alone Principle

Utility companies are not homogeneous in risk. One can think of a utility company as a portfolio, or bundle, of assets, with each asset within the company carrying a different degree of risk. For example, monopolistic services differ in risk from competitive services; capacity expansion projects are riskier than routine maintenance projects; residential utility services differ in risk from commercial-industrial services; power generation differs in risk from electricity transmission or distribution. Viewing these divisional investments on a stand-alone[1] basis just like any other corporate investment, the higher the risk of

[1] The stand-alone principle asserts that the cost of capital is equivalent to that which would be faced by the utility company raising capital in the capital markets based on its own business and financial profile. Application of this principle suggests that each unbundled segment of a consolidated corporate entity should be treated as if each was operating independently. The stand-alone principle of economics is essential if efficient allocation of capital resources is to be promoted and cross-subsidies avoided.

that investment, the higher the cost of capital. The fact that an operating utility is a wholly owned subsidiary of a parent company is immaterial. The parent company, as the operating company's sole shareholder, should not be discriminated against and treated differently than any other shareholder. The only relevant concerns should be the risk to which a common equity investment in the operating utility subsidiary's rate base is exposed.

A utility operating company, segment, division, or line of business must be treated as a separate stand-alone entity, distinct from its parent company because it is the cost of capital for the division that we are attempting to measure and not the cost of capital for the parent company's consolidated activities. Financial theory clearly establishes that the true cost of capital depends on the use to which the capital is put. Both common sense and financial theory assert that risk-averse investors require higher returns from higher risk investments. This implies that the expected return, or cost of capital, for a higher risk investment exceeds that of a lower risk investment. The specific source of funding an investment and the cost of funds to the investor are irrelevant considerations.

For example, if an individual investor borrows money at the bank at an after-tax cost of 8% and invests the funds in a speculative oil exploration venture, the required return on the investment is not the 8% cost but, rather, the return foregone in speculative projects of similar risk, say 20%. Similarly, the required return on a division (segment, line of business, operating company) is the return forgone in comparable risk activities, and is unrelated to the parent's cost of capital. The cost of capital is governed by the risk to which the capital is exposed and not by the source of funds. The identity of the shareholders has no bearing on the cost of equity, be it either individual investors or a parent holding company.

Company vs Divisional Cost of Capital

Just as individual investors require different returns from different assets in managing their personal financial affairs, so do corporations. A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as for long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between subsidiaries. Thus, the cost of investing funds in an operating utility company is the return forgone on investments of similar risk and is unrelated to the investor's identity.

The company-wide cost of capital is not necessarily appropriate for individual divisions (lines of business, segments) because it superimposes one cost of capital and its implicit risk level on all aspects of the company. This effect is demonstrated graphically by the horizontal line CC in Figure 7-1, which plots an array of divisional investments on a risk-return graph.

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Chapter 9
Risk Premium Report Study – General Information

In Chapter 9, general information about the Risk Premium Report Study is presented. In Chapter 10, detailed examples for estimating cost of equity capital using the Risk Premium Report Study are provided.

Appropriate Use of the Risk Premium Report Study

The risk premia and size premia reported in the Risk Premium Report Study can be used to develop cost of equity capital estimates using both the build-up method and the capital asset pricing model (CAPM). The Risk Premium Report Study is primarily designed to be used to develop cost of equity capital estimates for the large majority of companies that are fundamentally healthy, and for which a "going concern" assumption is appropriate. As such, high-financial-risk (i.e., "distressed") companies are excluded from the base dataset and analyzed separately in the "High-Financial-Risk Study".

Because financial services companies are excluded from the base set of companies used to develop the analyses presented in the Risk Premium Report Study, this study should *not* be used to estimate cost of equity capital for financial services companies. Financial services companies include those companies in finance, insurance, or real estate (i.e., companies with an SIC Code that begins with "6").

The data used in the Risk Premium Report Study is drawn from information on public companies. Therefore, the resulting cost of equity capital estimates using the data are "as if public".

The Risk Premium Report Study can be used to develop estimates of cost of equity capital for divisions, reporting units and closely held businesses without "guessing" at the value of the business before one begins the analysis. Rather, fundamental measures of firm size (e.g., sales, net income, EBITDA) and risk (e.g., operating margin) can be used to directly estimate cost of equity capital for non-public businesses.

MOODY'S
INVESTORS SERVICE

Announcement: Moody's changes the US regulated utility sector outlook to negative from stable

18 Jun 2018

Key financial credit ratios have declined over the past 12 months, and are expected to decline further through 2019 before stabilizing and recovering

New York, June 18, 2018 -- Moody's Investors Service ("Moody's") has changed the fundamental sector outlook for the US regulated electric and gas utility industry to negative from stable. The change in outlook primarily reflects a degradation in key financial credit ratios, specifically the ratio of cash flow from operations to debt, funds from operations (FFO) to debt and retained cash flow to debt, as well as certain book leverage ratios. The change in outlook also reflects uncertainty with respect to the timing and extent of potential changes in regulatory recovery provisions, authorized returns and equity layers or self-help options by individual companies in response to lower cash flow.

"Regulated utilities will be exposed to a higher level of financial risk for the next 12 to 18 months" said Ryan Wobbrock, Vice President -- Senior Analyst. "For utility holding companies, the consolidated ratio of FFO to debt has been on a steady decline, from 19% in 2013 to 17% at year-end 2017, and we expect it to decline further toward 15% through 2019."

The change in fundamental sector outlook reflects a declining financial trend, which is a function of higher holding company debt levels incurred in the last few years and a lower deferred tax contribution to cash flow going forward due to tax reform. In aggregating sector financials, Moody's examined 42 of the largest US utility & power holding companies with at least 10 years of historical financial data.

To mitigate this declining financial trend, several holding companies are taking defensive measures in 2018 to strengthen their balance sheets. On average, however, we expect debt to capitalization ratios to stay around 54% (up from 49% in 2016), large capital spending plans to persist, and dividend growth to increase -- all at the same time that FFO is falling. This trend will also keep debt to EBITDA at a ten year high level of around 5.0x for the next several years.

"With respect to financial mitigation measures, we see more activity in the pursuit of regulatory cost recovery relief than we do with management teams executing material changes to financial policies," said Wobbrock. "Thus far, there has been no discernible adjustments to dividend policies and most utilities continue to incorporate a heavy reliance on debt financing for their sizable negative free cash flow funding needs."

Management teams' defensive efforts and a few initial signs of supportive regulatory responses to tax reform are important first steps in addressing the sector's increased financial risk. However, we believe that it will take longer than 12 -18 months for the sector to exhibit a material financial improvement from these actions.

The fundamental sector outlook could return to stable if Moody's expects that the sector's financial profile will stabilize at today's lower levels, with consolidated FFO to debt metrics remaining steady at 15%. A positive outlook could be considered if we expect a recovery in key cash flow metrics where consolidated cash flow starts to improve by roughly 15%-20% or the ratio of consolidated FFO to debt indicates a return to the 17%-19% range.

The fundamentals sector outlook could stay negative if the key cash flow ratios continue to decline, or if there are signs that a more contentious regulatory environment is emerging. A more contentious regulatory environment is one where litigation is the preferred path of regulatory proceeding (instead of settlements), or where the suite of authorized recovery mechanisms begins to become more limited. Lower authorized returns on equity do not, by themselves, signal a weakening regulatory relationship.

US utilities continue to be viewed as critical infrastructure assets, which means they have a roughly 3x lower probability of default than their non-financial corporate peers. From a liquidity perspective, Moody's incorporates a view that US investor owned regulated electric and gas utilities will maintain unfettered access to the capital markets. In addition, Moody's continues to view regulated utilities as a defensive investment alternative in the event of a wide-spread, short-duration financial market shock. These factors provide the

sector with a strong, investment grade credit profile, which continues to be the case, notwithstanding the negative sector outlook.

The report, "Regulated Utilities -- US: 2019 outlook shifts to negative due to weaker cash flows, continued high leverage," is available to Moody's subscribers at

https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_1128302

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MOODY'S
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RATING METHODOLOGY

Regulated Electric and Gas Utilities

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Summary

This rating methodology explains Moody's approach to assessing credit risk for regulated electric and gas utilities globally and is intended to provide general guidance that helps companies, investors, and other interested market participants understand how qualitative and quantitative risk characteristics are likely to affect rating outcomes for companies in the regulated electric and gas utility industry. This document does not include an exhaustive treatment of all factors that are reflected in Moody's ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.

This rating methodology replaces[1] the Rating Methodology for Regulated Electric and Gas Utilities published in August 2009. While reflecting many of the same core principles as the 2009 methodology, this updated document provides a more transparent presentation of the rating considerations that are usually most important for companies in this sector and incorporates refinements in our analysis that better reflect credit fundamentals of the industry. No rating changes will result from publication of this rating methodology.

This report includes a detailed rating grid and illustrative examples that compare the mapping of rated public companies against the factors in the grid. The grid is a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in the regulated electric and gas utility industry. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary substantially. In addition, the illustrative mapping examples in this document use historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company.

[1] This update may not be effective in some jurisdictions until certain requirements are met.

The grid contains four key factors that are important in our assessment for ratings in the regulated electric and gas utility sector, and a notching factor for structural subordination at holding companies:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength

Some of these factors also encompass a number of sub-factors. Since an issuer's scoring on a particular grid factor or sub-factor often will not match its overall rating, in Appendix C we include a discussion of some of the grid "outliers" – companies whose grid-indicated rating for a specific sub-factor differs significantly from the actual rating – in order to provide additional insights.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks which are not explained in detail in this document, as well as factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that would map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A discussion of the key rating factors that drive ratings

» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), a list of the companies included in our illustrative sample universe of issuers with their ratings, grid-indicated ratings and country of domicile (Appendix B), tables that illustrate the application of the grid to the sample universe of issuers, with explanatory comments on some of the more significant differences between the grid-implied rating for each sub-factor and our actual rating (Appendix C)[2], our approach to ratings within a utility family (Appendix D), a description of the various types of companies rated under this methodology (Appendix E), key industry issues over the intermediate term (Appendix F), regional and other considerations (Appendix G), and treatment of power purchase agreements (Appendix H).

[2] In general, the rating (or other indicator of credit strength) utilized for comparison to the grid-implied rating is the senior unsecured rating for investment-grade issuers, the Corporate Family Rating (CFR) for speculative-grade issuers and the Baseline Credit Assessment (BCA) for Government Related Issuers (GRIs). Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. Related documents that provide additional insight in this area are the rating methodologies "Loss Given Default for Speculative Grade Non-Financial Companies in the US, Canada and EMEA", published June 2009, and "Updated Summary Guidance for Notching Bonds, Preferred Stocks and Hybrid Securities of Corporate Issuers", published February 2007.

What's Changed

While incorporating many of the core principles of the 2009 version, this methodology updates how the four key rating factors are defined, and how certain sub-factors are weighted in the grid.

More specifically, this methodology introduces four equally weighted sub-factors into the two rating factors that are related to regulation –the Regulatory Framework and the Ability to Recover Costs and Earn Returns – in order to provide more granularity and transparency on the overall regulatory environment, which is the most important consideration for this sector.

The weighting of the grid indicators for diversification are unchanged, but the proposed descriptive criteria have been refined to place greater emphasis on the economic and regulatory diversity of each utility's service area rather than the diversity of operations, because we think this emphasis better distinguishes credit risk. We have refined the definitions of the Generation and Fuel Diversity sub-factor to better incorporate the full range of challenges that can affect a particular fuel type.

While the overall weighting of the Financial Strength factor is unchanged, the weighting for two sub-factors that seek to measure debt in relation to cash flow has increased. The 15% weight for CFO Pre-WC/Debt reflects our view that this is the single most predictive financial measure, followed in importance by CFO Pre-WC - Dividends/Debt with a 10% grid weighting. The additional weighting of these ratios is balanced by the elimination of a separate liquidity sub-factor that had a 10% weighting in the prior grid.

Liquidity assessment remains a key focus of our analysis. However, we consider it as a qualitative assessment outside the grid because its credit importance varies greatly over time and by issuer and accordingly is not well represented by a fixed grid weight. See "Other Rating Considerations" for insights on liquidity analysis in this sector.

Lower financial metric thresholds have been introduced for certain utilities viewed as having lower business risk, for instance many US natural gas local distribution companies (LDCs) and certain US electric transmission and distribution companies (T&Ds, which lack generation but generally retain some procurement responsibilities for customers). The low end of the scale in the methodology grid has been extended from B to Caa to better capture our views of more challenging regulatory environments and weaker performance.

We have introduced minor changes to financial metric thresholds at the lower end of the scale, primarily to incorporate this extension of the grid.

We have incorporated scorecard notching for structural subordination at holding companies. Ratings already incorporated structural subordination, but including an adjustment in the scorecard will result in a closer alignment of grid-indicated outcomes and ratings for holding companies.

Treatment of first mortgage bonds (primarily in the US), which was the subject of a Request for Comment in 2009 and adopted subsequent to the 2009 methodology, is summarized in Appendix G.

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities. Documents that describe our approach to such cross-sector methodological considerations can be found here.

About the Rated Universe

The Regulated Electric and Gas Utilities rating methodology applies to rate-regulated[3] electric and gas utilities that are not Networks[4]. Regulated Electric and Gas Utilities are companies whose predominant[5] business is the sale of electricity and/or gas or related services under a rate-regulated framework, in most cases to retail customers. Also included under this methodology are rate-regulated utilities that own generating assets as any material part of their business, utilities whose charges or bills to customers include a meaningful component related to the electric or gas commodity, utilities whose rates are regulated at a sub-sovereign level (e.g. by provinces, states or municipalities), and companies providing an independent system operator function to an electric grid. Companies rated under this methodology are primarily rate-regulated monopolies or, in certain circumstances, companies that may not be outright monopolies but where government regulation effectively sets prices and limits competition.

This rating methodology covers regulated electric and gas utilities worldwide. These companies are engaged in the production, transmission, coordination, distribution and/or sale of electricity and/or natural gas, and they are either investor owned companies, commercially oriented government owned companies or, in the case of independent system operators, not-for-profit or similar entities. As detailed in Appendix E, this methodology covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution utilities with retail customers and/or sub-sovereign regulation, local gas distribution utility companies (LDCs), independent system operators, and regulated generation companies. These companies may be operating companies or holding companies.

An over-arching consideration for regulated utilities is the regulatory environment in which they operate. While regulation is also a key consideration for networks, a utility's regulatory environment is in comparison often more dynamic and more subject to political intervention. The direct relationship that a regulated utility has with the retail customer, including billing for electric or gas supply that has substantial price volatility, can lead to a more politically charged rate-setting environment. Similarly, regulation at the sub-sovereign level is often more accessible for participation by interveners, including disaffected customers and the politicians who want their votes. Our views of regulatory environments evolve over time in accordance with our observations of regulatory, political, and judicial events that affect issuers in the sector.

This methodology pertains to regulated electric and gas utilities and excludes the following types of issuers, which are covered by separate rating methodologies: Regulated Networks, Unregulated Utilities and Power Companies, Public Power Utilities, Municipal Joint Action Agencies, Electric Cooperatives, Regulated Water Companies and Natural Gas Pipelines.

[3] Companies in many industries are regulated. We use the term rate-regulated to distinguish companies whose rates (by which we also mean tariffs or revenues in general) are set by regulators.

[4] Regulated Electric and Gas Networks are companies whose predominant business is purely the transmission and/or distribution of electricity and/or natural gas without involvement in the procurement or sale of electricity and/or gas; whose charges to customers thus do not include a meaningful commodity cost component; which sell mainly (or in many cases exclusively) to non-retail customers; and which are rate-regulated under a national framework.

[5] We generally consider a company to be predominantly a regulated electric and gas utility when a majority of its cash flows, prospectively and on a sustained basis, are derived from regulated electric and gas utility businesses. Since cash flows can be volatile (such that a company might have a majority of utility cash flows simply due to a cyclical downturn in its non-utility businesses), we may also consider the breakdown of assets and/or debt of a company to determine which business is predominant.

Other Related Methodologies

» Regulated Electric and Gas Networks

» Unregulated Utilities and Power Companies

» Natural Gas Pipelines

» US Public Power Electric Utilities with Generation Ownership Exposure

» US Electric Generation & Transmission Cooperatives

» US Municipal Joint Action Agencies

» Government Related Issuers: Methodology Update

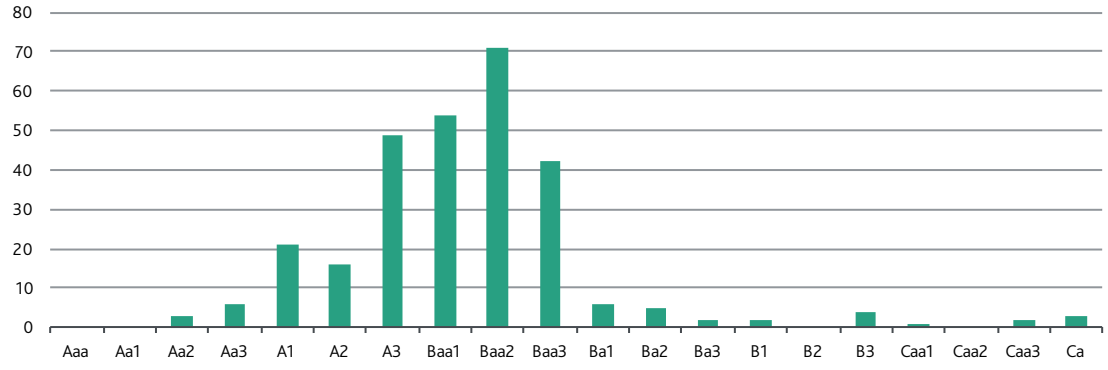
» Global Regulated Water Utilities

The rated universe includes approximately 315 entities that are either utility operating companies or a parent holding company with one or more utility company subsidiaries that operate predominantly in the electric and gas utility business. These companies account for about US$730 billion of total outstanding long-term debt instruments.

The Regulated Electric and Gas Utility sector is predominantly investment grade, reflecting the stability generally conferred by regulation that typically sets prices and also limits competition, such that defaults have been lower than in many other non-financial corporate sectors. However, the nature of regulation can vary significantly from jurisdiction to jurisdiction. Most issuers at the lower end of the ratings spectrum operate in challenging regulatory environments. Additional information about the ratings and default performance of the sector can be found in our publication "Infrastructure Default and Recovery Rates, 1983-2012H1". As shown on the following table, the ratings spectrum for issuers in the sector (both holding companies and operating companies) ranges from Aaa to Ca:

EXHIBIT 1

Regulated Electric and Gas Utilities' Senior Unsecured Ratings Distribution



Source: Moody's Investors Service, ratings as of December 2013

About this Rating Methodology

This report explains the rating methodology for regulated electric and gas utilities in seven sections, which are summarized as follows:

1. Identification and Discussion of the Rating Factors in the Grid

The grid in this rating methodology focuses on four rating factors. The four factors are comprised of sub-factors that provide further detail:

Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%	Legislative and Judicial Underpinnings of the Regulatory Framework	12.5%
		Consistency and Predictability of Regulation	12.5%
Ability to Recover Costs and Earn Returns	25%	Timeliness of Recovery of Operating and Capital Costs	12.5%
		Sufficiency of Rates and Returns	12.5%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Key Financial Metrics	40%		
		CFO pre-WC + Interest/ Interest	7.5%
		CFO pre-WC / Debt	15.0%
		CFO pre-WC – Dividends / Debt	10.0%
		Debt/Capitalization	7.5%
Total	**100%**		**100%**
Notching Adjustment			
		Holding Company Structural Subordination	0 to -3

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor and show the weights used in the grid. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the sub-factors is generally found in or calculated from information in company financial statements, derived from other observations or estimated by Moody's analysts.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in this document to illustrate the application of the rating grid. All of the quantitative credit metrics incorporate Moody's standard adjustments to income statement, cash flow statement and balance sheet amounts for restructuring, impairment, off-balance sheet accounts, receivable securitization programs, under-funded pension obligations, and recurring operating leases.

For definitions of Moody's most common ratio terms please see Moody's Basic Definitions for Credit Statistics, User's Guide (June 2011, document #78480). For a description of Moody's standard adjustments, please see Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations December 2010 (128137). These documents can be found at www.moodys.com under the Research and Ratings directory.

In most cases, the illustrative examples in this document use historic financial data from a recent three year period. However, the factors in the grid can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historic and expected future performance for periods of several years or more, or for individual twelve month periods.

3. Mapping Factors to the Rating Categories

After estimating or calculating each sub-factor, the outcomes for each of the sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B, or Caa).

4. Mapping Issuers to the Grid and Discussion of Grid Outliers

In Appendix C, we provide a table showing how each company in the sample set of issuers maps to grid-indicated ratings for each rating sub-factor and factor. We highlight companies whose grid-indicated performance on a specific sub-factor is two or more broad rating categories higher or lower than its actual rating and discuss the general reasons for such positive and negative outliers for a particular sub-factor.

5. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

6. Determining the Overall Grid-Indicated Rating

To determine the overall grid-indicated rating, we convert each of the sub-factor ratings into a numeric value based upon the scale below.

Aaa	Aa	A	Baa	Ba	B	Caa	Ca
1	3	6	9	12	15	18	20

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	x < 1.5
Aa1	1.5 ≤ x < 2.5
Aa2	2.5 ≤ x < 3.5
Aa3	3.5 ≤ x < 4.5
A1	4.5 ≤ x < 5.5
A2	5.5 ≤ x < 6.5
A3	6.5 ≤ x < 7.5
Baa1	7.5 ≤ x < 8.5
Baa2	8.5 ≤ x < 9.5
Baa3	9.5 ≤ x < 10.5
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 grid-indicated rating. We used a similar procedure to derive the grid indicated ratings shown in the illustrative examples.

7. Appendices

The Appendices provide illustrative examples of grid-indicated ratings based on historical financial information and also provide additional commentary and insights on our view of credit risks in this industry.

Discussion of the Grid Factors

Moody's analysis of electric and gas utilities focuses on four broad factors:

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

There is also a notching factor for holding company structural subordination.

Factor 1: Regulatory Framework (25%)

Why It Matters

For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations. The regulatory environment is comprised of two rating factors - the Regulatory Framework and its corollary factor, the Ability to Recover Costs and Earn Returns. Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation. The Ability to Recover Costs and Earn Returns relates more directly to the actual decisions, including their timeliness and the rate-setting outcomes.

Utility rates[6] are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.

How We Assess Legislative and Judicial Underpinnings of the Regulatory Framework for the Grid

For this sub-factor, we consider the scope, clarity, transparency, supportiveness and granularity of utility legislation, decrees, and rules as they apply to the issuer. We also consider the strength of the regulator's authority over rate-making and other regulatory issues affecting the utility, the effectiveness of the judiciary or other independent body in arbitrating disputes in a disinterested manner, and whether the utility's monopoly has meaningful or growing carve-outs. In addition, we look at how well developed the framework is – both how fully fleshed out the rules and regulations are and how well tested it is – the extent to which regulatory or judicial decisions have created a body of precedent that will help determine future rate-making. Since the focus of our scoring is on each issuer, we consider

[6] In jurisdictions where utility revenues include material government subsidy payments, we consider utility rates to be inclusive of these payments, and we thus evaluate sub-factors 1a, 1b, 2a and 2b in light of both rates and material subsidy payments. For example, we would consider the legal and judicial underpinnings and consistency and predictability of subsidies as well as rates.

how effective the utility is in navigating the regulatory framework – both the utility's ability to shape the framework and adapt to it.

A utility operating in a regulatory framework that is characterized by legislation that is credit supportive of utilities and eliminates doubt by prescribing many of the procedures that the regulators will use in determining fair rates (which legislation may show evidence of being responsive to the needs of the utility in general or specific ways), a long history of transparent rate-setting, and a judiciary that has provided ample precedent by impartially adjudicating disagreements in a manner that addresses ambiguities in the laws and rules will receive higher scores in the Legislative and Judicial Underpinnings sub-factor. A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians seeking to enhance their populist appeal will receive a much lower score.

In general, we view national utility regulation as being less liable to political intervention than regulation by state, provincial or municipal entities, so the very highest scoring in this sub-factor is reserved for this category. However, we acknowledge that states and provinces in some countries may be larger than small nations, such that their regulators may be equally "above-the-fray" in terms of impartial and technically-oriented rate setting, and very high scoring may be appropriate.

The relevant judicial system can be a major factor in the regulatory framework. This is particularly true in litigious societies like the United States, where disagreements between the utility and its state or municipal regulator may eventually be adjudicated in federal district courts or even by the US Supreme Court. In addition, bankruptcy proceedings in the US take place in federal courts, which have at times been able to impose rate settlement agreements on state or municipal regulators. As a result, the range of decisions available to state regulators may be effectively circumscribed by court precedent at the state or federal level, which we generally view as favorable for the credit-supportiveness of the regulatory framework.

Electric and gas utilities are generally presumed to have a strong monopoly that will continue into the foreseeable future, and this expectation has allowed these companies to have greater leverage than companies in other sectors with similar ratings. Thus, the existence of a monopoly in itself is unlikely to be a driver of strong scoring in this sub-factor. On the other hand, a strong challenge to the monopoly could cause lower scoring, because the utility can only recover its costs and investments and service its debt if customers purchase its services. There have some instances of incursions into utilities' monopoly, including municipalization, self-generation, distributed generation with net metering, or unauthorized use (beyond the level for which the utility receives compensation in rates). Incursions that are growing significantly or having a meaningful impact on rates for customers that remain with the utility could have a negative impact on scoring of this sub-factor and on factor 2 - Ability to Recover Costs and Earn Returns.

The scoring of this sub-factor may not be the same for every utility in a particular jurisdiction. We have observed that some utilities appear to have greater sway over the relevant utility legislation and promulgation of rules than other utilities – even those in the same jurisdiction. The content and tone of publicly filed documents and regulatory decisions sometimes indicates that the management team at one utility has better responsiveness to and credibility with its regulators or legislators than the management at another utility.

While the underpinnings to the regulatory framework tend to change relatively slowly, they do evolve, and our factor scoring will seek to reflect that evolution. For instance, a new framework will typically become tested over time as regulatory decisions are issued, or perhaps litigated, thereby setting a body of precedent. Utilities may seek changes to laws in order to permit them to securitize certain costs or collect interim rates, or a jurisdiction in which rates were previously recovered primarily in base rate proceedings may institute riders and trackers. These changes would likely impact scoring of sub-factor 2b - Timeliness of Recovery of Operating and Capital Costs, but they may also be sufficiently significant to indicate a change in the regulatory underpinnings. On the negative side, a judiciary that had formerly been independent may start to issue decisions that indicate it is conforming its decisions to the expectations of an executive branch that wants to mandate lower rates.

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

How We Assess Consistency and Predictability of Regulation for the Grid

For the Consistency and Predictability sub-factor, we consider the track record of regulatory decisions in terms of consistency, predictability and supportiveness. We evaluate the utility's interactions in the regulatory process as well as the overall stance of the regulator toward the utility.

In most jurisdictions, the laws and rules seek to make rate-setting a primarily technical process that examines costs the utility incurs and the returns on investments the utility needs to earn so it can make investments that are required to build and maintain the utility infrastructure - power plants, electric transmission and distribution systems, and/or natural gas distribution systems. When the process remains technical and transparent such that regulators can support the financial health of the utility while balancing their public duty to assure that reliable service is provided at a reasonable cost, and when the utility is able to align itself with the policy initiatives of the governing jurisdiction, the utility will receive higher scores in this sub-factor. When the process includes substantial political intervention, which could take the form of legislators or other government officials publically second-guessing regulators, dismissing regulators who have approved unpopular rate increases, or preventing the implementation of rate increases, or when regulators ignore the laws/rules to deliver an outcome that appears more politically motivated, the utility will receive lower scores in this sub-factor.

As with the prior sub-factor, we may score different utilities in the same jurisdiction differently, based on outcomes that are more or less supportive of credit quality over a period of time. We have observed that some utilities are better able to meet the expectations of their customers and regulators, whether through better service, greater reliability, more stable rates or simply more effective regulatory outreach and communication. These utilities typically receive more consistent and credit supportive outcomes, so they will score higher in this sub-factor. Conversely, if a utility has multiple rapid rate increases, chooses to submit major rate increase requests during a sensitive election cycle or a severe economic downturn, has chronic customer service issues, is viewed as frequently providing incomplete information to regulators, or is tone deaf to the priorities of regulators and politicians, it may receive less consistent and supportive outcomes and thus score lower in this sub-factor.

In scoring this sub-factor, we will primarily evaluate the actions of regulators, politicians and jurists rather than their words. Nonetheless, words matter when they are an indication of future action. We seek to differentiate between political rhetoric that is perhaps oriented toward gaining attention for the viewpoint of the speaker and rhetoric that is indicative of future actions and trends in decision-making.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

This rating factor examines the ability of a utility to recover its costs and earn a return over a period of time, including during differing market and economic conditions. While the Regulatory Framework looks at the transparency and predictability of the rules that govern the decision-making process with respect to utilities, the Ability to Recover Costs and Earn Returns evaluates the regulatory elements that directly impact the ability of the utility to generate cash flow and service its debt over time. The ability to recover prudently incurred costs on a timely basis and to attract debt and equity capital are crucial credit considerations. The inability to recover costs, for instance if fuel or purchased power costs ballooned during a rate freeze period, has been one of the greatest drivers of financial stress in this sector, as well as the cause of some utility defaults. In a sector that is typically free cash flow negative (due to large capital expenditures and dividends) and that routinely needs to refinance very large maturities of long-term debt, investor concerns about a lack of timely cost recovery or the sufficiency of rates can, in an extreme scenario, strain access to capital markets and potentially lead to insolvency of the utility (as was the case when "used and useful" requirements threatened some utilities that experienced years of delay in completing nuclear power plants in the 1980s). While our scoring for the Ability to Recover Costs and Earn Returns may primarily be influenced by our assessment of the regulatory relationship, it can also be highly impacted by the management and business decisions of the utility.

How We Assess Ability to Recover Costs and Earn Returns

The timeliness and sufficiency of rates are scored as separate sub-factors; however, they are interrelated. Timeliness can have an impact on our view of what constitutes sufficient returns, because a strong assurance of timely cost recovery reduces risk. Conversely, utilities may have a strong assurance that they will earn a full return on certain deferred costs until they are able to collect them, or their generally strong returns may allow them to weather some rate lag on recovery of construction-related capital expenditures. The timeliness of cost recovery is particularly important in a period of rapidly rising costs. During the past five years, utilities have benefitted from low interest rates and generally decreasing fuel costs and purchased power costs, but these market conditions could easily reverse. For example, fuel is a large component of total costs for vertically integrated utilities and for natural gas utilities, and fuel prices are highly volatile, so the timeliness of fuel and purchased power cost recovery is especially important.

While Factors 1 and 2 are closely inter-related, scoring of these factors will not necessarily be the same. We have observed jurisdictions where the Regulatory Framework caused considerable credit concerns – perhaps it was untested or going through a transition to de-regulation, but where the track record of rate case outcomes was quite positive, leading to a higher score in the Ability to Recover Costs and Earn Returns. Conversely, there have been instances of strong Legislative and Judicial Underpinnings of the Regulatory Framework where the commission has ignored the framework (which would affect Consistency and Predictability of Regulation as well as Ability to Recover Costs and Earn Returns) or has used extraordinary measures to prevent or defer an increase that might have been justifiable from a cost perspective but would have caused rate shock.

One might surmise that Factors 2 and 4 should be strongly correlated, since a good Ability to Recover Costs and Earn Returns would normally lead to good financial metrics. However, the scoring for the Ability to Recover Costs and Earn Returns sub-factor places more emphasis on our expectation of timeliness and sufficiency of rates over time; whereas financial metrics may be impacted by one-time

events, market conditions or construction cycles - trends that we believe could normalize or even reverse.

How We Assess Timeliness of Recovery of Operating and Capital Costs for the Grid

The criteria we consider include provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress) as well as the process and timeframe of general tariff/base rate cases – those that are fully reviewed by the regulator, generally in a public format that includes testimony of the utility and other stakeholders and interest groups. We also look at the track record of the utility and regulator for timeliness. For instance, having a formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may dampen the benefit to the utility. In addition, we seek to estimate the lag between the time that a utility incurs a major construction expenditures and the time that the utility will start to recover and/or earn a return on that expenditure.

How We Assess Sufficiency of Rates and Returns for the Grid

The criteria we consider include statutory protections that assure full cost recovery and a reasonable return for the utility on its investments, the regulatory mechanisms used to determine what a reasonable return should be, and the track record of the utility in actually recovering costs and earning returns. We examine outcomes of rate cases/tariff reviews and compare them to the request submitted by the utility, to prior rate cases/tariff reviews for the same utility and to recent rate/tariff decisions for a peer group of comparable utilities. In this context, comparable utilities are typically utilities in the same or similar jurisdiction. In cases where the utility is unique or nearly unique in its jurisdiction, comparison will be made to other peers with an adjustment for local differences, including prevailing rates of interest and returns on capital, as well as the timeliness of rate-setting. We look at regulatory disallowances of costs or investments, with a focus on their financial severity and also on the reasons given by the regulator, in order to assess the likelihood that such disallowances will be repeated in the future.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward-looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward-looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.

Factor 3: Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that economic cycles, material changes in a single regulatory regime or commodity price movements will have a severe impact on cash flow and credit quality of a utility. While utilities' sales volumes have lower exposure to economic recessions than many non-financial corporate issuers, some sales components, including industrial sales, are directly affected by economic trends that cause lower production and/or plant closures. In addition, economic activity plays a role in the rate of customer growth in the service territory and (absent energy efficiency and conservation) can often impact usage per customer. The economic strength or weakness of the service territory can affect the political and regulatory environment for rate increase requests by the utility. For utilities in areas prone to severe storms and other natural disasters, the utility's geographic diversity or concentration can be a key determinant for creditworthiness. Diversity among regulatory regimes can mitigate the impact of a single unfavorable decision affecting one part of the utility's footprint.

For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time. For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.

How We Assess Market Position for the Grid

Market position is comprised primarily of the economic diversity of the utility's service territory and the diversity of its regulatory regimes. We also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area. Economic diversity is a typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry. In our assessment, we may consider various information sources. For example, in the US, information sources on the diversity and vitality of economies of individual states and metropolitan areas may include Moody's Economy.com. We also look at the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. While the highest scores in the Market Position sub-factor are reserved for issuers regulated in multiple jurisdictions, when there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility.

Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy will generally score higher in this sub-factor. An issuer with a small service territory economy that has a high dependence on one or two sectors, especially highly cyclical industries, will

generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.

For issuers that are vertically integrated utilities having a meaningful amount of generation, this sub-factor has a weighting of 5%. For electric transmission and distribution utilities without meaningful generation and for natural gas local distribution companies, this sub-factor has a weighting of 10%.

How We Assess Generation and Fuel Diversity for the Grid

Criteria include the fuel type of the issuer's generation and important power purchase agreements, the ability of the issuer to economically shift its generation and power purchases when there are changes in fuel prices, the degree to which the utility and its rate-payers are exposed to or insulated from changes in commodity prices, and exposure to Challenged Source and Threatened Sources (see the explanations for how we generally characterize these generation sources in the table below). A regulated utility's capacity mix may not in itself be an indication of fuel diversity or the ability to shift fuels, since utilities may keep old and inefficient plants (e.g., natural gas boilers) to serve peak load. For this reason, we do not incorporate set percentages reflecting an "ideal" or "sub-par" mix for capacity or even generation. In addition to looking at a utility's generation mix to evaluate fuel diversity, we consider the efficiency of the utility's plants, their placement on the regional dispatch curve, and the demonstrated ability/inability of the utility to shift its generation mix in accordance with changing commodity prices.

Issuers having a balanced mix of hydro, coal, natural gas, nuclear and renewable energy as well as low exposure to challenged and threatened sources of generation will score higher in this sub-factor. Issuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, will score lower.

In evaluating an issuer's degree of exposure to challenged and threatened sources, we will consider not only the existence of those plants in the utility's portfolio, but also the relevant factors that will determine the impact on the utility and on its rate-payers. For instance, an issuer that has a fairly high percentage of its generation from challenged sources could be evaluated very differently if its peer utilities face the same magnitude of those issues than if its peers have no exposure to challenged or threatened sources. In evaluating threatened sources, we consider the utility's progress in its plan to replace those sources, its reserve margin, the availability of purchased power capacity in the region, and the overall impact of the replacement plan on the issuer's rates relative to its peer group. Especially if there are no peers in the same jurisdiction, we also examine the extent to which the utility's generation resources plan is aligned with the relevant government's fuel/energy policy.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	"Challenged Sources" are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	"Threatened Sources" are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

*10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength (40%)

Why It Matters

Electric and gas utilities are regulated, asset-based businesses characterized by large investments in long-lived property, plant and equipment. Financial strength, including the ability to service debt and provide a return to shareholders, is necessary for a utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers.

How We Assess It for the Grid

In comparison to companies in other non-financial corporate sectors, the financial statements of regulated electric and gas utilities have certain unique aspects that impact financial analysis, which is further complicated by disparate treatment of certain elements under US Generally Accepted Accounting Principles (GAAP) versus International Financial Reporting Standards (IFRS). Regulatory accounting may permit utilities to defer certain costs (thereby creating regulatory assets) that a non-utility corporate entity would have to expense. For instance, a regulated utility may be able to defer a substantial portion of costs related to recovery from a storm based on the general regulatory framework for those expenses, even if the utility does not have a specific order to collect the expenses from ratepayers over a set period of time. A regulated utility may be able to accrue and defer a return on equity (in addition to capitalizing interest) for construction-work-in-progress for an approved project based on the assumption that it will be able to collect that deferred equity return once the asset comes into service. For this reason, we focus more on a utility's cash flow than on its reported net income. Conversely, utilities may collect certain costs in rates well ahead of the time they must be paid (for instance, pension costs), thereby creating regulatory liabilities. Many of our metrics focus on Cash Flow from Operations Before Changes in Working Capital (CFO Pre-WC) because, unlike Funds from Operations (FFO), it captures the changes in long-term regulatory assets and liabilities. However, under IFRS the two measures are essentially the same. In general, we view changes in working capital as less important in utility financial analysis because they are often either seasonal (for example, power demand is generally greatest in the summer) or caused by changes in fuel prices that are typically a relatively automatic pass-through to the customer. We will nonetheless examine the impact of working capital changes in analyzing a utility's liquidity (see Other Rating Considerations – Liquidity).

Given the long-term nature of utility assets and the often lumpy nature of their capital expenditures, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from backward-looking measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance. In the illustrative mapping examples in this document, the scoring grid uses three year averages for the financial strength sub-factors. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including such items as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.

For this scoring grid, we have identified four key ratios that we consider the most consistently useful in the analysis of regulated electric and gas utilities. However, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. Our ratings consider the overall financial strength of a company, and in individual cases other financial indicators may also play an important role.

CFO Pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is an indicator for a utility's ability to cover the cost of its borrowed capital. The numerator in the ratio calculation is the sum of CFO Pre-WC and interest expense, and the denominator is interest expense.

CFO Pre-Working Capital / Debt

This important metric is an indicator for the cash generating ability of a utility compared to its total debt. The numerator in the ratio calculation is CFO Pre-WC, and the denominator is total debt.

CFO Pre-Working Capital Minus Dividends / Debt

This ratio is an indicator for financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial, quasi-permanent outflows that can affect the ability of a utility to cover its debt obligations, and this ratio can also provide insight into the financial policies of a utility or utility holding company. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. The numerator of this ratio is CFO Pre-WC minus dividends, and the denominator is total debt.

Debt/Capitalization

This ratio is a traditional measure of balance sheet leverage. The numerator is total debt and the denominator is total capitalization. All of our ratios are calculated in accordance with Moody's standard adjustments[7], but we note that our definition of total capitalization includes deferred taxes in addition to total debt, preferred stock, other hybrid securities, and common equity. Since the presence or absence of deferred taxes is a function of national tax policy, comparing utilities using this ratio may be more meaningful among utilities in the same country or in countries with similar tax policies. High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in bank credit facilities or other financing agreements[8]. A high ratio may result from a regulatory framework that does not permit a robust cushion of equity in the capital structure, or from a material write-off of an asset, which may not have impacted current period cash flows but could affect future period cash flows relative to debt.

There are two sets of thresholds for three of these ratios based on the level of the issuer's business risk – the Standard Grid and the Lower Business Risk (LBR) Grid. In our view, the different types of utility entities covered under this methodology (as described in Appendix E) have different levels of business risk.

Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.

[7] In certain circumstances, analysts may also apply specific adjustments.

[8] We also examine debt/capitalization ratios as defined in applicable covenants (which typically exclude deferred taxes from capitalization) relative to the covenant threshold level.

Other types of utilities may have lower business risk, such that we believe that they are most appropriately assessed using the LBR Grid, due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural disasters. For instance, we tend to view many US natural gas local distribution companies (LDCs) and certain US electric transmission and distribution companies (T&Ds, which lack generation but generally retain some procurement responsibilities for customers), as typically having a lower business risk profile than their vertically integrated peers. In cases of T&Ds that we do not view as having materially lower risk than their vertically integrated peers, we will apply the Standard grid. This could result from a regulatory framework that exposes them to energy supply risk, large capital expenditures for required maintenance or upgrades, a heightened degree of exposure to catastrophic storm damage, or increased regulatory scrutiny due to poor reliability, or other considerations. The Standard Grid will also apply to LDCs that in our view do not have materially lower risk; for instance, due to their ownership of high pressure pipes or older systems requiring extensive gas main replacements, where gas commodity costs are not fully recovered in a reasonably contemporaneous manner, or where the LDC is not well insulated from declining volumes.

The four key ratios, their weighting in the grid, and the Standard and LBR scoring thresholds are detailed in the following table.

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.5%		≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
CFO pre-WC / Debt	15%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.5%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Notching for Structural Subordination of Holding Companies

Why It Matters

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries that are structured as advances, debt, or even hybrid securities.

Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and grid scoring is thus based on

consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and non-utility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors. By contrast, the debt of the HoldCo is typically serviced primarily by dividends that are up-streamed by the OpCos[9]. Under normal circumstances, these dividends are made from net income, after payment of the OpCo's interest and preferred dividends. In most non-financial corporate sectors where cash often moves freely between the entities in a single issuer family, this distinction may have less of an impact. However, in the regulated utility sector, barriers to movement of cash among companies in the corporate family can be much more restrictive, depending on the regulatory framework. These barriers can lead to significantly different probabilities of default for HoldCos and OpCos. Structural subordination also affects loss given default. Under most default[10] scenarios, an OpCo's creditors will be satisfied from the value residing at that OpCo before any of the OpCo's assets can be used to satisfy claims of the HoldCo's creditors. The prevalence of debt issuance at the OpCo level is another reason that structural subordination is usually a more serious concern in the utility sector than for investment grade issuers in other non-financial corporate sectors.

The grids for factors 1-4 are primarily oriented to OpCos (and to some degree for HoldCos with minimal current structural subordination; for example, there is no current structural subordination to debt at the operating company if all of the utility family's debt and preferred stock is issued at the HoldCo level, although there is structural subordination to other liabilities at the OpCo level). The additional risk from structural subordination is addressed via a notching adjustment to bring grid outcomes (on average) closer to the actual ratings of HoldCos.

How We Assess It

Grid-indicated ratings of holding companies may be notched down based on structural subordination. The risk factors and mitigants that impact structural subordination are varied and can be present in different combinations, such that a formulaic approach is not practical and case-by-case analyst judgment of the interaction of all pertinent factors that may increase or decrease its importance to the credit risk of an issuer are essential.

Some of the potentially pertinent factors that could increase the degree and/or impact of structural subordination include the following:

- Regulatory or other barriers to cash movement from OpCos to HoldCo
- Specific ring-fencing provisions
- Strict financial covenants at the OpCo level
- Higher leverage at the OpCo level
- Higher leverage at the HoldCo level[11]
- Significant dividend limitations or potential limitations at an important OpCo
- HoldCo exposure to subsidiaries with high business risk or volatile cash flows

[9] The HoldCo and OpCo may also have intercompany agreements, including tax sharing agreements, that can be another source of cash to the HoldCo.

[10] Actual priority in a default scenario will be determined by many factors, including the corporate and bankruptcy laws of the jurisdiction, the asset value of each OpCo, specific financing terms, inter-relationships among members of the family, etc.

[11] While higher leverage at the HoldCo does not increase structural subordination per se, it exacerbates the impact of any structural subordination that exists

» Strained liquidity at the HoldCo level

» The group's investment program is primarily in businesses that are higher risk or new to the group

Some of the potentially mitigating factors that could decrease the degree and/or impact of structural subordination include the following:

» Substantial diversity in cash flows from a variety of utility OpCos

» Meaningful dividends to HoldCo from unlevered utility OpCos

» Dependable, meaningful dividends to HoldCo from non-utility OpCos

» The group's investment program is primarily in strong utility businesses

» Inter-company guarantees - however, in many jurisdictions the value of an upstream guarantee may be limited by certain factors, including by the value that the OpCo received in exchange for granting the guarantee

Notching for structural subordination within the grid may range from 0 to negative 3 notches. Instances of extreme structural subordination are relatively rare, so the grid convention does not accommodate wider differences, although in the instances where we believe it is present, actual ratings do reflect the full impact of structural subordination.

A related issue is the relationship of ratings within a utility family with multiple operating companies, and sometimes intermediate holding companies. Some of the key issues are the same, such as the relative amounts of debt at the holding company level compared to the operating company level (or at one OpCo relative to another), and the degree to which operating companies have credit insulation due to regulation or other protective factors. Appendix D has additional insights on ratings within a utility family.

Rating Methodology Assumptions and Limitations, and Other Rating Considerations

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that would enable the grid to map more closely to actual ratings. Accordingly, the four rating factors and the notching factor in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used to illustrate the mapping in the grid in this document is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we can't disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that sovereign credit risk is strongly correlated with that of other domestic issuers, that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all companies in any industry such as the quality and experience of management, assessments of corporate governance and the quality of financial reporting and information disclosure. Therefore ranking these factors by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government interference in some countries. Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible to precisely express these in the rating methodology grid without making the grid excessively complex and significantly less transparent. Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position.

Other Rating Considerations

Moody's considers other factors in addition to those discussed in this report, but in most cases understanding the considerations discussed herein should enable a good approximation of our view on the credit quality of companies in the regulated electric and gas utilities sector. Ratings consider our assessment of the quality of management, corporate governance, financial controls, liquidity management, event risk and seasonality. The analysis of these factors remains an integral part of our rating process.

Liquidity and Access to Capital Markets

Liquidity analysis is a key element in the financial analysis of electric and gas utilities, and it encompasses a company's ability to generate cash from internal sources as well as the availability of external sources of financing to supplement these internal sources. Liquidity and access to financing are of particular importance in this sector. Utility assets can often have a very long useful life- 30, 40 or even 60 years is not uncommon, as well as high price tags. Partly as a result of construction cycles, the utility sector has experienced prolonged periods of negative free cash flow – essentially, the sum of its dividends and its capital expenditures for maintenance and growth of its infrastructure frequently exceeds cash from operations, such that a portion of capital expenditures must routinely be debt financed. Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility. Substantial portions of capex are non-discretionary (for example, maintenance, adding customers to the network, or meeting environmental mandates); however, utilities were swift to cut or defer discretionary spending during the 2007-2009 recession. Dividends represent a quasi-permanent outlay, since utilities will typically only rarely cut their dividend. Liquidity is also important to meet

maturing obligations, which often occur in large chunks, and to meet collateral calls under any hedging agreements.

Due to the importance of liquidity, incorporating it as a factor with a fixed weighting in the grid would suggest an importance level that is often far different from the actual weight in the rating. In normal circumstances most companies in the sector have good access to liquidity. The industry generally requires, and for the most part has, large, syndicated, multi-year committed credit facilities. In addition, utilities have demonstrated strong access to capital markets, even under difficult conditions. As a result, liquidity has generally not been an issue for most utilities and a utility with very strong liquidity may not warrant a rating distinction compared to a utility with strong liquidity. However, when there is weakness in liquidity or liquidity management, it can be the dominant consideration for ratings.

Our assessment of liquidity for regulated utilities involves an analysis of total sources and uses of cash over the next 12 months or more, as is done for all corporates. Using our financial projections of the utility and our analysis of its available sources of liquidity (including an assessment of the quality and reliability of alternate liquidity such as committed credit facilities), we evaluate how its projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to its projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, our projection of potential liquidity calls on financial hedges, and important issuer-specific items such as special tax payments). We assume no access to capital markets or additional liquidity sources, no renewal of existing credit facilities, and no cut to dividends. We examine a company's liquidity profile under this scenario, its ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability.

Management Quality and Financial Policy

The quality of management is an important factor supporting the credit strength of a regulated utility or utility holding company. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and in evaluating management performance relative to performance of competitors and our projections. A record of consistency provides Moody's with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

We also assess financial policy (including dividend policy and planned capital expenditures) and how management balances the potentially competing interests of shareholders, fixed income investors and other stakeholders. Dividends and discretionary capital expenditures are the two primary components over which management has the greatest control in the short term. For holding companies, we consider the extent to which management is willing stretch its payout ratio (through aggressive increases or delays in needed decreases) in order to satisfy common shareholders. For a utility that is a subsidiary of a parent company with several utility subsidiaries, dividends to the parent may be more volatile depending on the cash generation and cash needs of that utility, because parents typically want to assure that each utility maintains the regulatory debt/equity ratio on which its rates have been set. The effect we have observed is that utility subsidiaries often pay higher dividends when they have lower capital needs and lower dividends when they have higher capital expenditures or other cash needs. Any dividend policy that cuts into the regulatory debt/equity ratio is a material credit negative.

Size – Natural Disasters, Customer Concentration and Construction Risks

The size and scale of a regulated utility has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. While size brings certain economies of scale that can somewhat affect the utility's cost structure and competitiveness, rates are more heavily impacted by costs related to fuel and fixed assets. Particularly in the US, we have not observed material differences in the success of utilities' regulatory outreach based on their size. Smaller utilities have sometimes been better able to focus their attention on meeting the expectations of a single regulator than their multi-state peers.

However, size can be a very important factor in our assessment of certain risks that impact ratings, including exposure to natural disasters, customer concentration (primarily to industrial customers in a single sector) and construction risks associated with large projects. While the grid attempts to incorporate the first two of these into Factor 3, for some issuers these considerations may be sufficiently important that the rating reflects a greater weight for these risks. While construction projects always carry the risk of cost over-runs and delays, these risks are materially heightened for projects that are very large relative to the size of the utility.

Interaction of Utility Ratings with Government Policies and Sovereign Ratings

Compared to most industrial sectors, regulated utilities are more likely to be impacted by government actions. Credit impacts can occur directly through rate regulation, and indirectly through energy, environmental and tax policies. Government actions affect fuel prices, the mix of generating plants, the certainty and timing of revenues and costs, and the likelihood that regulated utilities will experience financial stress. While our evolving view of the impact of such policies and the general economic and financial climate is reflected in ratings for each utility, some considerations do not lend themselves to incorporation in a simple ratings grid.[12]

Diversified Operations at the Utility

A small number of regulated utilities have diversified operations that are segments within the utility company, as opposed to the more common practice of housing such operations in one or more separate affiliates. In general, we will seek to evaluate the other businesses that are material in accordance with the appropriate methodology and the rating will reflect considerations from such methodologies. There may be analytical limitations in evaluating the utility and non-utility businesses when segment financial results are not fully broken out and these may be addressed through estimation based on available information. Since regulated utilities are a relatively low risk business compared to other corporate sectors, in most cases diversified non-utility operations increase the business risk profile of a utility. Reflecting this tendency, we note that assigned ratings are typically lower than grid-indicated ratings for such companies.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include mergers and acquisitions, asset sales, spin-offs, capital restructuring programs, litigation and shareholder distributions.

[12] See also the cross-sector methodology How Sovereign Credit Quality May Affect Other Ratings, February 2012.

Corporate Governance

Among the areas of focus in corporate governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, and ownership structure.

Investment and Acquisition Strategy

In our credit assessment we take into consideration management's investment strategy. Investment strategy is benchmarked with that of the other companies in the rated universe to further verify its consistency. Acquisitions can strengthen a company's business. Our assessment of a company's tolerance for acquisitions at a given rating level takes into consideration (1) management's risk appetite, including the likelihood of further acquisitions over the medium term; (2) share buy-back activity; (3) the company's commitment to specific leverage targets; and (4) the volatility of the underlying businesses, as well as that of the business acquired. Ratings can often hold after acquisitions even if leverage temporarily climbs above normally acceptable ranges. However, this depends on (1) the strategic fit; (2) pro-forma capitalization/leverage following an acquisition; and (3) our confidence that credit metrics will be restored in a relatively short timeframe.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. Such accuracy is only possible when companies have sufficient internal controls, including centralized operations, the proper tone at the top and consistency in accounting policies and procedures.

Weaknesses in the overall financial reporting processes, financial statement restatements or delays in regulatory filings can be indications of a potential breakdown in internal controls.

Conclusion: Summary of the Grid-Indicated Rating Outcomes

For the 45 representative utilities shown in the illustrative mapping examples, the grid-indicated ratings map to current assigned ratings as follows (see Appendix B for the details):

» 33% or 15 companies map to their assigned rating

» 49% or 22 companies have grid-indicated ratings that are within one alpha-numeric notch of their assigned rating

» 16% or 7 companies have grid-indicated ratings that are within two alpha-numeric notches of their assigned rating

» 2% or 1 company has a grid-indicated rating that is within three alpha-numeric notches of its assigned rating

Grid Indicated Rating Outcomes

Map to Assigned Rating	Map to Within One Notch
American Electric Power Company, Inc.	Appalachian Power Company
China Longyuan Power Group Corporation Ltd.	Arizona Public Service Company
Chubu Electric Power Company, Incorporated	China Resources Gas Group Limited
Entergy Corporation	Duke Energy Corporation
FortisBC Holdings Inc.	Florida Power & Light Company
Great Plains Energy Incorporated	Georgia Power Company
Hokuriku Electric Power Company	Hawaiian Electric Industries, Inc.
Madison Gas & Electric	Idaho Power Company
MidAmerican Energy Company	Kansai Electric Power Company, Incorporated
Mississippi Power Company	Korea Electric Power Corporation
Newfoundland Power Inc.	MidAmerican Energy Holdings Co.
Oklahoma Gas and Electric Company	Niagara Mohawk Power Corporation
Osaka Gas Co., Ltd.	Northern States Power Minnesota
Saudi Electricity	Okinawa Electric Power Company, Incorporated
Wisconsin Public Service Corporation	PacifiCorp
	Pennsylvania Electric Company
	PNG Companies
	Public Service Company of New Mexico
	SCANA
	Southwestern Public Service Company
	UGI Utilities, Inc.
	Virginia Electric Power Company

Map to Within Two Notches	Map to Within Three or More Notches
Ameren Illinois Company	Western Mass Electric Co.
Consumers Energy Company	
Distribuidora de Electricidad La Paz S.A.	
Empresa Electrica de Guatemala, S.A. (EEGSA)	
Gail (India) Ltd	
Gas Natural Ban, S.A.	
Ohio Power Company	

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1_ within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward -looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward -looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.5%		≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
CFO pre-WC / Debt	15%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.5%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Appendix B: Regulated Electric and Gas Utilities – Assigned Ratings and Grid-Indicated Ratings for a Selected Cross-Section of Issuers

	Issuer	Outlook	Actual Rating	*BCA / Rating Before Uplift* [13]	Grid Indicated Rating	Country
1	Ameren Illinois Company	RUR-Up	Baa2	-	A3	USA
2	American Electric Power Company, Inc.	RUR-Up	Baa2	-	Baa2	USA
3	Appalachian Power Company	RUR-Up	Baa2	-	Baa1	USA
4	Arizona Public Service Company	RUR-Up	Baa1	-	A3	USA
5	China Longyuan Power Group Corporation	Stable	Baa3	*Ba1*	Ba1	China
6	China Resources Gas Group Ltd.	Stable	Baa1	*Baa2*	Baa1	China
7	Chubu Electric Power Company, Inc.	Negative	A3	*Baa2*	Baa2	Japan
8	Consumers Energy Company	RUR-Up	(P)Baa1	-	A2	USA
9	Distribuidora de Electricidad La Paz S.A.	Stable	Ba3	-	Ba1	Bolivia
10	Duke Energy Corporation	RUR-Up	Baa1	-	Baa2	USA
11	Empresa Electrica de Guatemala, S.A.	Positive	Ba2	-	Baa3	Guatemala
12	Entergy Corporation	Stable	Baa3	-	Baa3	USA
13	Florida Power & Light Company	RUR-Up	A2	-	A1	USA
14	FortisBC Holdings Inc.	Negative	Baa2	-	Baa2	Canada
15	Gail (India) Ltd	Stable	Baa2	*Baa2*	A3	India
16	Gas Natural BAN, S.A.	Negative	B3	-	B1	Argentina
17	Georgia Power Company	Stable	A3	-	A2	USA
18	Great Plains Energy Incorporated	RUR-Up	Baa3	-	Baa3	USA
19	Hawaiian Electric Industries, Inc.	RUR-Up	Baa2	-	Baa1	USA
20	Hokuriku Electric Power Company	Negative	A3	*Baa2*	Baa2	Japan
21	Idaho Power Company	RUR-Up	Baa1	-	A3	USA
22	Kansai Electric Power Company, Inc.	Negative	A3	*Baa2*	Baa3	Japan
23	Korea Electric Power Corporation	Stable	A1	*Baa2*	Baa3	Korea
24	Madison Gas & Electric	RUR-Up	A1	-	A1	USA
25	MidAmerican Energy Company	RUR-Up	A2	-	A2	USA
26	MidAmerican Energy Holdings Co.	RUR-Up	Baa1	-	A3	USA
27	Mississippi Power Company	Stable	Baa1	-	Baa1	USA
28	Niagara Mohawk Power Corporation	RUR-Up	A3	-	A2	USA
29	Newfoundland Power Inc.	Stable	Baa1	-	Baa1	Canada
30	Northern States Power Minnesota	RUR-Up	A3	-	A2	USA
31	Ohio Power Company	Stable	Baa1	-	A2	USA
32	Okinawa Electric Power Company, Inc.	Stable	Aa3	*A2*	A3	Japan
33	Oklahoma Gas & Electric Company	RUR-Up	A2	-	A2	USA
34	Osaka Gas Co., Ltd.	Stable	Aa3	*A1*	A1	Japan

[13] BCA means a Baseline Credit Assessment for a government related issuer. Please see Government Related Issuers: Methodology Update, July 2010. In addition, certain companies in Japan receive a ratings uplift due to country-specific considerations. Please see "Support system for large corporate entities in Japan can provide ratings uplift, with limits" in Appendix G.

	Issuer	Outlook	Actual Rating	*BCA / Rating Before Uplift*[13]	Grid Indicated Rating	Country
35	PacifiCorp	RUR-Up	Baa1	-	A3	USA
36	Pennsylvania Electric Company	Stable	Baa2	-	Baa1	USA
37	PNG Companies LLC	RUR-Up	Baa3	-	Baa2	USA
38	Public Service Company of New Mexico	RUR-Up	Baa3	-	Baa2	USA
39	Saudi Electricity Company	Stable	A1	*Baa1*	Baa1	Saudi Arabia
40	SCANA Corporation	Stable	Baa3	-	Baa2	USA
41	Southwestern Public Service Company	RUR-Up	Baa2	-	Baa1	USA
42	UGI Utilities, Inc.	RUR-Up	A3	-	A2	USA
43	Virginia Electric and Power Company	RUR-Up	A3	-	A2	USA
44	Western Massachusetts Electric Company	RUR-Up	Baa2	-	A2	USA
45	Wisconsin Public Service Corporation	RUR-Up	A2	-	A2	USA

Appendix C: Regulated Electric and Gas Utility Grid Outcomes and Outlier Discussion

In the table below positive or negative "outliers" for a given sub-factor are defined as issuers whose grid sub-factor score is at least two broad rating categories higher or lower than a company's rating (e.g. a B-rated company whose rating on a specific sub-factor is in the Baa-rating category is flagged as a positive outlier for that sub-factor). Green is used to denote a positive outlier, whose grid-indicated performance for a sub-factor is two or more broad rating categories higher than Moody's rating. Red is used to denote a negative outlier, whose grid-indicated performance for a sub-factor is two or more broad rating categories lower than Moody's rating.

Grid-Indicated Ratings

					Factor 1a	Factor 1b		Factor 2a	Factor 2b		Factor 3a	Factor 3b		Factor 4a	Factor 4b	Factor 4c	Factor 4d	Hold-Co Notching for Structural Subor-dination
		Actual Rating / *BCA or Rating Before Uplift*	Indicated Rating	Indicated Factor 1 Rating	12.50 %	12.50 %	Indicated Factor 2 Rating	12.50 %	12.50 %	Indicated Factor 3 Rating	5.00 %	5.00 %	Indicated Factor 4 Rating	7.50 %	15.00 %	10.00 %	7.50 %	
1	Ameren Illinois Company	Baa2	A3	Baa	A	Baa	Baa	Aa	Ba	Baa	Baa	-	A	Baa	A	Baa	Aa	n/a
2	American Electric Power Company, Inc.	Baa2	Baa2	A	A	A	Baa	A	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	-1
3	Appalachian Power Company	Baa2	Baa1	A	A	A	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	n/a
4	Arizona Public Service Company	Baa1	A3	A	A	A	Baa	A	Baa	Baa	Baa	Baa	A	A	A	A	A	n/a
5	China Longyuan Power Group Corporation Ltd.	Baa3 / *Ba1*	Ba1	Ba	Ba	Baa	A	Baa	A	Baa	Baa	A	Ba	Ba	Ba	Baa	B	-1
6	China Resources Gas Group Limited	Baa1 / *Baa2*	Baa1	Ba	Ba	Baa	Ba	Ba	Baa	Baa	Baa	-	A	Aaa	A	A	A	n/a
7	Chubu Electric Power Company, Incorporated	A3 / *Baa2*	Baa2	A	Aa	Baa	Baa	Ba	A	Baa	A	Ba	Ba	Aa	Ba	Ba	B	n/a
8	Consumers Energy Company	Baa1	A2	A	A	Aa	A	Aa	A	Ba	Baa	Ba	A	A	A	A	Baa	n/a
9	Distribuidora de Electricidad La Paz S.A.	Ba3	Ba1	B	B	Ba	B	B	Ba	B	B	-	A	Baa	A	A	A	n/a
10	Duke Energy Corp.	Baa1	Baa2	A	A	Aa	Baa	A	Baa	A	A	A	Baa	A	Baa	Baa	A	-2
11	Empresa Electrica de Guatemala, S.A. (EEGSA)	Ba2	Baa3	Ba	Ba	Ba	Ba	Ba	Ba	Ba	Ba	-	Baa	A	Aa	B	A	n/a
12	Entergy Corp	Baa3	Baa3	Baa	A	Baa	Baa	Baa	Baa	A	A	Baa	A	A	A	A	Baa	-2
13	Florida Power & Light Company	A2	A1	A	A	Aa	A	Aa	Baa	A	A	A	Aa	Aaa	Aa	Aa	Aa	n/a
14	FortisBC Holdings Inc.	Baa2	Baa2	A	A	A	A	A	A	A	A	-	Ba	Ba	Ba	Ba	Ba	0
15	Gail (India) Ltd	Baa2 / *Baa2*	A3	Ba	Ba	Ba	Baa	Baa	Baa	Ba	Ba	-	Aa	Aaa	Aaa	Aaa	Aa	n/a
16	Gas Natural Ban, S.A.	B3	B1	Caa	Caa	Caa	Caa	Caa	Caa	B	B	-	A	Ba	A	Baa	Aaa	n/a

Grid-Indicated Ratings

		Actual Rating / *BCA or Rating Before Uplift*	Indicated Rating	Indicated Factor 1 Rating	Factor 1a 12.50 %	Factor 1b 12.50 %	Indicated Factor 2 Rating	Factor 2a 12.50 %	Factor 2b 12.50 %	Indicated Factor 3 Rating	Factor 3a 5.00 %	Factor 3b 5.00 %	Indicated Factor 4 Rating	Factor 4a 7.50 %	Factor 4b 15.00 %	Factor 4c 10.00 %	Factor 4d 7.50 %	Hold-Co Notching for Structural Subor-dination
17	Georgia Power Company	A3	A2	Aa	Aa	Aa	A	Aa	Baa	Baa	Baa	Baa	A	Aa	A	Baa	A	n/a
18	Great Plains Energy Incorporated	Baa3	Baa3	A	A	A	Ba	Baa	Ba	Ba	Baa	Ba	Baa	Baa	Baa	Baa	Baa	-1
19	Hawaiian Electric Industries, Inc.	Baa2	Baa1	A	A	A	A	Aa	A	Ba	Baa	Ba	Baa	A	Baa	Baa	Baa	-1
20	Hokuriku Electric Power Company	A3 / *Baa2*	Baa2	A	Aa	Baa	Baa	Ba	A	Ba	Baa	Ba	Ba	Aa	Ba	Ba	B	n/a
21	Idaho Power Company	Baa1	A3	A	A	A	A	Aa	Baa	Baa	Baa	A	Baa	Baa	Baa	Baa	A	n/a
22	Kansai Electric Power Company, Incorporated	A3 / *Baa2*	Baa3	A	Aa	Baa	Baa	Ba	A	Baa	A	Ba	B	Ba	B	Ba	Caa	n/a
23	Korea Electric Power Corporation	A1 / *Baa2*	Baa3	Baa	Baa	Baa	Ba	Ba	Ba	A	A	A	Ba	Ba	Ba	Ba	Baa	n/a
24	Madison Gas & Electric	A1	A1	A	A	Aa	A	Aa	Baa	Baa	Baa	Baa	Aa	Aa	Aa	Aa	A	n/a
25	MidAmerican Energy Company	A2	A2	A	A	Aa	Ba	Ba	Baa	Baa	Baa	A	A	Aa	A	Aa	A	n/a
26	MidAmerican Energy Holdings Co.	Baa1	A3	A	A	A	Baa	Baa	Baa	A	A	Baa	Baa	Baa	Baa	A	Baa	0
27	Mississippi Power Company	Baa1	Baa1	A	A	A	A	Aa	Baa	Ba	Baa	Ba	Baa	A	Baa	Baa	Baa	n/a
28	Niagara Mohawk Power Corporation	A3	A2	A	A	A	A	Aa	Baa	Baa	Baa	-	A	Aa	A	A	Aa	n/a
29	Newfoundland Power Inc.	Baa1	Baa1	A	A	A	A	A	A	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	n/a
30	Northern States Power Minnesota	A3	A2	A	A	A	A	Aa	Baa	Baa	Baa	Baa	A	A	A	A	A	n/a
31	Ohio Power Company	Baa1	A2	A	A	A	Baa	Baa	A	Ba	Baa	B	A	A	Aa	A	A	n/a
32	Okinawa Electric Power Company, Incorporated	Aa3 / *A2*	A3	Aa	Aa	Aa	A	A	A	Ba	Ba	Ba	Baa	Aaa	Ba	Baa	B	n/a
33	Oklahoma Gas and Electric Company	A2	A2	A	A	Aa	Baa	Baa	A	Baa	Baa	Baa	A	A	A	A	A	n/a
34	Osaka Gas Co., Ltd.	Aa3 / *A1*	A1	Aa	Aa	Aa	A	A	A	A	A	-	A	Aaa	A	A	A	n/a
35	PacifiCorp	Baa1	A3	A	A	A	Baa	Aa	Ba	Baa	A	Baa	A	A	A	Baa	A	n/a
36	Pennsylvania Electric Company	Baa2	Baa1	A	A	A	Baa	A	Baa	Baa	Baa	-	Baa	Baa	Baa	Ba	A	n/a

Grid-Indicated Ratings

		Actual Rating / *BCA or Rating Before Uplift*	Indicated Rating	Indicated Factor 1 Rating	Factor 1a 12.50 %	Factor 1b 12.50 %	Indicated Factor 2 Rating	Factor 2a 12.50 %	Factor 2b 12.50 %	Indicated Factor 3 Rating	Factor 3a 5.00 %	Factor 3b 5.00 %	Indicated Factor 4 Rating	Factor 4a 7.50 %	Factor 4b 15.00 %	Factor 4c 10.00 %	Factor 4d 7.50 %	Hold-Co Notching for Structural Subor-dination
37	PNG Companies	Baa3	Baa2	A	A	A	Ba	Baa	Ba	Baa	Baa	-	Ba	Ba	Ba	Ba	Baa	n/a
38	Public Service Company of New Mexico	Baa3	Baa2	Baa	A	Baa	Ba	Baa	Ba	Baa	Baa	Baa	Baa	A	Baa	A	Baa	n/a
39	Saudi Electricity	A1 / *Baa1*	Baa1	Baa	Baa	A	Ba	Baa	Ba	A	Baa	Aaa	A	Aaa	A	A	Baa	n/a
40	SCANA	Baa3	Baa2	Aa	Aa	Aa	Baa	Baa	Baa	Ba	Baa	Ba	Baa	Baa	Baa	Baa	Baa	-1
41	Southwestern Public Service Company	Baa2	Baa1	A	A	A	Baa	A	Baa	Ba	Ba	Baa	Baa	Baa	Baa	Baa	A	n/a
42	UGI Utilities, Inc.	A3	A2	A	A	A	A	A	A	Baa	Baa	-	A	A	A	A	A	n/a
43	Virginia Electric Power Company	A3	A2	Aa	Aa	Aa	A	Aa	Baa	Baa	Baa	Baa	A	A	A	A	A	n/a
44	Western Mass Electric Co.	Baa2	A2	A	A	Aa	A	A	A	Ba	Ba	-	A	Aa	A	A	A	n/a
45	Wisconsin Public Service Corporation	A2	A2	A	A	Aa	A	Aa	Baa	Baa	Baa	Baa	A	Aa	A	A	A	n/a

Outliers in Legislative and Judicial Underpinnings of the Regulatory Framework

For Chubu Electric Power Company, Hokuriku Electric Power Company, Kansai Electric Power Company, and Okinawa Electric Power Company, our ratings consider the credit-supportive underpinnings in the Electric Utility Industries Law that have been balanced against higher leverage and lower returns than global peers.

For SCANA Corporation, the South Carolina Base Load Review Act provides strong credit support for companies engaging in nuclear new-build, which also affects the scoring for consistency and predictability of regulation. However, SCANA's rating also considers the size and complexity of the nuclear construction project, which is out of scale to the size of the company, as well as structural subordination.

Outliers in Consistency and Predictability of Regulation

Consumers Energy Company has benefitted from increasingly predictable regulatory decisions in Michigan, as well as improved timeliness due to forward test years and the ability to implement interim rates. However, the substantial debt at its parent, CMS Energy Corporation (Baa3, RUR-up), has weighed on the ratings.

Duke Energy Corporation has received generally consistent and predictable rate treatment at it subsidiary operating companies, but parent debt has impacted financial metrics

The shift in business mix at Western Massachusetts Electric Company will place a greater percentage of its rate base under the jurisdiction of the FERC, generally viewed as having greater consistency and predictability, which is somewhat tempered by its financial metrics.

Outliers in Timeliness of Recovery of Operating and Capital Costs

Ameren Illinois Company has a formula rate plan that has a positive impact on timeliness, balanced against rate decisions that have been somewhat below average.

Hawaiian Electric Industries, Inc.'s timeliness has improved considerably due to the introduction in rate-making of a de-coupling mechanism, forward test year and an investment tracker at its utility subsidiary.

For Mississippi Power Company, a fully forward test year and the ability to recover some construction-work-in-progress in rates lead to strong scoring for timeliness. Ratings also consider risks associated with construction of a power plant that will utilize lignite and integrated gasification combined cycle technology, that has experienced material costs overruns and that represents a high degree of asset concentration for the utility.

For MidAmerican Energy Company, the absence of a fuel cost pass-through mechanism at the time of this writing results in its relatively low scoring on timeliness. However, the company has proposed a fuel clause in its current rate case, and the regulatory framework has generally been quite credit supportive, which has helped the utility generate good financial metrics.

The primary utility divisions of PacifiCorp have forward test years that have a positive impact on timeliness, balanced against rate decisions that have been somewhat below average.

Outliers in Sufficiency of Rates and Returns

China Longyuan Power Group Corporation Ltd. has benefitted from a higher benchmark tariff for its wind power generation, balanced against a less well developed regulatory framework.

Outliers in Market Position

Okinawa Electric Power Company, Incorporated's service territory is a group of small islands with limited economic diversity, which negatively impacts its market position. Generation is highly dependent on coal and oil. These factors are balanced against a strong regulatory framework.

Outliers in Generation and Fuel Diversity

Ohio Power Company has been highly dependent on coal-fired generation but will be divesting generation assets in accordance with regulatory initiatives.

Outliers in Financial Strength

Distribuidora de Electricidad La Paz S.A. has strong historical financial metrics that are balanced against the somewhat unpredictable regulatory framework and the risk of government intervention in its business.

Gail (India) Limited has strong historical financial metrics that are balanced against higher business risk in its diversified, non-rate-regulated operations, including in oil and gas exploration and production. Financial metrics are expected to weaken somewhat relative to historical levels due to debt funded capex and are thus expected to be more in line with its rating going forward.

Gas Natural BAN S.A. has strong historical financial metrics that are expected to deteriorate due to frozen tariff positions, reflected in weak scores for the regulatory environment. Its ratings are also impacted by debt maturities that are concentrated in the short term and the Government of Argentina's B3 negative rating.

Appendix D: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. Financing of these entities varies by region, in part due to the regulatory framework. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries or minority interests in other companies. However, in certain cases there may be material operations at the HoldCo level. Financing can occur primarily at the OpCo level, primarily at the HoldCo level, or at both HoldCo and OpCos in varying proportions. When a HoldCo has multiple utility OpCos, they will often be located in different regulatory jurisdictions. A HoldCo may have both levered and unlevered OpCos.

General Approach to a Utility Family

In our analysis, we generally consider the stand-alone credit profile of an OpCo and the credit profile of its ultimate parent HoldCo (and any intermediate HoldCos), as well as the profile of the family as a whole, while acknowledging that these elements can have cross-family credit implications in varying degrees, principally based on the regulatory framework of the OpCos and the financing model (which has often developed in response to the regulatory framework).

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[14] approach a HoldCo rating by assessing the qualitative and quantitative factors in this methodology for the consolidated entity and each of its utility subsidiaries. Ratings of individual entities in the issuer family may be pulled up or down based on the interrelationships among the companies in the family and their relative credit strength.

In considering how closely aligned or how differentiated ratings should be among members of a utility family, we assess a variety of factors, including:

- Regulatory or other barriers to cash movement among OpCos and from OpCos to HoldCo
- Differentiation of the regulatory frameworks of the various OpCos
- Specific ring-fencing provisions at particular OpCos
- Financing arrangements – for instance, each OpCo may have its own financing arrangements, or the sole liquidity facility may be at the parent; there may be a liquidity pool among certain but not all members of the family; certain members of the family may better be able to withstand a temporary hiatus of external liquidity or access to capital markets
- Financial covenants and the extent to which an Event of Default by one OpCo limits availability of liquidity to another member of the family
- The extent to which higher leverage at one entity increases default risk for other members of the family
- An entity's exposure to or insulation from an affiliate with high business risk

[14] See paragraph at the end of this section for approaches to Hybrid HoldCos.

» Structural features or other limitations in financing agreements that restrict movements of funds, investments, provision of guarantees or collateral, etc.

» The relative size and financial significance of any particular OpCo to the HoldCo and the family

See also those factors noted in Notching for Structural Subordination of Holding Companies.

Our approach to a Hybrid HoldCo (see definition in Appendix E) depends in part on the importance of its non-utility operations and the availability of information on individual businesses. If the businesses are material and their individual results are fully broken out in financial disclosures, we may be able to assess each material business individually by reference to the relevant Moody's methodologies to arrive at a composite assessment for the combined businesses. If non-utility operations are material but are not broken out in financial disclosures, we may look at the consolidated entity under more than one methodology. When non-utility operations are less material but could still impact the overall credit profile, the difference in business risks and our estimation of their impact on financial performance will be qualitatively incorporated in the rating.

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

Where higher barriers to cash movement exist on an OpCo or OpCos due the regulatory framework or debt structural features, ratings among family members are likely to be more differentiated. For instance, for utility families with OpCos in the US, where regulatory barriers to free cash movement are relatively high, greater importance is generally placed on the stand-alone credit profile of the OpCo.

Our observation of major defaults and bankruptcies in the US sector generally corroborates a view that regulation creates a degree of separateness of default probability. For instance, Portland General Electric (Baa1 RUR-up) did not default on its securities, even though its then-parent Enron Corp. entered bankruptcy proceedings. When Entergy New Orleans (Ba2 stable) entered into bankruptcy, the ratings of its affiliates and parent Entergy Corporation (Baa3 stable) were unaffected. PG&E Corporation (Baa1 stable) did not enter bankruptcy proceedings despite bankruptcies of two major subsidiaries - Pacific Gas & Electric Company (A3 stable) in 2001 and National Energy Group in 2003.

The degree of separateness may be greater or smaller and is assessed on a case by case basis, because situational considerations are important. One area we consider is financing arrangements. For instance, there will tend to be greater differentiation if each member of a family has its own bank credit facilities and difficulties experienced by one entity would not trigger events of default for other entities. While the existence of a money pool might appear to reduce separateness between the participants, there may be regulatory barriers within money pools that preserve separateness. For instance, non-utility entities may have access to the pool only as a borrower, only as a lender, and even the utility entities may have regulatory limits on their borrowings from the pool or their credit exposures to other pool members. If the only source of external liquidity for a money pool is borrowings by the HoldCo under its bank credit facilities, there would be less separateness, especially if the utilities were expected to depend on that liquidity source. However, the ability of an OpCo to finance itself by accessing capital markets must also be considered. Inter-company tax agreements can also have an impact on our view of how separate the risks of default are.

For a HoldCo, the greater the regulatory, economic, and geographic diversity of its OpCos, the greater its potential separation from the default probability of any individual subsidiary. Conversely, if a HoldCo's actions have made it clear that the HoldCo will provide support for an OpCo encountering

some financial stress (for instance, due to delays and/or cost over-runs on a major construction project), we would be likely to perceive less separateness.

Even where high barriers to cash movement exist, onerous leverage at a parent company may not only give rise to greater notching for structural subordination at the parent, it may also pressure an OpCo's rating, especially when there is a clear dependence on an OpCo's cash flow to service parent debt. While most of the regulatory barriers to cash movement are very real, they are not absolute. Furthermore, while it is not usually in the interest of an insolvent parent or its creditors to bring an operating utility into a bankruptcy proceeding, such an occurrence is not impossible.

The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring-fencing provisions that fully separate the management and operations of the OpCo from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers. Currently, most entities in US utility families (including HoldCos and OpCos) are rated within 3 notches of each other. However, Energy Future Holdings Corp. (Caa3 senior unsecured) and its T&D subsidiary Oncor Electric Delivery Company LLC (Baa3 senior secured) have much wider notching due to the combination of regulatory imperatives and strong ring-fencing that includes a significant minority shareholder who must agree to important corporate decisions, including a voluntary bankruptcy filing.

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

Our approach to rating issuers within a family where there are lower regulatory barriers to movement of cash from OpCos to HoldCos (e.g., many parts of Asia and Europe) places greater emphasis on the credit profile of the consolidated group. Individual OpCos are considered based on their individual characteristics and their importance to the family, and their assigned ratings are typically banded closely around the consolidated credit profile of the group due to the expectation that cash will transit relatively freely among family entities.

Some utilities may have OpCos in jurisdictions where cash movement among certain family members is more restricted by the regulatory framework, while cash movement from and/or among OpCos in other jurisdictions is less restricted. In these situations, OpCos with more restrictions may vary more widely from the consolidated credit profile while those with fewer restrictions may be more tightly banded around the other entities in the corporate family group.

Appendix E: Brief Descriptions of the Types of Companies Rated Under This Methodology

The following describes the principal categories of companies rated under this methodology:

Vertically Integrated Utility: Vertically integrated utilities are regulated electric or combination utilities (see below) that own generation, distribution and (in most cases) electric transmission assets. Vertically integrated utilities are generally engaged in all aspects of the electricity business. They build power plants, procure fuel, generate power, build and maintain the electric grid that delivers power from a group of power plants to end-users (including high and low voltage lines, transformers and substations), and generally meet all of the electric needs of the customers in a specific geographic area (also called a service territory). The rates or tariffs for all of these monopolistic activities are set by the relevant regulatory authority.

Transmission & Distribution Utility: Transmission & Distribution utilities (T&Ds) typically operate in deregulated markets where generation is provided under a competitive framework. T&Ds own and operate the electric grid that transmits and/or distributes electricity within a specific state or region. T&Ds provide electrical transportation and distribution services to carry electricity from power plants and transmission lines to retail, commercial, and industrial customers. T&Ds are typically responsible for billing customers for electric delivery and/or supply, and most have an obligation to provide a standard supply or provider-of-last-resort (POLR) service to customers that have not switched to a competitive supplier. These factors distinguish T&Ds from Networks, whose customers are retail electric suppliers and/or other electricity companies. In a smaller number of cases, T&Ds rated under this methodology may not have an obligation to provide POLR services, but are regulated in sub-sovereign jurisdictions. The rates or tariffs for these monopolistic T&D activities are set by the relevant regulatory authority.

Local Gas Distribution Company: Distribution is the final step in delivering natural gas to customers. While some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity pipelines that carry gas from gas producing basins to areas where gas is consumed, most other users receive natural gas from their local gas utility, also called a local distribution company (LDC). LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area. Specifically, LDCs typically transport natural gas from delivery points located on large-diameter pipelines (that usually operate at fairly high pressure) to households and businesses through thousands of miles of small-diameter distribution pipe (that usually operate at fairly low pressure). LDCs are typically responsible for billing customers for gas delivery and/or supply, and most also have the responsibility to procure gas for at least some of their customers, although in some markets gas supply to all customers is on a competitive basis. These factors distinguish LDCs from gas networks, whose customers are retail gas suppliers and/or other natural gas companies. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Integrated Gas Utility: Integrated gas regulated utilities are regulated utilities that deliver gas to all end users in a particular service territory by sourcing the commodity; operating transport infrastructure that often combines high pressure pipelines with low pressure distribution systems and, in some cases, gas storage, re-gasification or other related facilities; and performing other supply-related activities, such as customer billing and metering. The rates or tariffs for the totality of these activities are set by the relevant regulatory authority. Many integrated gas utilities are national in scope.

Combination Utility: Combination utilities are those that combine an LDC or Integrated Gas Utility with either a vertically integrated utility or a T&D utility. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Regulated Generation Utility: Regulated generation utilities (Regulated Gencos) are utilities that almost exclusively have generation assets, but their activities are generally regulated like those of vertically integrated utilities. In the US, this means that the purchasers of their output (typically other investor-owned, municipal or cooperative utilities) pay a regulated rate based on the total allowed costs of the Regulated Genco, including a return on equity based on a capital structure designated by the regulator (primarily FERC). Companies that have been included in this group include certain generation companies (including in Korea and China) that are not rate regulated in the usual sense of recovering costs plus a regulated rate of return on either equity or asset value. Instead, we have looked at a combination of governmental action with respect to setting feed-in tariffs and directives on how much generation will be built (or not built) in combination with a generally high degree of government ownership, and we have concluded that these companies are currently best rated under this methodology. Future evolution in our view of the operating and/or regulatory environment of these companies could lead us to conclude that they may be more appropriately rated under a related methodology (for example, Unregulated Utilities and Power Companies).

Independent System Operator: An Independent System Operator (ISO) is an organization formed in certain regional electricity markets to act as the sole chief coordinator of an electric grid. In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system to assure that electric supply and demand are balanced at all times, and, to the extent possible, that electric demand is met with the lowest-cost sources. ISOs seek to assure adequate transmission and generation resources, usually by identifying new transmission needs and planning for a generation reserve margin above expected peak demand. In regions where generation is competitive, they also seek to establish rules that foster a fair and open marketplace, and they may conduct price-setting auctions for energy and/or capacity. The generation resources that an ISO coordinates may belong to vertically integrated utilities or to independent power producers. ISOs may not be rate-regulated in the traditional sense, but fall under governmental oversight. All participants in the regional grid are required to pay a fee or tariff (often volumetric) to the ISO that is designed to recover its costs, including costs of investment in systems and equipment needed to fulfill their function. ISOs may be for profit or not-for-profit entities.

In the US, most ISOs were formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), but the ISO that operates solely in Texas falls under state jurisdiction. Some US ISOs also perform certain additional functions such that they are designated as Regional Transmission Organizations (or RTOs).

Transmission-Only Utility: Transmission-only utilities are solely focused on owning and operating transmission assets. The transmission lines these utilities own are typically high-voltage and allow energy producers to transport electric power over long distances from where it is generated (or received) to the transmission or distribution system of a T&D or vertically integrated utility. Unlike most of the other utilities rated under this methodology, transmission-only utilities primarily provide services to other utilities and ISOs. Transmission-only utilities in most parts of the world other than the US have been rated under the Regulated Networks methodology, and we expect that FERC-regulated transmission-only utilities in the US will also transition to the Regulated Networks when that methodology is updated (expected in 2014).

Utility Holding Company (Utility HoldCo): As detailed in Appendix D, regulated electric and gas utilities are often part of corporate families under a parent holding company. The operating subsidiaries of Utility Holdcos are overwhelmingly regulated electric and gas utilities.

Hybrid Holding Company (Hybrid HoldCo): Some utility families contain a mix of regulated electric and gas utilities and other types of companies, but the regulated electric and gas utilities represent the majority of the consolidated cash flows, assets and debt. The parent company is thus a Hybrid HoldCo.

Appendix F: Key Industry Issues Over the Intermediate Term

Political and Regulatory Issues

As highly regulated monopolistic entities, regulated utilities continually face political and regulatory risk, and managing these risks through effective outreach to key customers as well as key political and regulatory decision-makers is, or at least should be, a core competency of companies in this sector. However, larger waves of change in the political, regulatory or economic environment have the potential to cause substantial changes in the level of risk experienced by utilities and their investors in somewhat unpredictable ways.

One of the more universal risks faced by utilities currently is the compression of allowed returns. A long period of globally low interest rates, held down by monetary stimulus policies, has generally benefitted utilities, since reductions in allowed returns have been slower than reductions in incurred capital costs. Essentially all regulated utilities face a ratcheting down of allowed and/or earned returns. More difficult to predict is how regulators will respond when monetary stimulus reverses, and how well utilities will fare when fixed income investors require higher interest rates and equity investors require higher total returns and growth prospects.

The following global snapshot highlights that regulatory frameworks evolve over time. On an overall basis in the US over the past several years, we have noted some incremental positive regulatory trends, including greater use of formula rates, trackers and riders, and (primarily for natural gas utilities) de-coupling of returns from volumetric sales. In Canada, the framework has historically been viewed as predictable and stable, which has helped offset somewhat lower levels of equity in the capital structure, but the compression of returns has been relatively steep in recent years. In Japan, the regulatory authorities are working through the challenges presented by the decision to shut down virtually all of the country's nuclear generation capacity, leading to uncertainty regarding the extent to which increased costs will be reflected in rate increases sufficient to permit returns on capital to return to prior levels. China's regulatory framework has continued to evolve, with fairly low transparency and some time-to-time shifts in favored versus less-favored generation sources balanced by an overall state policy of assuring sustainability of the sector, adequate supply of electricity and affordability to the general public. Singapore and Hong Kong have fairly well developed and supportive regulatory frameworks despite a trend towards lower returns, whereas Malaysia, Korea and Thailand have been moving towards a more transparent regulatory framework. The Philippines is in the process of deregulating its power market, while Indian power utilities continue to grapple with structural challenges. In Latin America, there is a wide dispersion among frameworks, ranging from the more stable, long established and predictable framework in Chile to the decidedly unpredictable framework in Argentina. Generally, as Latin American economies have evolved to more stable economic policies, regulatory frameworks for utilities have also shown greater stability and predictability.

All of the other issues discussed in this section have a regulatory/political component, either as the driver of change or in reaction to changes in economic environments and market factors.

Economic and Financial Market Conditions

As regulated monopolies, electric and gas utilities have generally been quite resistant to unsettled economic and financial market conditions for several reasons. Unlike many companies that face direct market-based competition, their rates do not decrease when demand decreases. The elasticity of demand for electricity and gas is much lower than for most products in the consumer economy. When financial markets are volatile, utilities often have greater capital market access than industrial companies in competitive sectors, as was the case in the 2007-2009 recession. However, regulated electric and gas utilities are by no means immune to a protracted or severe recession.

Severe economic malaise can negatively affect utility credit profiles in several ways. Falling demand for electricity or natural gas may negatively impact margins and debt service protection measures, especially when rates are designed such that a substantial portion of fixed costs is in theory recovered through volumetric charges. The decrease in demand in the 2007-2009 recession was notable in comparison to prior recessions, especially in the residential sector. Poor economic conditions can make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, recessions can coincide with a lack of confidence in the utility sector that impacts access to capital markets for a period of time. For instance, in the Great Depression and (to a lesser extent) in the 2001 recession, access for some issuers was curtailed due to the sector's generally higher leverage than other corporate sectors, combined with a concerns over a lack of transparency in financial reporting.

Fuel Price Volatility and the Global Impact of Shale Gas

The ability of most utilities to pass through their fuel costs to end users may insulate a utility from exposure to price volatility of these fuels, but it does not insulate consumers. Consumers and regulators complained vociferously about utility rates during the run-up in hydro-carbon prices in 2005-2008 (oil, natural gas and, to a lesser extent, coal). The steep decline in US natural gas prices since 2009, caused in large part by the development of shale gas and shale oil resources, has been a material benefit to US utilities, because many have been able to pass through substantial base rate increases during a period when all-in rates were declining. Shale hydro-carbons have also had a positive impact, albeit one that is less immediate and direct, on non-US utilities. In much of the eastern hemisphere, natural gas prices under long-term contracts have generally been tied to oil prices, but utilities and other industrial users have started to have some success in negotiating to de-link natural gas from oil. In addition, increasing US production of oil has had a noticeable impact on world oil prices, generally benefitting oil and gas users.

Not all utilities will benefit equally. Utilities that have locked in natural gas under high-priced long-term contracts that they cannot re-negotiate are negatively impacted if they cannot pass through their full contracted cost of gas, or if the high costs cause customer dissatisfaction and regulatory backlash. Utilities with large coal fleets or utilities constructing nuclear power plants may also face negative impacts on their regulatory environment, since their customers will benefit less from lower natural gas prices.

Distributed Generation Versus the Central Station Paradigm

The regulation and the financing of electric utilities are based on the premise that the current model under which electricity is generated and distributed to customers will continue essentially unchanged for many decades to come. This model, called the central station paradigm (because electricity is generated in large, centrally located plants and distributed to a large number of customers, who may in fact be hundreds of miles away), has been in place since the early part of the 20th century. The model has worked because the economies of scale inherent to very large power plants has more than offset the cost and inefficiency (through power losses) inherent to maintaining a grid for transmitting and distributing electricity to end users.

Despite rate structures that only allow recovery of invested capital over many decades (up to 60 years), utilities can attract capital because investors assume that rates will continue to be collected for at least that long a period. Regulators and politicians assume that taxes and regulatory charges levied on electricity usage will be paid by a broad swath of residences and businesses and will not materially discourage usage of electricity in a way that would decrease the amount of taxes collected. A corollary

assumption is that the number of customers taking electricity from the system during that period will continue to be high enough such that rates will be reasonable and generally more attractive than other alternatives. In the event that consumers were to switch en masse to alternate sources of generating or receiving power (for instance distributed generation), rates for remaining customers would either not cover the utility's costs, or rates would need to be increased so much that more customers may be incentivized to leave the system. This scenario has been experienced in the regulated US copper wire telephone business, where rates have increased quite dramatically for users who have not switched to digital or wireless telephone service. While this scenario continues to be unlikely for the electricity sector, distributed generation, especially from solar panels, has made inroads in certain regions.

Distributed generation is any retail-scale generation, differentiated from self-generation, which generally describes a large industrial plant that builds its own reasonably large conventional power plant to meet its own needs. While some residential property owners that install distributed generation may choose to sever their connection to the local utility, most choose to remain connected, generating power into the grid when it is both feasible and economic to do so, and taking power from the grid at other times. Distributed generation is currently concentrated in roof-top photovoltaic solar panels, which have benefitted from varying levels of tax incentives in different jurisdictions. Regulatory treatment has also varied, but some rate structures that seek to incentivize distributed renewable energy are decidedly credit negative for utilities, in particular net metering.

Under net metering, a customer receives a credit from the utility for all of its generation at the full (or nearly full) retail rate and pays only for power taken, also at the retail rate, resulting in a materially reduced monthly bill relative to a customer with no distributed generation. The distributed generation customer has no obligation to generate any particular amount of power, so the utility must stand ready to generate and deliver that customer's full power needs at all times. Since most utility costs, including the fixed costs of financing and maintaining generation and delivery systems, are currently collected through volumetric rates, a customer owning distributed generation effectively transfers a portion of the utility's costs of serving that customer to other customers with higher net usage, notably to customers that do not own distributed generation. The higher costs may incentivize more customers to install solar panels, thereby shifting the utility's fixed costs to an even smaller group of rate-payers. California is an example of a state employing net solar metering in its rate structure, whereas in New Jersey, which has the second largest residential solar program in the US, utilities buy power at a price closer to their blended cost of generation, which is much lower than the retail rate.

To date, solar generation and net metering have not had a material credit impact on any utilities, but ratings could be negatively impacted if the programs were to grow and if rate structures were not amended so that each customer's monthly bill more closely approximated the cost of serving that customer.

In our current view, the possibility that there will be a widespread movement of electric utility customers to sever themselves from the grid is remote. However, we acknowledge that new technologies, such as the development of commercially viable fuel cells and/or distributed electric storage, could materially disrupt the central station paradigm and the credit quality of the utility sector.

Nuclear Issues

Utilities with nuclear generation face unique safety, regulatory, and operational issues. The nuclear disaster at Fukushima Daiichi had a severely negative credit impact on its owner, Tokyo Electric Power Company, Incorporated (Ba3, negative), as well as all the nuclear utilities in the country. Japan previously generated about 30% of its power from 50 reactors, but all are currently either idled or shut down, and utilities in the country face materially higher costs of replacement power, a credit negative. Japan also created a new Nuclear Regulation Authority (NRA), under the Ministry of the Environment to replace the Nuclear Safety Commission, which had been under the Ministry of Economy, Trade and Industry. The NRA has not yet set any schedule for completing safety checks at idled plants.

Fukushima Daiichi also had global consequences. Germany's response was to require that all nuclear power plants in the country be shut by 2022. Switzerland opted for a phase-out by 2031. (Most European nuclear plants are owned by companies rated under other the Unregulated Utilities and Power Companies methodology.) Even in countries where the regulatory response was more moderate, increased regulatory scrutiny has raised operating costs, a credit negative, especially in the US, where low natural gas prices have rendered certain primarily smaller nuclear plants uneconomic. Nuclear license renewal decisions in the US are currently on hold until the Nuclear Regulatory Commission comes to a determination on the safety of spent fuel storage in the absence of a permanent repository. Nonetheless, we view robust and independent nuclear safety regulation as a credit-positive for the industry.

Other general issues for nuclear operators include higher costs and lower reliability related to the increasing age of the fleet. In 2013, Duke Energy Florida, Inc. (Baa1, RUR-up) decided to permanently shut Crystal River Unit 3 after it determined that a de-lamination (or separation) in the concrete of the outer wall of the containment building was uneconomic to repair. San Onofre Nuclear Generating Station was permanently closed in 2013 after its owners, including Southern California Edison Company (A3, RUR-up) and San Diego Gas & Electric Company (A2, RUR-up), decided not to pursue a re-start in light of operating defects in two steam generators that had been replaced in 2010 and 2011.

Korea Hydro and Nuclear Power Company Limited (KHNP, A1 stable) and its parent Korea Electric Power Corporation (KEPCO, A1 stable), face a scandal related to alleged corruption and acceptance of falsified safety documents provided by its parts suppliers for nuclear plants. Korean prosecutors' widening probe into KHNP's use of substandard parts at many of its 23 nuclear power plants caused three plants to be temporarily shut down starting in May 2013 and raises the risk the Korean public will lose confidence in nuclear power. However, more than 80% of substandard parts in the idled plants have been replaced, and a restart is expected in late 2013 or early 2014.

Appendix G: Regional and Other Considerations

Notching Considerations for US First Mortgage Bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance in the publication Updated Summary Guidance for Notching Bonds, Preferred Stocks and Hybrid Securities of Corporate Issuers, February 2007), including a one notch differential between senior secured and senior unsecured debt. However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US.

Wider notching differentials between debt classes may also be appropriate in speculative grade. Additional insights for speculative grade issuers are provided in the publication Loss Given Default for Speculative-Grade Non-Financial Companies in the US, Canada and EMEA, June 2009).

First mortgage bond holders in the US generally benefit from a first lien on most of the fixed assets used to provide utility service, including such assets as generating stations, transmission lines, distribution lines, switching stations and substations, and gas distribution facilities, as well as a lien on franchise agreements. In our view, the critical nature of these assets to the issuers and to the communities they serve has been a major factor that has led to very high recovery rates for this class of debt in situations of default, thereby justifying a two notch uplift. The combination of the breadth of assets pledged and the bankruptcy-tested recovery experience has been unique to the US.

In some cases, there is only a one notch differential between US first mortgage bonds and the senior unsecured rating. For instance, this is likely when the pledged property is not considered critical infrastructure for the region, or if the mortgage is materially weakened by carve-outs, lien releases or similar creditor-unfriendly terms.

Securitization

The use of securitization, a financing technique utilizing a discrete revenue stream (typically related to recovery of specifically defined expenses) that is dedicated to servicing specific securitization debt, has primarily been used in the US, where it has been quite pervasive in the past two decades. The first generation of securitization bonds were primarily related to recovery of the negative difference between the market value of utilities' generation assets and their book value when certain states switched to competitive electric supply markets and utilities sold their generation (so-called stranded costs). This technique was then used for significant storm costs (especially hurricanes) and was eventually broadened to include environmental related expenditures, deferred fuel costs, or even deferred miscellaneous expenses. States that have implemented securitization frameworks include Arkansas, California, Connecticut, Illinois, Louisiana, Maryland, Massachusetts, Mississippi, New Hampshire, New Jersey, Ohio, Pennsylvania, Texas and West Virginia. In its simplest form, a securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitization is typically underpinned by specific legislation to segregate the securitization revenues from the utility's revenues to assure their continued collection, and the details of the enabling legislation may vary from state to state. The utility benefits from the securitization because it receives an immediate source of cash (although it gives up the opportunity to earn a return on the corresponding asset), and ratepayers benefit because the cost of the securitized debt is lower than the utility's cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery.

In the presentation of US securitization debt in published financial ratios, Moody's makes its own assessment of the appropriate credit representation but in most cases follows the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which is in turn considers the terms of enabling legislation. As a result, accounting treatment may vary. In most states utilities have been required to consolidate securitization debt under GAAP, even though it is technically non-recourse.

In general, we view securitization debt of utilities as being on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, we seek to adjust the company's ratios by including the securitization debt and related revenues for our analysis. Where the securitized debt is on balance sheet, our credit analysis also considers the significance of ratios that exclude securitization debt and related revenues. Since securitization debt amortizes mortgage-style, including it makes ratios look worse in early years (when most of the revenue collected goes to pay interest) and better in later years (when most of the revenue collected goes to pay principal).

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership have dominated the credit profiles of utilities in Asia Pacific (excluding Japan), generally leading to ratings that are a number of notches above the Baseline Credit Assessment. Regulated electric and gas utilities with significant government ownership are rated using this methodology in conjunction with the Joint Default Analysis approach in our methodology for Government-Related Issuers.

Support system for large corporate entities in Japan can provide ratings uplift, with limits

Moody's ratings for large corporate entities in Japan reflect the unique nature of the country's support system, and they are higher than they would otherwise be if such support were disregarded. This is reflected in the tendency for ratings of Japanese utilities to be higher than their grid implied ratings (currently higher on average by about 2 notches), while utilities globally tend to be more evenly distributed above and below their actual ratings. However, even for large prominent companies, our ratings consider that support will not be endless and is less likely to be provided when a company has questionable viability rather than being in need of temporary liquidity assistance.

Appendix H: Treatment of Power Purchase Agreements ("PPAs")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, to fix the cost of power, or to comply with regulatory mandates regarding power sourcing, including renewable portfolio standards. While Moody's regards PPAs that reduce operating or financial risk as a credit positive, some aspects of PPAs may negatively affect the credit of utilities. The most conservative treatment would be to treat a PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover the IPP's debt service and are made irrespective of whether the utility calls on the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also typically be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus analyzed by Moody's as PPAs.

PPAs are recognized qualitatively to be a future use of cash whether or not they are treated as debt-like obligations in financial ratios

The starting point of our analysis is the issuer's audited financial statements – we consider whether the utility's accountants determine that the PPA should be treated as a debt equivalent, a capitalized lease, an operating lease, or in some other manner. PPAs have a wide variety of operational and financial terms, and it is our understanding that accountants are required to have a very granular view into the particular contractual arrangements in order to account for these PPAs in compliance with applicable accounting rules and standards. However, accounting treatment for PPAs may not be entirely consistent across US GAAP, IFRS or other accounting frameworks. In addition, we may consider that factors not incorporated into the accounting treatment may be relevant (which may include the scale of PPA payments, their regulatory treatment including cost recovery mechanisms, or other factors that create financial or operational risk for the utility that is greater, in our estimation, than the benefits received). When the accounting treatment of a PPA is a debt or lease equivalent (such that it is reported on the balance sheet, or disclosed as an operating lease and thus included in our adjusted debt calculation), we generally do not make adjustments to remove the PPA from the balance sheet. However, in relevant circumstances we consider making adjustments that impute a debt equivalent to PPAs that are off-balance sheet for accounting purposes.

Regardless of whether we consider that a PPA warrants or does not warrant treatment as a debt obligation, we assess the totality of the impact of the PPA on the issuer's probability of default. Costs of a PPA that cannot be recovered in retail rates creates material risk, especially if they also cannot be recovered through market sales of power.

Additional considerations for PPAs

PPAs have a wide variety of financial and regulatory characteristics, and each particular circumstance may be treated differently by Moody's. Factors which determine where on the continuum Moody's treats a particular PPA include the following:

» Risk management: An overarching principle is that PPAs have normally been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.

» Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive or if regulatory support for cost recovery deteriorates, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly.

» Price considerations: The price of power paid by a utility under a PPA can be substantially above or below the market price of electricity. A below-market price will motivate the utility to purchase power from the IPP in excess of its retail requirements, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or at an above-market price may suffer a financial burden if they do not get full recovery in retail rates. Moody's will particularly focus on PPAs that have mark-to-market losses, which typically indicates that they have a material impact on the utility's cash flow.

» Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. We may determine that all of a utility's PPAs represent excess capacity, or that a portion of PPAs are needed for the utility's supply obligations plus a normal reserve margin, while the remaining portion represents excess capacity. In the latter case, we may impute debt to specific PPAs that are excess or we take a proportional approach to all of the utility's PPAs.

» Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. Moody's will examine on a case-by case basis the relative credit risk associated with PPAs in comparison to plant ownership.

» Purchase requirements: Some PPAs are structured with either options or requirements to purchase the asset at the end of the PPA term. If the utility has an economically meaningful requirement to purchase, we would most likely consider it to be a debt obligation. In most such cases, the obligation would already receive on-balance sheet treatment under relevant accounting standards.

» Default provisions: In most cases, the remedies for default under a PPA do not include acceleration of amounts due, and in many cases PPAs would not be considered as debt in a bankruptcy scenario and could potentially be cancelled. Thus, PPAs may not materially increase Loss Given Default for the utility. In addition, PPAs are not typically considered debt for cross-default provisions under a utility's debt and liquidity arrangements. However, the existence of non-standard default provisions that are debt-like would have a large impact on our treatment of a PPA. In addition, payments due under PPAs are senior unsecured obligations, and any inability of the utility to make them materially increases default risk.

Each of these factors will be considered by Moody's analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods for estimating a liability amount for PPAs

According to the weighting and importance of the PPA to each utility and the level of disclosure, Moody's may approximate a debt obligation equivalent for PPAs using one or more of the methods discussed below. In each case we look holistically at the PPA's credit impact on the utility, including the ability to pass through costs and curtail payments, the materiality of the PPA obligation to the overall business risk and cash flows of the utility, operational constraints that the PPA imposes, the maturity of the PPA obligation, the impact of purchased power on market-based power sales (if any) that the utility will engage in, and our view of future market conditions and volatility.

» Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. Provided that the accounting treatment for the PPA is, in this circumstance, off-balance sheet, we will most likely make no adjustment to bring the obligation onto the utility's balance sheet.

» Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot otherwise be quantified otherwise due to limited information.

» Net Present Value: Where the analyst has sufficient information, Moody's may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be our estimate of the cost of capital of the utility.

» Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.

» Mark-to-Market: In situations in which Moody's believes that the PPA prices exceed the market price and thus will create an ongoing liability for the utility, we may use a net mark-to-market method, in which the NPV of the utility's future out-of-the-money net payments will be added to its total debt obligations.

» Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. If the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

If we have determined to impute debt to a PPA for which the accounting treatment is not on-balance sheet, we will in some circumstances use more than one method to estimate the debt equivalent obligations imposed by the PPA, and compare results. If circumstances (including regulatory treatment or market conditions) change over time, the approach that is used may also vary.

Moody's Related Research

Industry Outlooks:

» US Regulated Utilities: Regulation Provides Stability as Business Model Faces Challenges, July 2013 (156754)

» Asian Power Utilities (ex-Japan): Broad Stable Outlook; India an Outlier, March 2013 (149101)

Rating Methodologies:

» US Electric Generation & Transmission Cooperatives, April 2013, (151814)

» How Sovereign Credit Quality May Affect Other Ratings, February 2012 (139495)

» Unregulated Utilities and Power Companies, August 2009 (118508)

» Regulated Electric and Gas Networks, August 2009 (118786)

» Natural Gas Pipelines, November 2012 (146415)

» US Public Power Electric Utilities with Generation Ownership Exposure, November 2011 (135299)

» US Electric Generation & Transmission Cooperatives, April 2013 (151814)

» US Municipal Joint Action Agencies, October 2012 (145899)

» Government Related Issuers: Methodology Update, July 2010 (126031)

» Global Regulated Water Utilities, December 2009 (121311)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more secondary or cross-sector credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related secondary and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

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MOODY'S INVESTORS SERVICE

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
Form 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2017

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____ to _____
Commission File Number 001-31303

BLACK HILLS CORPORATION

Incorporated in South Dakota	7001 Mount Rushmore Road Rapid City, South Dakota 57702	IRS Identification Number 46-0458824

Registrant's telephone number, including area code
(605) 721-1700

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock of $1.00 par value	New York Stock Exchange

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☒ No ☐

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ☐ No ☒

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☒ No ☐

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).
Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐

Non-accelerated filer ☐ (Do not check if a smaller reporting company)

Smaller reporting company ☐

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the Registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ☐ No ☒

State the aggregate market value of the voting stock held by non-affiliates of the Registrant.

At June 30, 2017 $3,563,087,139

Indicate the number of shares outstanding of each of the Registrant's classes of common stock, as of the latest practicable date.

Class	Outstanding at January 31, 2018
Common stock, $1.00 par value	53,544,761 shares

Documents Incorporated by Reference

Portions of the Registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2018 Annual Meeting of Stockholders to be held on April 24, 2018, are incorporated by reference in Part III of this Form 10-K.

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GLOSSARY OF TERMS AND ABBREVIATIONS

The following terms and abbreviations appear in the text of this report and have the definitions described below:

AC	Alternating Current
AFUDC	Allowance for Funds Used During Construction
AltaGas	AltaGas Renewable Energy Colorado LLC, a subsidiary of AltaGas Ltd.
AOCI	Accumulated Other Comprehensive Income
APSC	Arkansas Public Service Commission
Aquila Transaction	Our July 14, 2008 acquisition of five utilities from Aquila, Inc.
ARO	Asset Retirement Obligations
ASC	Accounting Standards Codification
ASU	Accounting Standards Update as issued by the FASB
ATM	At-the-market equity offering program
Basin Electric	Basin Electric Power Cooperative
Bbl	Barrel
Bcf	Billion cubic feet
BHC	Black Hills Corporation; the Company
BHEP	Black Hills Exploration and Production, Inc., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, includes Black Hills Gas Resources, Inc. and Black Hills Plateau Production LLC, direct wholly-owned subsidiaries of Black Hills Exploration and Production, Inc.
Black Hills Colorado IPP	Black Hills Colorado IPP, LLC a 50.1% owned subsidiary of Black Hills Electric Generation
Black Hills Gas	Black Hills Gas, LLC, a subsidiary of Black Hills Gas Holdings, which was previously named SourceGas LLC.
Black Hills Gas Holdings	Black Hills Gas Holdings, LLC, a subsidiary of Black Hills Utility Holdings, which was previously named SourceGas Holdings LLC
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Black Hills Energy	The name used to conduct the business of our utility companies
Black Hills Energy Arkansas Gas	Includes the acquired SourceGas utility Black Hills Energy Arkansas, Inc. utility operations
Black Hills Energy Colorado Electric	Includes Colorado Electric's utility operations
Black Hills Energy Colorado Gas	Includes Black Hills Energy Colorado Gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Colorado gas operations and RMNG
Black Hills Energy Iowa Gas	Includes Black Hills Energy Iowa gas utility operations
Black Hills Energy Kansas Gas	Includes Black Hills Energy Kansas gas utility operations
Black Hills Energy Nebraska Gas	Includes Black Hills Energy Nebraska gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Nebraska gas operations
Black Hills Energy Services	A Choice Gas supplier acquired in the SourceGas Acquisition
Black Hills Energy South Dakota Electric	Includes Black Hills Power's operations in South Dakota, Wyoming and Montana
Black Hills Energy Wyoming Electric	Includes Cheyenne Light's electric utility operations
Black Hills Energy Wyoming Gas	Includes Cheyenne Light's natural gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Wyoming gas operations
Black Hills Gas Distribution	Black Hills Gas Distribution, LLC, a company acquired in the SourceGas Acquisition that conducts the gas distribution operations in Colorado, Nebraska and Wyoming. It was formerly named SourceGas Distribution LLC.
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Power	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
BHSC	Black Hills Service Company LLC, a direct, wholly-owned subsidiary of Black Hills Corporation

Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
BLM	United States Bureau of Land Management
Busch Ranch	Busch Ranch Wind Farm is a 29 MW wind farm near Pueblo, Colorado, jointly owned by Colorado Electric and AltaGas. Colorado Electric has a 50% ownership interest in the wind farm.
Ceiling Test	Related to our Oil and Gas subsidiary, capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test which limits the pooled costs to the aggregate of the discounted value of future net revenue attributable to proved natural gas and crude oil reserves using a discount rate defined by the SEC plus the lower of cost or market value of unevaluated properties.
CAPP	Customer Appliance Protection Plan - acquired in the SourceGas Acquisition
CFTC	United States Commodity Futures Trading Commission
CG&A	Cawley, Gillespie & Associates, Inc., an independent consulting and engineering firm
Cheyenne Light	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Cheyenne Prairie	Cheyenne Prairie Generating Station is a 132 MW natural-gas fired generating facility jointly owned by Black Hills Power and Cheyenne Light in Cheyenne, Wyoming. Cheyenne Prairie was placed into commercial service on October 1, 2014.
Choice Gas Program	The unbundling of the natural gas service from the distribution component, which opens up the gas supply for competition allowing customers to choose from different natural gas suppliers. Black Hills Gas Distribution distributes the gas and Black Hills Energy Services is one of the Choice Gas suppliers.
City of Gillette	Gillette, Wyoming
Colorado Electric	Black Hills Colorado Electric Utility Company, LP, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
Colorado Gas	Black Hills Colorado Gas Utility Company, LP, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
Colorado Interstate Gas (CIG)	Colorado Interstate Natural Gas Pricing Index
Colorado IPP	Black Hills Colorado IPP, LLC a 50.1% owned subsidiary of Black Hills Electric Generation
Consolidated Indebtedness to Capitalization Ratio	Any Indebtedness outstanding at such time, divided by Capital at such time. Capital being Consolidated Net-Worth (excluding noncontrolling interest and including the aggregate outstanding amount of RSNs) plus Consolidated Indebtedness (including letters of credit, certain guarantees issued and excluding RSNs) as defined within the current Credit Agreement.
Cooling Degree Day	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30-year average.
CPP	Clean Power Plan
CP Program	Commercial Paper Program
CPUC	Colorado Public Utilities Commission
CT	Combustion turbine
CTII	The 40 MW Gillette CT, a simple-cycle, gas-fired combustion turbine owned by the City of Gillette.
CVA	Credit Valuation Adjustment
DART	Days Away Restricted Transferred (number of cases with days away from work or job transfer or restrictions multiplied by 200,000 then divided by total hours worked for all employees during the year covered)
DC	Direct current
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DSM	Demand Side Management
DRSPP	Dividend Reinvestment and Stock Purchase Plan

Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu)
EBITDA	Earnings before interest, taxes, depreciation and amortization, a non-GAAP measurement
ECA	Energy Cost Adjustment -- adjustments that allow us to pass the prudently-incurred cost of fuel and purchased energy through to customers.
Economy Energy	Electricity purchased by one utility from another utility to take the place of electricity that would have cost more to produce on the utility's own system
EIA	Environmental Improvement Adjustment
Energy West	Energy West Wyoming, Inc., a subsidiary of Gas Natural, Inc. Energy West is an acquisition we closed on July 1, 2015.
Enserco	Enserco Energy Inc., a former wholly-owned subsidiary of Black Hills Non-regulated Holdings, which is presented in discontinued operations in this Annual Report filed on Form 10-K
EPA	United States Environmental Protection Agency
Equity Unit	Each Equity Unit has a stated amount of $50, consisting of a purchase contract issued by BHC to purchase shares of BHC common stock and a 1/20, or 5% undivided beneficial ownership interest in $1,000 principal amount of BHC RSNs due 2028.
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FDIC	Federal Depository Insurance Corporation
FERC	United States Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Accounting principles generally accepted in the United States of America
GADS	Generation Availability Data System
GCA	Gas Cost Adjustment -- adjustments that allow us to pass the prudently-incurred cost of gas and certain services through to customers.
GHG	Greenhouse gases
Global Settlement	Settlement with a utilities commission where the dollar figure is agreed upon, but the specific adjustments used by each party to arrive at the figure are not specified in public rate orders
Happy Jack	Happy Jack Wind Farm, LLC, owned by Duke Energy Generation Services
Heating Degree Day	A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations over a 30 year average.
IEEE	Institute of Electrical and Electronics Engineers
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
IPP	Independent power producer
IPP Transaction	The July 11, 2008 sale of seven of our IPP plants
IRS	United States Internal Revenue Service
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
kV	Kilovolt
LIBOR	London Interbank Offered Rate
LOE	Lease Operating Expense
Loveland Area Project	Part of the Western Area Power Association transmission system
MAPP	Mid-Continent Area Power Pool
MATS	Utility Mercury and Air Toxics Rules under the United States EPA National Emissions Standards for Hazardous Air Pollutants from Coal and Oil Fired Electric Utility Steam Generating Units
Mbbl	Thousand barrels of oil

Mcf	Thousand cubic feet
Mcfd	Thousand cubic feet per day

Mcfe	Thousand cubic feet equivalent
MDU	Montana Dakota Utilities Co., a regulated utility division of MDU Resources Group, Inc.
MEAN	Municipal Energy Agency of Nebraska
MGP	Manufactured Gas Plant
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent
Moody's	Moody's Investors Service, Inc.
MSHA	Mine Safety and Health Administration
MTPSC	Montana Public Service Commission
MW	Megawatts
MWh	Megawatt-hours
N/A	Not Applicable
NAV	Net Asset Value
Nebraska Gas	Black Hills Nebraska Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings (doing business as Black Hills Energy)
NERC	North American Electric Reliability Corporation
NGL	Natural Gas Liquids (1 barrel equals 6 Mcfe)
NOAA	National Oceanic and Atmospheric Administration
NOAA Climate Normals	This dataset is produced once every 10 years. This dataset contains daily and monthly normals of temperature, precipitation, snowfall, heating and cooling degree days, frost/freeze dates, and growing degree days calculated from observations at approximately 9,800 stations operated by NOAA's National Weather Service.
NO_x	Nitrogen oxide
NOL	Net operating loss
NPSC	Nebraska Public Service Commission
NWPL	Northwest Interstate Natural Gas Pricing Index
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OSHA	Occupational Safety & Health Administration
OSM	U.S. Department of the Interior's Office of Surface Mining
PCA	Power Cost Adjustment
PCCA	Power Capacity Cost Adjustment
Peak View	$109 million 60 MW wind generating project owned by Colorado Electric, placed in service on November 7, 2016 and adjacent to Busch Ranch Wind Farm
PPA	Power Purchase Agreement
PUHCA 2005	Public Utility Holding Company Act of 2005
REPA	Renewable Energy Purchase Agreement
Revolving Credit Facility	Our $750 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which matures in 2021
RMNG	Rocky Mountain Natural Gas, a regulated gas utility acquired in the SourceGas Acquisition that provides regulated transmission and wholesale natural gas service to Black Hills Gas Distribution in western Colorado (doing business as Black Hills Energy)
RSNs	Remarketable junior subordinated notes, issued on November 23, 2015

SAIDI	System Average Interruption Duration Index
SDPUC	South Dakota Public Utilities Commission
SEC	U. S. Securities and Exchange Commission
Service Guard	Home appliance repair product offering for both natural gas and electric
Silver Sage	Silver Sage Windpower, LLC, owned by Duke Energy Generation Services
SO_2	Sulfur dioxide

S&P	Standard & Poor's, a division of The McGraw-Hill Companies, Inc.
SourceGas	SourceGas Holdings LLC and its subsidiaries, a gas utility owned by funds managed by Alinda Capital Partners and GE Energy Financial Services, a unit of General Electric Co. (NYSE:GE) that was acquired on February 12, 2016, and is now named Black Hills Gas Holdings, LLC (doing business as Black Hills Energy)
SourceGas Acquisition	The acquisition of SourceGas Holdings, LLC by Black Hills Utility Holdings
SourceGas Transaction	On February 12, 2016, Black Hills Utility Holdings acquired SourceGas pursuant to a purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in debt at closing.
South Dakota Electric	Includes Black Hills Power operations in South Dakota, Wyoming, and Montana
SSIR	System Safety and Integrity Rider
System Peak Demand	Represents the highest point of customer usage for a single hour for the system in total. Our system peaks include demand loads for 100% of plants regardless of joint ownership.
TCA	Transmission Cost Adjustment -- adjustments passed through to the customer based on transmission costs that are higher or lower than the costs approved in the rate case.
TCJA	Tax Cuts and Jobs Act enacted on December 22, 2017
TCIR	Total Case Incident Rate (average number of work-related injuries incurred by 100 workers during a one-year period)
Tech Services	Non-regulated product lines within Black Hills Corporation that 1) provide electrical system construction services to large industrial customers of our electric utilities, and 2) serve gas transportation customers throughout its service territory by constructing and maintaining customer-owner gas infrastructure facilities, typically through one-time contracts.
TFA	Transmission Facility Adjustment
VEBA	Voluntary Employee Benefit Association
VIE	Variable Interest Entity
WDEQ	Wyoming Department of Environmental Quality
WECC	Western Electricity Coordinating Council
Winter Storm Atlas	An October 2013 blizzard that impacted South Dakota Electric. It was the second most severe blizzard in Rapid City's history.
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings
Wyodak Plant	Wyodak, a 362 MW mine-mouth coal-fired plant in Gillette, Wyoming, owned 80% by PacifiCorp and 20% by Black Hills Energy South Dakota. Our WRDC mine supplies all of the fuel for the plant.
Wyoming Electric	Includes Cheyenne Light's electric utility operations
Wyoming Gas	Includes Cheyenne Light's natural gas utility operations, as well as the acquired SourceGas utility Black Hills Gas Distribution's Wyoming gas operations

Website Access to Reports

The reports we file with the SEC are available free of charge at our website www.blackhillscorp.com as soon as reasonably practicable after they are filed. In addition, the charters of our Audit, Governance and Compensation Committees are located on our website along with our Code of Business Conduct, Code of Ethics for our Chief Executive Officer and Senior Finance Officers, Corporate Governance Guidelines of the Board of Directors and Policy for Director Independence. The information contained on our website is not part of this document.

Forward-Looking Information

This Form 10-K contains forward-looking statements as defined by the SEC. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words “anticipates,” “estimates,” “expects,” “intends,” “plans,” “predicts” and similar expressions, and include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 7 - Management’s Discussion & Analysis of Financial Condition and Results of Operations.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company’s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including without limitation, management’s examination of historical operating trends, data contained in the Company’s records and other data available from third parties. Nonetheless, the Company’s expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Form 10-K, including statements contained within Item 1A - Risk Factors.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

History and Organization

Black Hills Corporation, a South Dakota corporation (together with its subsidiaries, referred to herein as the “Company,” “we,” “us” or “our”), is a customer-focused, growth-oriented, vertically-integrated utility company headquartered in Rapid City, South Dakota. Our predecessor company, Black Hills Power and Light Company, was incorporated and began providing electric utility service in 1941. It was formed through the purchase and combination of several existing electric utilities and related assets, some of which had served customers in the Black Hills region since 1883. In 1956, with the purchase of the Wyodak Coal Mine, we began producing and selling energy through non-regulated businesses.

We operate our business in the United States, reporting our operating results through our regulated Electric Utilities, regulated Gas Utilities, Power Generation and Mining segments. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other.

Our Electric Utilities segment generates, transmits and distributes electricity to approximately 210,000 electric customers in South Dakota, Wyoming, Colorado and Montana. Our Electric Utilities own 941 MW of generation and 8,839 miles of electric transmission and distribution lines. For additional information, see the Key Elements of our Business Strategy in Item 7.

Our Gas Utilities segment serves approximately 1,042,000 natural gas utility customers in Arkansas, Colorado, Iowa, Nebraska, Kansas and Wyoming. Our Gas Utilities own and operate 4,656 miles of intrastate gas transmission pipelines and 40,455 miles of gas distribution mains and service lines, seven natural gas storage sites, over 45,000 horsepower of compression and nearly 600 miles of gathering lines. On February 12, 2016, we acquired SourceGas Holdings, LLC, adding four regulated natural gas utilities serving approximately 431,000 customers in Arkansas, Colorado, Nebraska and Wyoming. For additional information

on this acquisition, see the Key Elements of our Business Strategy in Item 7 and Note 2 in the Notes to Consolidated Financial Statements in Item 8.

Our Power Generation segment produces electric power from its generating plants and sells the electric capacity and energy primarily to our utilities under long-term contracts. Our Mining segment produces coal at our mine near Gillette, Wyoming, and sells the coal primarily under long-term contracts to mine-mouth electric generation facilities including our own regulated and non-regulated generating plants. For additional information, see the Key Elements of our Business Strategy in Item 7.

Our segments generated the following income from continuing operations available for common stock for the year ended December 31, 2017 and had the following total assets at December 31, 2017 (excluding Corporate and Other):

	Income (loss) from continuing operations available for common stock for the year ended December 31, 2017	Total Assets as of December 31, 2017
	(in thousands)	
Electric Utilities	$110,082	$2,906,275
Gas Utilities	$65,795	$3,426,466
Power Generation	$46,479	$60,852
Mining	$14,386	$65,455

On November 1, 2017, the BHC board of directors approved a complete divestiture of our Oil and Gas segment. As of February 23, 2018, we have either closed transactions or signed contracts to sell more than 90 percent of our oil and gas properties. We have executed agreements to sell all our operated properties and have only non-operated assets with minimal value left to divest. We plan to conclude the sale of all of our remaining assets by mid-year 2018. The results of our Oil and Gas segment are reflected in discontinued operations, other than certain general and administrative and interest costs. BHEP's assets and liabilities are classified as held for sale. See Note 21 in the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Segment Financial Information

We discuss our business strategy and other prospective information in Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations. Financial information regarding our business segments is incorporated herein by reference to Item 8 - Financial Statements and Supplementary Data, and particularly Note 5 in the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

Electric Utilities Segment

We conduct electric utility operations through our South Dakota, Wyoming and Colorado subsidiaries. Our Electric Utilities generate, transmit and distribute electricity to approximately 210,000 customers in South Dakota, Wyoming, Colorado and Montana. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates. We also provide non-regulated services through our Tech Services product lines.

Capacity and Demand. System peak demands for the Electric Utilities for each of the last three years are listed below:

	System Peak Demand (in MW)					
	2017		2016		2015	
	Summer	Winter	Summer	Winter	Summer	Winter
South Dakota Electric	447	402	438	389	424	369
Wyoming Electric [(a)]	249	230	236	230	212	202
Colorado Electric [(b)]	398	299	412	302	392	303
Total Electric Utilities' Peak Demands	1,094	931	1,086	921	1,028	874

(a) The July 2017 summer peak load of 249 surpassed previous summer peak record load of 236 set in July 2016. The winter peak record of 230 was set in December 2016.

(b) The July 2016 summer peak load of 412 surpassed previous summer peak record load of 406 set in June 2016.

Regulated Power Plants. As of December 31, 2017, our Electric Utilities' ownership interests in electric generation plants were as follows:

Unit	Fuel Type	Location	Ownership Interest %	Owned Capacity (MW)	Year Installed
South Dakota Electric:					
Cheyenne Prairie [(a)]	Gas	Cheyenne, Wyoming	58%	55.0	2014
Wygen III [(b)]	Coal	Gillette, Wyoming	52%	57.2	2010
Neil Simpson II	Coal	Gillette, Wyoming	100%	90.0	1995
Wyodak [(c)]	Coal	Gillette, Wyoming	20%	72.4	1978
Neil Simpson CT	Gas	Gillette, Wyoming	100%	40.0	2000
Lange CT	Gas	Rapid City, South Dakota	100%	40.0	2002
Ben French Diesel #1-5	Oil	Rapid City, South Dakota	100%	10.0	1965
Ben French CTs #1-4	Gas/Oil	Rapid City, South Dakota	100%	80.0	1977-1979
Wyoming Electric:					
Cheyenne Prairie [(a)]	Gas	Cheyenne, Wyoming	42%	40.0	2014
Cheyenne Prairie CT [(a)]	Gas	Cheyenne, Wyoming	100%	37.0	2014
Wygen II	Coal	Gillette, Wyoming	100%	95.0	2008
Colorado Electric:					
Busch Ranch Wind Farm [(d)]	Wind	Pueblo, Colorado	50%	14.5	2012
Peak View Wind Farm [(e)]	Wind	Pueblo, Colorado	100%	60.0	2016
Pueblo Airport Generation	Gas	Pueblo, Colorado	100%	180.0	2011
Pueblo Airport Generation CT [(f)]	Gas	Pueblo, Colorado	100%	40.0	2016
AIP Diesel	Oil	Pueblo, Colorado	100%	10.0	2001
Diesel #1-5	Oil	Pueblo, Colorado	100%	10.0	1964
Diesel #1-5	Oil	Rocky Ford, Colorado	100%	10.0	1964
Total MW Capacity				941.1	

(a) Cheyenne Prairie, a 132 MW natural gas-fired power generation facility, was placed into commercial operation on October 1, 2014, to support the utility customers of South Dakota Electric and Wyoming Electric. The facility includes one simple-cycle, 37 MW combustion turbine that is wholly-owned by Wyoming Electric and one combined-cycle, 95 MW unit that is jointly-owned by Wyoming Electric (40 MW) and South Dakota Electric (55 MW).

(b) Wygen III, a 110 MW mine-mouth coal-fired power plant, is operated by South Dakota Electric. South Dakota Electric has a 52% ownership interest, MDU owns 25% and the City of Gillette owns the remaining 23% interest. Our WRDC coal mine supplies all of the fuel for the plant.

(c) Wyodak, a 362 MW mine-mouth coal-fired power plant, is owned 80% by PacifiCorp and 20% by South Dakota Electric. This baseload plant is operated by PacifiCorp and our WRDC coal mine supplies all of the fuel for the plant.

(d) Busch Ranch Wind Farm, a 29 MW wind farm, is operated by Colorado Electric. Colorado Electric has a 50% ownership interest in the wind farm and AltaGas owns the remaining 50%. Colorado Electric has a 25-year REPA with AltaGas for their 14.5 MW of power from the wind farm.

(e) Peak View Wind Farm achieved commercial operation on November 7, 2016.

(f) Colorado Electric's 40 MW combustion turbine achieved commercial operation on December 29, 2016.

The Electric Utilities' annual average cost of fuel utilized to generate electricity and the average price paid for purchased power (excluding contracted capacity) per MWh for the years ended December 31 is as follows:

Fuel Source (dollars per MWh)	2017	2016	2015
Coal	$ 10.95	$ 11.27	$ 10.89
Natural Gas	$ 34.05	$ 30.59	$ 51.14
Diesel Oil [(a)]	$ 210.11	$ 149.13	$ 303.16
Total Average Fuel Cost	$ 12.80	$ 12.99	$ 14.62
Purchased Power - Coal, Gas and Oil	$ 45.63	$ 48.36	$ 47.81
Purchased Power - Renewable Sources	$ 53.08	$ 51.95	$ 50.92

(a) Included in the Price per MWh for Diesel Oil are unit start-up costs. The diesel-fueled generating units are generally used as supplemental peaking units and the cost per MWh is reflective of how often the units are started and how long the units are run.

Our Electric Utilities' power supply, by resource as a percent of the total power supply for our energy needs for the years ended December 31 is as follows:

Power Supply	2017	2016	2015
Coal	32%	33%	33%
Gas, Oil and Wind	8	7	4
Total Generated	40	40	37
Purchased [(a)]	60	60	63
Total	100%	100%	100%

(a) Wind represents approximately 6%, 7% and 5% of our purchased power in 2017, 2016, and 2015, respectively.

Purchased Power. We have executed various agreements to support our Electric Utilities' capacity and energy needs beyond our regulated power plants' generation. Key contracts include:

- South Dakota Electric's PPA with PacifiCorp expiring on December 31, 2023, which provides for the purchase of 50 MW of coal-fired baseload power;
- Colorado Electric's PPA with Black Hills Colorado IPP expiring on December 31, 2031, which provides 200 MW of energy and capacity to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines. This PPA is reported and accounted for as a capital lease within our business segments and is eliminated on the accompanying Consolidated Financial Statements;
- Colorado Electric's PPA with AltaGas expiring on October 16, 2037, which provides up to 14.5 MW of wind energy from AltaGas' owned interest in the Busch Ranch Wind Farm;
- Wyoming Electric's PPA with Black Hills Wyoming expiring on December 31, 2022, whereby Black Hills Wyoming provides 60 MW of unit-contingent capacity and energy from its Wygen I facility. The PPA includes an option for Wyoming Electric to purchase Black Hills Wyoming's ownership interest in the Wygen I facility through 2019, subject to WPSC and FERC approval in order to obtain regulatory treatment. The purchase price related to the option is $2.6 million per MW (65 MWs), adjusted for all depreciated capital additions since 2009, and reduced by depreciation (approximately $5 million per year) over a 35-year life beginning January 1, 2009. The net book value of Wygen I at December 31, 2017 was $69 million and if Wyoming Electric had exercised the purchase option at year-end 2017, the estimated purchase price would have been approximately $133 million;
- Wyoming Electric's 20-year PPA with Duke Energy expiring on September 3, 2028, which provides up to 29.4 MW of wind energy from the Happy Jack Wind Farm to Wyoming Electric. Under a separate intercompany agreement,

Wyoming Electric sells 50% of the facility's output to South Dakota Electric;

- Wyoming Electric's 20-year PPA with Duke Energy expiring on September 30, 2029, which provides up to 30 MW of wind energy from the Silver Sage wind farm to Wyoming Electric. Under a separate intercompany agreement, Wyoming Electric sells 20 MW of the facility's output to South Dakota Electric; and

- Wyoming Electric and South Dakota Electric's Generation Dispatch Agreement requires South Dakota Electric to purchase all of Wyoming Electric's excess energy.

Power Sales Agreements. Our Electric Utilities have various long-term power sales agreements. Key agreements include:

- MDU owns a 25% interest in Wygen III's net generating capacity for the life of the plant. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, South Dakota Electric will provide MDU with 25 MW from its other generation facilities or from system purchases with reimbursement of costs by MDU;

- South Dakota Electric has an agreement through December 31, 2023 to provide MDU capacity and energy up to a maximum of 50 MW;

- The City of Gillette owns a 23% interest in Wygen III's net generating capacity for the life of the plant. During periods of reduced production at Wygen III, or during periods when Wygen III is off-line, South Dakota Electric will provide the City of Gillette with its first 23 MW from its other generation facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, South Dakota Electric will also provide the City of Gillette its operating component of spinning reserves; and

- South Dakota Electric has an agreement to supply up to 20 MW of energy and capacity to MEAN under a contract that expires in 2023. The terms of the contract run from June 1 through May 31 for each interval listed below. This contract is unit-contingent based on the availability of our Neil Simpson II and Wygen III plants, with decreasing capacity purchased over the term of the agreement. The unit-contingent capacity amounts from Wygen III and Neil Simpson II are as follows:

2018	20 MW - 10 MW contingent on Wygen III and 10 MW contingent on Neil Simpson II
2018-2020	15 MW - 10 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II
2020-2022	12 MW - 6 MW contingent on Wygen III and 6 MW contingent on Neil Simpson II
2022-2023	10 MW - 5 MW contingent on Wygen III and 5 MW contingent on Neil Simpson II

- South Dakota Electric has an agreement from January 1, 2017 through December 31, 2021 to provide 50 MW of energy to Cargill (assigned to Macquarie on January 3, 2018) during heavy and light load timing intervals.

Transmission and Distribution. Through our Electric Utilities, we own electric transmission systems composed of high voltage transmission lines (greater than 69 kV) and low voltage lines (69 kV or less). We also jointly own high voltage lines with Basin Electric and Powder River Energy Corporation.

At December 31, 2017, our Electric Utilities owned the electric transmission and distribution lines shown below:

Utility	State	Transmission (in Line Miles)	Distribution (in Line Miles)
South Dakota Electric	South Dakota, Wyoming	1,264	2,506
South Dakota Electric - Jointly Owned [(a)]	South Dakota, Wyoming	44	—
Wyoming Electric	South Dakota, Wyoming	49	1,281
Colorado Electric	Colorado	602	3,093

(a) South Dakota Electric owns 35% of a DC transmission tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids serving the western United States and eastern United States, respectively. This transmission tie, which is 65% owned by Basin Electric, provides transmission access to both the WECC region in the West and the MAPP region in the East. The transfer capacity of the tie is 200 MW from West to East, and 200 MW from East to West. South Dakota Electric's electric system is located in the WECC region. This transmission tie allows us to buy and sell energy in the Eastern grid without having to isolate and physically reconnect load or generation between the two transmission grids, thus enhancing the reliability of our system. It accommodates scheduling transactions in both directions simultaneously, provides additional opportunities to sell excess generation or

to make economic purchases to serve our native load and contract obligations, and enables us to take advantage of power price differentials between the two grids.

South Dakota Electric has firm point-to-point transmission access to deliver up to 50 MW of power on PacifiCorp's transmission system to wholesale customers in the WECC region through 2023.

South Dakota Electric also has firm network transmission access to deliver power on PacifiCorp's system to Sheridan, Wyoming, to serve our power sales contract with MDU through December 31, 2023, with the right to renew pursuant to the terms of PacifiCorp's transmission tariff.

In order to serve Wyoming Electric's existing load, Wyoming Electric has a network transmission agreement with Western Area Power Association's Loveland Area Project.

Colorado Electric is party to a joint dispatch agreement between Colorado Electric, Public Service Company of Colorado "PSCo" and Platte River Power Authority. This FERC-approved agreement, effective in 2017, is structured to allow PSCo, as administrator, to receive load and generation bid information for all three parties and, on an intra-hour basis, serve the combined utility load utilizing the combined bid generating resources on a least-cost basis. In other words, if one party has excess generation at a lower cost than another party's generation, the administrator will increase dispatch of the lower-cost generation and decrease dispatch of the higher-cost generation. This results in lower energy costs to customers through more efficient dispatch of low-cost generating resources. Under the agreement, Colorado Electric retains the ability to participate or not participate in the joint dispatch at its discretion.

Operating Agreements. Our Electric Utilities have the following material operating agreements:

- Shared Services Agreements -
    - South Dakota Electric, Wyoming Electric, and Black Hills Wyoming are parties to a shared facilities agreement, whereby each entity charges for the use of assets by the affiliate entity.
    - Black Hills Colorado IPP and Colorado Electric are also parties to a facility fee agreement, whereby Colorado Electric charges Black Hills Colorado IPP for the use of Colorado Electric assets.
    - South Dakota Electric and Wyoming Electric receive certain staffing and management services from BHSC for Cheyenne Prairie.
- Jointly Owned Facilities -
    - South Dakota Electric, the City of Gillette and MDU are parties to a shared joint ownership agreement, whereby South Dakota Electric charges the City of Gillette and MDU for administrative services, plant operations and maintenance for their share of the Wygen III generating facility for the life of the plant.
    - Colorado Electric and AltaGas are parties to a shared joint ownership agreement whereby Colorado Electric charges AltaGas for operations and maintenance for their share of the Busch Ranch Wind Farm.

Seasonal Variations of Business. Our Electric Utilities are seasonal businesses and weather patterns may impact their operating performance. Demand for electricity is sensitive to seasonal cooling, heating and industrial load requirements, as well as market price. In particular, demand is often greater in the summer and winter months for cooling and heating, respectively. Because our Electric Utilities have a diverse customer and revenue base, and we have historically optimized the utilization of our electric power supply resources, the impact on our operations may not be as significant when weather conditions are warmer in the winter and cooler in the summer.

Competition. We generally have limited competition for the retail generation and distribution of electricity in our service areas. Various restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate. These initiatives would be aimed at increasing competition or providing for distributed generation. To date, these initiatives have not had a material impact on our utilities. In Colorado, our electric utility is subject to rules which may require competitive bidding for generation supply. Because of these rules, we face competition from other utilities and non-affiliated independent power producers for the right to provide electric energy and capacity for Colorado Electric when resource plans require additional resources.

Rates and Regulation. Our Electric Utilities are subject to the jurisdiction of the public utilities commissions in the states where they operate. The commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. The public utility commissions determine the rates we are allowed to charge for our utility services. Rate decisions are influenced by many factors, including the cost of providing service, capital expenditures, the prudence of costs we incur, views concerning appropriate rates of return, the rates of other utilities, general economic conditions and the political environment. Certain commissions also have jurisdiction over the issuance of debt or securities, and the creation of liens on property located in their states to secure bonds or other securities. The following table provides regulatory information for each of our electric utilities:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Additional Tariffed Mechanisms	Percentage of Power Marketing Profit Shared with Customers
South Dakota Electric	WY	9.9%	8.13%	46.7%/53.3%	$46.8	10/2014	ECA	65%
	SD	Global Settlement	7.76%	Global Settlement	$543.9	10/2014	ECA, TCA, Energy Efficiency Cost Recovery/DSM	70%
	SD		7.76%			5/2014	Transmission Facility Adjustment (TFA)	N/A
	SD		7.76%			6/2011	Environmental Improvement Adjustment Tariff	N/A
	FERC	10.8%	9.10%	43%/57%		2/2009	FERC Transmission Tariff	N/A
Wyoming Electric	WY	9.9%	7.98%	46%/54%	$376.8	10/2014	PCA, Energy Efficiency Cost Recovery/DSM, Rate Base Recovery on Acquisition Adjustment	N/A
	FERC	10.6%	8.51%	46%/54%	$31.5	5/2014	FERC Transmission Tariff	N/A
Colorado Electric	CO	9.37%	7.43%	47.6%/52.4%	$539.6	1/2017	ECA, TCA, PCCA, Energy Efficiency Cost Recovery/DSM, Renewable Energy Standard Adjustment	90%
	CO	9.37%	6.02%	67.3%/32.7%	$57.9	1/2017	Clean Air Clean Jobs Act Adjustment Rider	N/A

The regulatory provisions for recovering the costs to supply electricity vary by state. In all states, subject to thresholds noted below, we have cost adjustment mechanisms for our Electric Utilities that allow us to pass the prudently-incurred cost of fuel and purchased power through to customers. These mechanisms allow the utility operating in that state to collect, or refund, the difference between the cost of commodities and certain services embedded in our base rates and the actual cost of the commodities and certain services without filing a general rate review. Some states in which our utilities operate also allow the utility operating in that state to automatically adjust rates periodically for the cost of new transmission or environmental improvements and, in some instances, the utility has the opportunity to earn its authorized return on new capital investment immediately.

The significant mechanisms we have in place include the following by utility and state:

South Dakota Electric has:

- An annual adjustment clause which provides for the direct recovery of increased fuel and purchased power cost incurred to serve South Dakota customers. Additionally, the ECA contains an off-system sales sharing mechanism in which South Dakota customers will receive a credit equal to 100% of off-system power marketing operating income from the first $2 million of power marketing margin from short-term sales and a credit equal to 70% of power marketing margins from short-term sales in excess of the first $2 million. South Dakota Electric retains the additional 30%. The ECA methodology allows us to directly assign renewable resources and firm purchases to the customer load. In Wyoming, a similar fuel and purchased power cost adjustment is also in place.

- An approved annual Environmental Improvement Adjustment (EIA) tariff which recovers costs associated with generation plant environmental improvements. The EIA and TFA were suspended for a six-year period effective July

1, 2017. See Note 13 in the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

- An approved FERC Transmission Tariff based on a formulaic approach that determines the revenue component of South Dakota Electric's open access transmission tariff.

In Wyoming, Wyoming Electric has:

- An annual cost adjustment mechanism that allows us to pass the prudently-incurred costs of fuel and purchased power through to electric customers. The annual cost adjustment allows for recovery of 85% of coal and coal-related cost per kWh variances from base, and recovery of 95% of purchased power, transmission, and natural gas cost per kWh variances from base.

- An approved FERC Transmission Tariff that determines the revenue component of Wyoming Electric's open access transmission tariff.

In Colorado, Colorado Electric has:

- A quarterly ECA rider that allows us to recover forecasted increases or decreases in purchased energy and fuel costs, including the recovery for amounts payable to others for the transmission of the utility's electricity over transmission facilities owned by others, symmetrical interest, and the sharing of off-system sales margins, less certain operating costs (customer receives 90%). The ECA provides for not only direct recovery, but also for the issuance of credits for decreases in purchased energy, fuel costs and eligible energy resources.

- Colorado allows an annual TCA rider that includes nine months of actual transmission investment and three months of forecasted investment, with an annual true-up mechanism.

- The Clean Air Clean Jobs Act Adjustment rider rate collects the authorized revenue requirement for the 40 MW combustion turbine placed in service on December 31, 2016 with rates effective January 1, 2017.

- The Renewable Energy Standard Adjustment rider is specifically designed for meeting the requirements of Colorado's renewable energy standard and most recently includes cost recovery for the Peak View Wind Project.

See Note 13 in the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for additional information regarding current electric rate activity.

Operating Statistics. The following tables summarize information for our Electric Utilities:

Degree Days	2017		2016		2015	
	Actual	Variance from 30-Year Average [b]	Actual	Variance from 30-Year Average [b]	Actual	Variance from 30-Year Average [b]
Heating Degree Days:						
South Dakota Electric	6,870	(4)%	6,402	(10)%	6,521	(8)%
Wyoming Electric	6,623	(12)%	6,363	(14)%	6,404	(10)%
Colorado Electric	4,693	(16)%	4,658	(16)%	4,846	(12)%
Combined [a]	5,826	(11)%	5,595	(13)%	5,729	(10)%
Cooling Degree Days:						
South Dakota Electric	709	11%	646	(4)%	577	(14)%
Wyoming Electric	429	23%	460	31%	407	16%
Colorado Electric	1,027	14%	1,358	42%	1,270	32%
Combined [a]	798	14%	935	26%	861	16%

(a) The combined heating degree days are calculated based on a weighted average of total customers by state.
(b) 30-Year Average is from NOAA Climate Normals.

	Electric Revenue (in thousands)			Quantities sold (MWh)		
	2017	2016	2015	2017	2016	2015
Residential	$ 210,172	$ 208,725	$ 209,664	1,390,952	1,395,097	1,399,901
Commercial	258,754	258,768	258,539	2,038,495	2,067,486	2,031,556
Industrial	122,958	118,181	112,255	1,598,755	1,515,553	1,399,641
Municipal	18,144	17,821	17,863	160,882	162,383	159,496
Subtotal Retail Revenue - Electric	610,028	603,495	598,321	5,189,084	5,140,519	4,990,594
Contract Wholesale	30,435	17,037	17,537	722,659	246,630	260,893
Off-system/Power Marketing Wholesale	21,111	22,355	29,726	661,263	769,843	1,000,085
Other	43,076	34,394	34,259	—	—	—
Total Revenue and Energy Sold	704,650	677,281	679,843	6,573,006	6,156,992	6,251,572
Other Uses, Losses or Generation, net	—	—	—	468,179	433,400	414,159
Total Revenue and Energy	704,650	677,281	679,843	7,041,185	6,590,392	6,665,731
Less cost of fuel and purchased power	268,405	261,349	269,409			
Gross Margin	$ 436,245	$ 415,932	$ 410,434			

	Electric Revenue (in thousands)			Gross Margin [a] (in thousands)			Quantities Sold (MWh) [b]		
	2017	2016	2015	2017	2016	2015	2017	2016	2015
South Dakota Electric	$ 288,433	$ 267,632	$ 277,864	$ 200,795	$ 192,606	$ 194,524	3,187,392	2,767,315	3,040,703
Wyoming Electric	165,127	157,606	150,156	89,371	85,036	83,537	1,762,117	1,677,421	1,530,628
Colorado Electric	251,090	252,043	251,823	146,079	138,290	132,373	2,091,676	2,145,656	2,094,400
Total Revenue, Gross Margin, and Quantities Sold	$ 704,650	$ 677,281	$ 679,843	$ 436,245	$ 415,932	$ 410,434	7,041,185	6,590,392	6,665,731

(a) Non-GAAP measure
(b) Total MWh includes Other Uses, Losses or Generation, net, which is approximately 6%, 7%, and 8% for South Dakota Electric, Wyoming Electric, and Colorado Electric, respectively.

Quantities Generated and Purchased (MWh)	2017	2016	2015
Coal-fired	2,230,617	2,201,757	2,228,377
Natural Gas and Oil	307,815	343,001	230,320
Wind	239,472	80,582	41,043
Total Generated	2,777,904	2,625,340	2,499,740
Purchased	4,263,281	3,965,052	4,165,991
Total Generated and Purchased	7,041,185	6,590,392	6,665,731

Quantities Generated and Purchased (MWh)	2017	2016	2015
Generated:			
South Dakota Electric	1,581,915	1,585,870	1,618,688
Wyoming Electric	798,024	805,351	739,277
Colorado Electric	397,965	234,119	141,775
Total Generated	2,777,904	2,625,340	2,499,740
Purchased:			
South Dakota Electric	1,605,477	1,181,445	1,422,015
Wyoming Electric	964,093	872,070	791,351
Colorado Electric	1,693,711	1,911,537	1,952,625
Total Purchased	4,263,281	3,965,052	4,165,991
Total Generated and Purchased	7,041,185	6,590,392	6,665,731

Customers at End of Year	2017	2016	2015
Residential	179,911	178,333	176,901
Commercial	29,354	29,086	29,172
Industrial	86	88	87
Other	914	1,001	1,027
Total Electric Customers at End of Year	210,265	208,508	207,187

Customers at End of Year	2017	2016	2015
South Dakota Electric	72,184	71,353	70,733
Wyoming Electric	42,130	41,531	41,422
Colorado Electric	95,951	95,624	95,032
Total Electric Customers at End of Year	210,265	208,508	207,187

Gas Utilities Segment

We conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming subsidiaries. On February 12, 2016, we acquired SourceGas Holdings, LLC, adding four regulated natural gas utilities serving approximately 431,000 customers in Arkansas, Colorado, Nebraska and Wyoming and a 512 mile regulated intrastate natural gas transmission pipeline in Colorado. Our Gas Utilities transport and distribute natural gas through our distribution network to approximately 1,042,000 customers. Additionally, we sell contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates, on an as available basis.

We also provide non-regulated services through Black Hills Energy Services. Black Hills Energy Services has approximately 52,000 retail distribution customers in Nebraska and Wyoming providing unbundled natural gas commodity offerings under the regulatory-approved Choice Gas Program. We also sell, install and service air, heating and water-heating equipment, and provide associated repair service and appliance protection plans under various trade names. Service Guard and CAPP provide appliance repair services to approximately 63,000 and 31,000 residential customers, respectively, through Company technicians and third-party service providers, typically through on-going monthly service agreements. Tech Services serves gas transportation customers throughout our service territory by constructing and maintaining customer-owned gas infrastructure facilities, typically through one-time contracts.

We procure natural gas for our distribution customers from a diverse mix of producers, processors and marketers and generally use hedging, physical fixed-price purchases and market-based price purchases to achieve dollar-cost averaging within our natural gas portfolio. The majority of our procured natural gas is transported in interstate pipelines under firm transportation service agreements with Colorado Interstate Gas Company, Enable Gas Transmission, Tallgrass Interstate Gas Transmission, Natural Gas Pipeline Company of America, Northern Natural Gas, Panhandle Eastern Pipeline Company, Southern Star Central Gas Pipeline, Black Hills Shoshone Pipeline, TransColorado Gas Transmission, WBI Energy Transmission, Rocky Mountain Natural Gas, Ozark Gas Transmission, Liberty Utilities, Texas Eastern Transmission Pipeline, WestGas InterState Pipeline, Public Service Company of Colorado and Red Cedar Gas Gathering.

In addition to company-owned storage assets in Wyoming, Colorado and Arkansas, we also contract with many of the third-party transportation providers noted above for natural gas storage service to provide gas supply during the winter heating season and to meet peak day customer demand for natural gas.

The following table summarizes certain information regarding our regulated underground gas storage facilities as of December 31, 2017:

State	Working Capacity (Mcf)	Cushion Gas (Mcf) [(a)]	Total Capacity (Mcf)	Maximum Daily Withdrawal Capability (Mcfd)
Arkansas	8,442,700	12,950,000	21,392,700	196,000
Colorado	2,360,895	6,165,315	8,526,210	30,000
Wyoming	5,733,900	17,145,600	22,879,500	32,950
Total	16,537,495	36,260,915	52,798,410	258,950

(a) Cushion gas represents the volume of gas that must be retained in a facility to maintain reservoir pressure.

The following tables summarize certain operating information for our Gas Utilities.

System Infrastructure (in line miles) as of December 31, 2017	Intrastate Gas Transmission Pipelines	Gas Distribution Mains	Gas Distribution Service Lines
Arkansas	926	4,654	919
Colorado	683	6,569	2,399
Nebraska	1,256	8,467	3,219
Iowa	163	2,777	2,653
Kansas	325	2,855	1,337
Wyoming	1,303	3,396	1,210
Total	4,656	28,718	11,737

Degree Days	2017		2016		2015	
	Actual	Variance From 30-Year Average [d]	Actual	Variance From 30-Year Average [d]	Actual	Variance From 30-Year Average [d]
Heating Degree Days:						
Arkansas [a]	3,295	(19)%	2,397	(41)%	—	—%
Colorado	5,728	(14)%	5,762	(13)%	5,527	(12)%
Nebraska	5,554	(10)%	5,457	(12)%	5,350	(12)%
Iowa	6,149	(9)%	5,997	(11)%	6,629	(2)%
Kansas [a]	4,452	(9)%	4,307	(12)%	4,432	(9)%
Wyoming	7,123	(5)%	6,750	(10)%	6,404	(10)%
Combined [b] [c]	5,862	(10)%	5,823	(11)%	5,890	(8)%

(a) Kansas and Arkansas have weather normalization mechanisms which mitigate the weather impact on gross margins.
(b) The combined heating degree days are calculated based on a weighted average of total customers by state excluding Kansas Gas due to its weather normalization mechanism. Arkansas Gas Distribution is partially excluded based on the weather normalization mechanism in effect from November through April.
(c) To conform to the current year comparisons to normal, the 2016 utility variances compared to normal, as well as the 2016 combined variance compared to normal have been updated.
(d) 30-Year Average is from NOAA climate normals.

Seasonal Variations of Business. Our Gas Utilities are seasonal businesses and weather patterns may impact their operating performance. Demand for natural gas is sensitive to seasonal heating and industrial load requirements, as well as market price. In particular, demand is often greater in the winter months for heating. Natural gas is used primarily for residential and commercial heating, so the demand for this product depends heavily upon weather throughout our service territories, and as a result, a significant amount of natural gas revenue is normally recognized in the heating season consisting of the first and fourth quarters. Demand for natural gas can also be impacted by summer weather patterns that are cooler than normal and provide higher than normal precipitation; both of which can reduce natural gas demand for irrigation.

Competition. We generally have limited competition for the retail distribution of natural gas in our service areas. Various restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate. These initiatives would be aimed at increasing competition. To date, these initiatives have not had a material impact on our utilities. Although we face competition from independent marketers for the sale of natural gas to our industrial and commercial customers, in instances where independent marketers displace us as the seller of natural gas, we still collect a distribution charge for transporting the gas through our distribution network.

Rates and Regulation. Our Gas Utilities are subject to the jurisdiction of the public utilities commissions in the states where they operate. The commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. The public utility commissions determine the rates we are allowed to charge for our utility services. Rate decisions are influenced by many factors, including the cost of providing service, capital expenditures, the prudence of costs we incur, views concerning appropriate rates of return, the rates of other utilities, general economic conditions and the political environment. Certain commissions also have jurisdiction over the issuance of debt or securities, and the creation of liens on property located in their states to secure bonds or other securities.

Our Gas Utilities are authorized to use natural gas cost recovery mechanisms that allow them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure that they recover all the costs prudently incurred in purchasing gas for their customers. In addition to natural gas recovery mechanisms, we have other cost recovery mechanisms, such as regulatory riders, which vary by utility but allow us to recover certain costs, such as those related to energy efficiency plans and system safety and integrity investments. The following table provides regulatory information for each of our natural gas utilities:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Additional Tariffed Mechanisms
Gas Utilities:							
Arkansas Gas [(a)]	AR	9.4%	6.47% [(b)]	52%/48%	$299.4 [(c)]	2/2016	GCA, Main Replacement Program, At-Risk Meter Relocation Program, Legislative/Regulatory Mandate and Relocations Rider, Energy Efficiency, Weather Normalization Adjustment, Billing Determinant Adjustment
Colorado Gas	CO	9.6%	8.41%	50%/50%	$64.0	12/2012	GCA, Energy Efficiency Cost Recovery/DSM
Colorado Gas Dist.[(a)]	CO	10.0%	8.02%	49.52%/ 50.48%	$127.1	12/2010	GCA, DSM
RMNG [(a)]	CO	10.6%	7.93%	49.23%/ 50.77%	$90.5	3/2014	System Safety Integrity Rider, Liquids/Off-system/Market Center Services Revenue Sharing
Iowa Gas	IA	Global Settlement	Global Settlement	Global Settlement	$109.2	2/2011	GCA, Energy Efficiency Cost Recovery/DSM/Capital Infrastructure Automatic Adjustment Mechanism, Gas Supply Optimization revenue sharing
Kansas Gas	KS	Global Settlement	Global Settlement	Global Settlement	$127.4	1/2015	GCA, Weather Normalization Tariff, Gas System Reliability Surcharge, Ad Valorem Tax Surcharge, Cost of Bad Debt Collected through GCA, Pension Levelized Adjustment
Nebraska Gas	NE	10.1%	9.11%	48%/52%	$161.3	9/2010	GCA, Cost of Bad Debt Collected through GCA, Infrastructure System Replacement Cost Recovery Surcharge
Nebraska Gas Dist. [(a)]	NE	9.6%	7.67%	48.84%/ 51.16%	$87.6/$69.8 [(d)]	6/2012	Choice Gas Program, System Safety and Integrity Rider, Bad Debt expense recovered through Choice supplier fee
Wyoming Gas	WY	9.9%	7.98%	46%/54%	$59.6	10/2014	GCA, Energy Efficiency Cost Recovery/DSM, Rate Base Recovery on Acquisition Adjustment
Wyoming Gas Dist. [(a)]	WY	9.92%	7.98%	49.66%/ 50.34%	$100.5	1/2011	Choice Gas Program, Purchased GCA, Usage Per Customer Adjustment

(a) Acquired through SourceGas
(b) Arkansas return on rate base adjusted to remove current liabilities from rate case capital structure for comparison with other subsidiaries.
(c) Arkansas rate base is adjusted to include current liabilities for comparison with other subsidiaries.
(d) Total Nebraska rate base of $87.6 million includes amounts allocated to serve non-jurisdictional and agricultural customers. Jurisdictional Nebraska rate base of $69.8 million excludes those amounts allocated to serve non-jurisdictional and agricultural customers and is used for calculation of jurisdictional base rates.

All of our Gas Utilities, except where ChoiceGas is the only option, have GCAs that allow us to pass the prudently-incurred cost of gas and certain services through to the customer between rate reviews. Some of the mechanisms we have in place include the following:

Gas Utility Jurisdiction	Cost Recovery Mechanisms							
	DSM/Energy Efficiency	Integrity Additions	Bad Debt	Weather Normal	Pension Recovery	Gas Cost	Billing Determinant Adjustment	Revenue Decoupling
Arkansas Gas	☑	☑		☑		☑	☑	
Colorado Gas	☑					☑		
Colorado Gas Dist.	☑					☑		
Rocky Mountain Natural Gas	N/A	☑	N/A	N/A	N/A	N/A	N/A	N/A
Iowa Gas	☑	☑				☑		
Kansas Gas		☑	☑	☑	☑	☑		
Nebraska Gas		☑	☑			☑		
Nebraska Gas Dist.		☑	☑			☑		
Wyoming Gas [(a)]	☑					☑		
Wyoming Gas Dist.						☑		☑

(a) This is only applicable to Cheyenne Light and does not apply to our other Wyoming gas utilities.

See Note 13 in the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for information regarding current natural gas rate activity.

Operating Statistics

2016 includes results from the acquired SourceGas utilities starting February 12, 2016.

	Revenue (in thousands)			Gross Margin [(a)] (in thousands)		
	2017	2016	2015	2017	2016	2015
Residential	$ 499,852	$ 433,106	$ 342,145	$ 255,626	$ 228,512	$ 155,759
Commercial	197,054	162,547	117,574	78,249	67,375	38,492
Industrial	24,454	21,245	22,398	6,226	5,601	4,303
Other	8,647	12,694	8,065	8,647	12,694	7,995
Total Distribution	730,007	629,592	490,182	348,748	314,182	206,549
Transportation and Transmission	135,824	139,490	29,816	135,824	139,282	29,816
Total Regulated	865,831	769,082	519,998	484,572	453,464	236,365
Non-regulated Services	81,799	69,261	31,302	53,455	32,714	15,290
Total Revenue & Gross Margin	$ 947,630	$ 838,343	$ 551,300	$ 538,027	$ 486,178	$ 251,655

	Revenue (in thousands)			Gross Margin [(a)] (in thousands)		
	2017	2016	2015	2017	2016	2015
Arkansas	$ 153,691	$ 106,958	$ —	$ 94,007	$ 69,840	$ —
Colorado	180,852	153,003	73,854	100,718	86,016	25,387
Nebraska	252,631	244,992	170,972	154,259	146,831	82,877

Iowa	143,446	130,776	147,952	66,619	64,170	63,496
Kansas	105,576	100,670	114,362	53,841	54,247	57,888
Wyoming	111,434	101,944	44,160	68,583	65,074	22,007
Total Revenue & Gross Margin	$ 947,630	$ 838,343	$ 551,300	$ 538,027	$ 486,178	$ 251,655

(a) Non-GAAP measure

Gas Utilities Quantities Sold & Transported (Dth)	Quantities 2017	2016	2015
Residential	54,645,598	49,390,451	35,649,700
Commercial	27,315,871	24,037,861	15,765,242
Industrial	5,855,053	5,737,430	5,208,455
Other	—	—	14,902
Total Distribution Quantities Sold	87,816,522	79,165,742	56,638,299
Transportation and Transmission	141,600,080	126,927,565	77,393,775
Total Quantities Sold & Transported	229,416,602	206,093,307	134,032,074

Gas Utilities Quantities Sold & Transported (Dth)	Quantities 2017	2016	2015
Arkansas	26,491,537	19,177,438	—
Colorado	28,436,744	23,656,891	9,288,030
Nebraska	73,890,509	67,796,021	43,992,986
Iowa	37,013,645	35,383,990	35,490,228
Kansas	28,251,947	26,463,314	28,086,737
Wyoming	35,332,220	33,615,653	17,174,093
Total Quantities Sold & Transported	229,416,602	206,093,307	134,032,074

Customers at End of Year	2017	2016	2015
Residential	806,744	800,980	533,413
Commercial	86,461	84,049	50,175
Industrial	2,214	2,050	1,859
Transportation/Other	146,839	143,673	5,962
Total Customers at End of Year	1,042,258	1,030,752	591,409

Customers at End of Year	2017	2016	2015
Arkansas	169,303	166,512	—
Colorado	181,876	177,394	78,434
Nebraska	290,264	289,653	201,261
Iowa	157,444	156,014	155,196
Kansas	114,082	112,957	112,364
Wyoming	129,289	128,222	44,154
Total Customers at End of Year	1,042,258	1,030,752	591,409

Utility Regulation Characteristics

State Regulations

Certain states where we conduct electric utility operations have adopted renewable energy portfolio standards that require or encourage our Electric Utilities to source, by a certain future date, a minimum percentage of the electricity delivered to customers from renewable energy generation facilities. As of December 31, 2017, we were subject to the following renewable energy portfolio standards or objectives:

- Colorado. Colorado adopted a renewable energy standard that has two components: (i) electric resource standards and (ii) a 2% maximum annual retail rate impact for compliance with the electric resource standards. The electric resource standards require our Colorado Electric subsidiary to generate, or cause to be generated, electricity from renewable energy sources equaling: (i) 20% of retail sales from 2015 to 2019; and (ii) 30% of retail sales by 2020. Of these amounts, 3% must be generated from distributed generation sources with one-half of these resources being located at customer facilities. The net annual incremental retail rate impact from these renewable resource acquisitions (as compared to non-renewable resources) is limited to 2%. The standard encourages the CPUC to consider earlier and timely cost recovery for utility investment in renewable resources, including the use of a forward rider mechanism. We are currently in compliance with these standards.

  Colorado Electric received a settlement agreement of its electric resource plan filed June 3, 2016, to meet requirements under the Colorado Renewable Energy Standard. The settlement, effective February 6, 2017, includes the addition of 60 megawatts of renewable energy to be in service by 2019 and provides for additional small solar and community solar gardens as part of the compliance plan. In the second quarter of 2017, Colorado Electric issued a request for proposals to construct new generation and presented the results to the CPUC on February 9, 2018. We expect a final decision from the CPUC in the second quarter of 2018 approving, conditioning, modifying or rejecting Colorado Electric’s recommended portfolio.

  On November 7, 2016, Colorado Electric took ownership of Peak View, a $109 million, 60 MW wind project located near Colorado Electric's Busch Ranch Wind Farm. Peak View achieved commercial operation on November 7, 2016 and was purchased via progress payments throughout 2016 under a commission approved third-party build transfer and settlement agreement. This renewable energy project was originally submitted in response to Colorado Electric’s all-source generation request on May 5, 2014. The Commission’s settlement agreement provides for recovery of the costs of the project through Colorado Electric’s Electric Cost Adjustments and Renewable Energy Standard Surcharge for 10 years and recovery through the Transmission Cost Adjustment, after which Colorado Electric can propose base rate recovery. Colorado Electric will be required to make an annual comparison of the cost of the renewable energy generated by the facility against the bid cost of a PPA from the same facility.

- Montana. In 2005, Montana established a renewable portfolio standard that requires public utilities to obtain a percentage of their retail electricity sales from eligible renewable resources. In March 2013, South Dakota Electric filed a petition with the MTPSC requesting a waiver of the renewable portfolio standards primarily due to exceeding the applicable “cost cap” included in the standards. In March 2013, the Montana Legislature adopted legislation that had the effect of excluding South Dakota Electric from all renewable portfolio standard requirements under State Senate Bill 164, primarily due to the very low number of customers we have in Montana and the relatively high cost of meeting the renewable requirements.

- South Dakota. South Dakota has adopted a renewable portfolio objective that encourages, but does not mandate utilities to generate, or cause to be generated, at least 10% of their retail electricity supply from renewable energy sources by 2015.

- Wyoming. Wyoming currently has no renewable energy portfolio standard.

Absent a specific renewable energy mandate in the territories we serve, our current strategy is to prudently incorporate renewable energy into our resource supply, seeking to minimize associated rate increases for our utility customers. Mandatory portfolio standards have increased and would likely continue to increase the power supply costs of our Electric Utility operations. Although we will seek to recover these higher costs in rates, we can provide no assurance that we will be able to secure full recovery of the costs we pay to be in compliance with standards or objectives. We cannot at this time reasonably forecast the potential costs associated with any new renewable energy standards that have been or may be proposed at the federal or state level.

Federal Regulation

Energy Policy Act. Black Hills Corporation is a holding company whose assets consist primarily of investments in our subsidiaries, including subsidiaries that are public utilities and holding companies regulated by FERC under the Federal Power Act and PUHCA 2005.

Federal Power Act. The Federal Power Act gives FERC exclusive rate-making jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Pursuant to the Federal Power Act, all public utilities subject to FERC's jurisdiction must maintain tariffs and rate schedules on file with FERC that govern the rates, terms and conditions for the provision of FERC-jurisdictional wholesale power and transmission services. Public utilities are also subject to accounting, record-keeping and reporting requirements administered by FERC. FERC also places certain limitations on transactions between public utilities and their affiliates. Our public Electric Utility subsidiaries provide FERC-jurisdictional services subject to FERC's oversight.

Our Electric Utilities, Black Hills Colorado IPP and Black Hills Wyoming are authorized by FERC to make wholesale sales of electric capacity and energy at market-based rates under tariffs on file with FERC. As a condition of their market-based rate authority, each files Electric Quarterly Reports with FERC. South Dakota Electric owns and operates FERC-jurisdictional interstate transmission facilities and provides open access transmission service under tariffs on file with FERC. Our Electric Utilities are subject to routine audit by FERC with respect to their compliance with FERC's regulations.

The Federal Power Act authorizes FERC to certify and oversee a national electric reliability organization with authority to promulgate and enforce mandatory reliability standards applicable to all users, owners and operators of the bulk-power system. FERC has certified NERC as the electric reliability organization. NERC has promulgated mandatory reliability standards and NERC, in conjunction with regional reliability organizations that operate under FERC's and NERC's authority and oversight, enforces those mandatory reliability standards.

PUHCA 2005. PUHCA 2005 gives FERC authority with respect to the books and records of a utility holding company. As a utility holding company with centralized service company subsidiaries, BHSC and Black Hills Utility Holdings, we are subject to FERC's authority under PUHCA 2005.

Power Generation Segment

Our Power Generation segment, which operates through Black Hills Electric Generation and its subsidiaries, acquires, develops and operates our non-regulated power plants. As of December 31, 2017, we held varying interests in independent power plants operating in Wyoming and Colorado with a total net ownership of approximately 269 MW.

We produce electric power from our generating plants and sell the electric capacity and energy, primarily to affiliates under a combination of mid- to long-term contracts, which mitigates the impact of a potential downturn in future power prices. We currently sell a substantial majority of our non-regulated generating capacity under contracts having terms greater than one year.

As of December 31, 2017, the power plant ownership interests held by our Power Generation segment included:

Power Plants	Fuel Type	Location	Ownership Interest	Owned Capacity (MW)	In Service Date
Wygen I	Coal	Gillette, Wyoming	76.5%	68.9	2003
Pueblo Airport Generation [(a)]	Gas	Pueblo, Colorado	50.1%	200.0	2012
				268.9	

(a) Black Hills Colorado IPP owns and operates this facility. This facility provides capacity and energy to Colorado Electric under a 20-year PPA with Colorado Electric. This PPA is accounted for as a capital lease on the accompanying Consolidated Financial Statements.

Black Hills Wyoming - Wygen I. The Wygen I generation facility is a mine-mouth, coal-fired power plant with a total capacity of 90 MW located at our Gillette, Wyoming energy complex. We own 76.5% of the plant and MEAN owns the remaining 23.5%. We sell 60 MW of unit-contingent capacity and energy from this plant to Wyoming Electric under a PPA that expires on December 31, 2022. The PPA includes an option for Wyoming Electric to purchase Black Hills Wyoming's ownership interest in the Wygen I facility through 2019. The purchase price related to the option is $2.6 million per MW (65 MWs),

adjusted for all depreciated capital additions since 2009, and reduced by depreciation (approximately $5 million per year) over a 35-year life beginning January 1, 2009. The net book value of Wygen I at December 31, 2017 was $69 million and if Wyoming Electric had exercised the purchase option at year-end 2017, the estimated purchase price would have been approximately $133 million. We sell excess power from our generating capacity into the wholesale power markets when it is available and economical to do so.

Black Hills Colorado IPP - Pueblo Airport Generation. The Pueblo Airport Generating Station consists of two 100 MW combined-cycle gas-fired power generation plants located at a site shared with Colorado Electric. The plants commenced operation on January 1, 2012 and the assets are accounted for as a capital lease under a 20-year PPA with Colorado Electric, which expires on December 31, 2031. Under the PPA with Colorado Electric, any excess capacity and energy shall be for the benefit of Colorado Electric.

Sale of Noncontrolling Interest in Subsidiary

On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million to a third party buyer. FERC approval of the sale was received on March 29, 2016. Black Hills Electric Generation is the operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric. Proceeds from the sale were used to pay down short-term debt and for other general corporate purposes. The operating results for Black Hills Colorado IPP remain consolidated with Black Hills Electric Generation, as Black Hills Colorado IPP has been determined to be a variable interest entity (VIE) in which the Company has a variable interest.

The following table summarizes MWh for our Power Generation segment:

Quantities Sold, Generated and Purchased (MWh) [a]	2017	2016	2015
Sold			
Black Hills Colorado IPP [b]	943,618	1,223,949	1,133,190
Black Hills Wyoming [c]	645,810	644,564	663,052
Total Sold	1,589,428	1,868,513	1,796,242
Generated			
Black Hills Colorado IPP [b]	943,618	1,223,949	1,133,190
Black Hills Wyoming	577,124	543,546	561,930
Total Generated	1,520,742	1,767,495	1,695,120
Purchased			
Black Hills Wyoming [b]	69,377	85,993	68,744
Total Purchased	69,377	85,993	68,744

(a) Company use and losses are not included in the quantities sold, generated and purchased.
(b) The decrease in 2017 is driven by the joint dispatch agreement Colorado Electric joined in 2017. See details of this agreement above in the Electric Utilities segment.
(c) Under the 20-year economy energy PPA with the City of Gillette, effective September 2014, Black Hills Wyoming purchases energy on behalf of the City of Gillette and sells that energy to the City of Gillette.

Operating Agreements. Our Power Generation segment has the following material operating agreements:

- Economy Energy PPA and other ancillary agreements
  - Black Hills Wyoming sold its CTII 40 MW natural gas-fired generating unit to the City of Gillette, Wyoming on September 3, 2014. Under the terms of the sale, Black Hills Wyoming entered into ancillary agreements to operate CTII, and provide use of shared facilities including a ground lease and dispatch generation services. In addition, the agreement includes a 20-year economy energy PPA that contains a sharing arrangement in which the parties share the savings of wholesale power purchases made when market power prices are less than the cost of operating the generating unit.

- Operating and Maintenance Services Agreement
    - In conjunction with the sale of the noncontrolling interest on April 14, 2016, an operating and maintenance services agreement was entered into between Black Hills Electric Generation and Black Hills Colorado IPP. This agreement sets forth the obligations and responsibilities of Black Hills Electric Generation as the operator of the generating facility owned by Black Hills Colorado IPP. This agreement is in effect from the date of the noncontrolling interest purchase and remains effective as long as the operator or one of its affiliates is responsible for managing the generating facilities in accordance with the noncontrolling interest agreement, or until termination by owner or operator.
- Shared Services Agreements
    - South Dakota Electric, Wyoming Electric and Black Hills Wyoming are parties to a shared facilities agreement, whereby each entity charges for the use of assets by the affiliate entity.
    - Black Hills Colorado IPP and Colorado Electric are parties to a facility fee agreement, whereby Colorado Electric charges Black Hills Colorado IPP for the use of Colorado Electric assets.
    - Black Hills Colorado IPP, Wyoming Electric and South Dakota Electric are parties to a Spare Turbine Use Agreement, whereby Black Hills Colorado IPP charges South Dakota Electric and Wyoming Electric a monthly fee for the availability of a spare turbine to support the operation of Cheyenne Prairie Generating Station.
    - Black Hills Colorado IPP and Black Hills Wyoming receive certain staffing and management services from BHSC.
- Jointly Owned Facilities
    - Black Hills Wyoming and MEAN are parties to a shared joint ownership agreement, whereby Black Hills Wyoming charges MEAN for administrative services, plant operations and maintenance on their share of the Wygen I generating facility over the life of the plant.

Competition. The independent power industry consists of many strong and capable competitors, some of which may have more extensive operations or greater financial resources than we possess.

With respect to the merchant power sector, FERC has taken steps to increase access to the national transmission grid by utility and non-utility purchasers and sellers of electricity and foster competition within the wholesale electricity markets. Our Power Generation business could face greater competition if utilities are permitted to robustly invest in power generation assets. Conversely, state regulatory rules requiring utilities to competitively bid generation resources may provide opportunity for independent power producers in some regions.

The Energy Policy Act of 1992. The passage of the Energy Policy Act of 1992 encouraged independent power production by providing certain exemptions from regulation for EWGs. EWGs are exclusively in the business of owning or operating, or both owning and operating, eligible power facilities and selling electric energy at wholesale. EWGs are subject to FERC regulation, including rate regulation. We own two EWGs: Wygen I and 200 MW (two 100 MW combined-cycle gas-fired units) at the Pueblo Airport Generating Station. Our EWGs were granted market-based rate authority, which allows FERC to waive certain accounting, record-keeping and reporting requirements imposed on public utilities with cost-based rates.

Mining Segment

Our Mining segment operates through our WRDC subsidiary. We surface mine, process and sell primarily low-sulfur sub-bituminous coal at our mine near Gillette, Wyoming. The WRDC coal mine, which we acquired in 1956 from Homestake Gold Mining Company, is located in the Powder River Basin. The Powder River Basin contains one of the largest coal reserves in the United States. We produced approximately 4.2 million tons of coal in 2017.

During our surface mining operations, we strip and store the topsoil. We then remove the overburden (earth and rock covering the coal) with heavy equipment. Removal of the overburden typically requires drilling and blasting. Once the coal is exposed, we drill, fracture and systematically remove it, using front-end loaders and conveyors to transport the coal to the mine-mouth generating facilities. We reclaim disturbed areas as part of our normal mining activities by back-filling the pit with overburden removed during the mining process. Once we have replaced the overburden and topsoil, we re-establish vegetation and plant life in accordance with our approved post-mining topography plan.

In a basin characterized by thick coal seams, our overburden ratio, a comparison of the cubic yards of dirt removed to a ton of coal uncovered, has in recent years trended upwards. The overburden ratio at December 31, 2017 was 2.16, which increased from the prior year as we continued mining in areas with higher overburden. We expect our stripping ratio to be approximately 2.15 by the end of 2018 as we mine in areas with comparable overburden.

Mining rights to the coal are based on four federal leases and one state lease. The federal leases expire between April 30, 2019 and September 30, 2025 and the state lease expires on August 1, 2023. The duration of the leases varies; however, the lease terms generally are extended to the exhaustion of economically recoverable reserves, as long as active mining continues. We pay federal and state royalties of 12.5% of the selling price of all coal. As of December 31, 2017, we estimated our recoverable coal reserves to be approximately 195 million tons, based on a life-of-mine engineering study utilizing currently available drilling data and geological information prepared by internal engineering studies. The recoverable coal reserve life is equal to approximately 47 years at the current production levels. Our recoverable coal reserve estimates are periodically updated to reflect past coal production and other geological and mining data. Changes in mining methods or the utilization of new technologies may increase or decrease the recovery basis for a coal seam. Our recoverable coal reserves include reserves that can be economically and legally extracted at the time of their determination. We use various assumptions in preparing our estimate of recoverable coal reserves. See Risk Factors under Mining for further details.

Substantially all of our coal production is currently sold under contracts to:

- South Dakota Electric for use at the 90 MW Neil Simpson II plant. This contract is for the life of the plant;
- Wyoming Electric for use at the 95 MW Wygen II plant. This contract is for the life of the plant;
- The 362 MW Wyodak power plant owned 80% by PacifiCorp and 20% by South Dakota Electric. PacifiCorp is obligated to purchase a minimum of 1.5 million tons of coal each year of the contract term, subject to adjustments for planned outages. South Dakota Electric is also obligated to purchase a minimum of 0.375 million tons of coal per year for its 20% share of the power plant. This contract expires December 31, 2022;
- The 110 MW Wygen III power plant owned 52% by South Dakota Electric, 25% by MDU and 23% by the City of Gillette to which we sell approximately 600,000 tons of coal each year. This contract expires June 1, 2060;
- The 90 MW Wygen I power plant owned 76.5% by Black Hills Wyoming and 23.5% by MEAN to which we sell approximately 500,000 tons of coal each year. This contract expires June 30, 2038; and
- Certain regional industrial customers served by truck to which we sell a total of approximately 150,000 tons of coal each year. These contracts have terms of one to five years.

Our Mining segment sells coal to South Dakota Electric and Wyoming Electric for all of their requirements under cost-based agreements that regulate earnings from these affiliate coal sales to a specified return on our coal mine's cost-depreciated investment base. The return calculated annually is 400 basis points above A-rated utility bonds applied to our Mining investment base. South Dakota Electric made a commitment to the SDPUC, the WPSC and the City of Gillette that coal for South Dakota Electric's operating plants would be furnished and priced as provided by that agreement for the life of the Neil Simpson II plant and through June 1, 2060, for Wygen III. The agreement with Wyoming Electric provides coal for the life of the Wygen II plant.

The price of unprocessed coal sold to PacifiCorp for the Wyodak plant is determined by the coal supply agreement described above. The agreement includes a price adjustment in 2019. The price adjustment essentially allows us to retain the full economic advantage of the mine's location adjacent to the plant. The price adjustment is based on the market price of coal plus considerations for the avoided costs of rail transportation and a coal unloading facility, which PacifiCorp would have to incur if it purchased coal from another mine. In addition, the agreement also provides for the monthly escalation of coal price based on an escalation factor.

WRDC supplies coal to Black Hills Wyoming for the Wygen I generating facility for requirements under an agreement using a base price that includes price escalators and quality adjustments through June 30, 2038 and includes actual cost per ton plus a margin equal to the yield for Moody's A-Rated 10-Year Corporate Bond Index plus 400 basis points with the base price being adjusted on a 5-year interval. The agreement stipulates that WRDC will supply coal to the 90 MW Wygen I plant through June 30, 2038.

Competition. Our primary strategy is to sell the majority of our coal production to on-site, mine-mouth generation facilities under long-term supply contracts. Historically, off-site sales have been to consumers within a close proximity to the mine. Rail transport market opportunities for WRDC coal are limited due to the lower heating value (Btu) of the coal, combined with the fact that the WRDC coal mine is served by only one railroad, resulting in less competitive transportation rates. Management continues to explore the limited market opportunities for our product through truck transport.

Additionally, coal competes with other energy sources, such as natural gas, wind, solar and hydropower. Costs and other factors relating to these alternative fuels, such as safety, environmental considerations and availability affect the overall demand for coal as a fuel.

Environmental Matters. We are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations; and state hazard communication standards. See Environmental Matters section for further information.

Mine Reclamation. Reclamation is required during production and after mining has been completed. Under applicable law, we must submit applications to, and receive approval from, the WDEQ for any mining and reclamation plan that provides for orderly mining, reclamation and restoration of the WRDC mine. We have approved mining permits and are in compliance with other permitting programs administered by various regulatory agencies. The WRDC coal mine is permitted to operate under a five-year mining permit issued by the State of Wyoming. In 2016, that five-year permit was re-issued. Based on extensive reclamation studies, we have accrued approximately $12 million for reclamation costs as of December 31, 2017. Mining regulatory requirements continue to increase, which impose additional cost on the mining process.

Environmental Matters

At Black Hills, we deliver energy to our customers and communities guided by our commitment to environmental stewardship; to sustain environmental compliance which results in healthier communities.

South Dakota and Wyoming Power Generation. Based on current regulations, technology and plans, the following table contains our current estimates of capital expenditures expected to be incurred over the next three years to comply with current environmental laws and regulations as described below, including regulations that cover water, air, soil and other pollutants, but excluding plant closures and the cost of new generation. The ultimate cost could be significantly different from the amounts estimated.

Environmental Expenditure Estimates	Total (in thousands)
2018	$ 3,086
2019	1,674
2020	611
Total	$ 5,371

Methane Rules (Greenhouse Gas Emissions). The EPA and the State of Colorado have implemented strict regulatory requirements on fugitive methane emissions associated with oil and natural gas exploration and production operations and from natural gas gathering and transmission systems. Additionally, the BLM issued a new rule referred to as the Methane Rule (aka Venting and Flaring rule) with the intent to capture methane leaks and lost royalties from companies that operate on federal land.

The rule has been postponed for one year by the BLM, but continues to be legally contested. While this risk is substantially reduced through the divestiture of BHEP, it continues to impact our remaining natural gas gathering and transmission operations. It is anticipated that regulatory control in this area may continue to expand, affecting a larger portion of Black Hills' natural gas operations, including storage and distribution. Presently, we have seven compressor stations in our natural gas transmission operations affected by the rule (one in Arkansas, three in Colorado, and three in Wyoming).

Our operations are currently in compliance with both EPA and BLM rules. Although the BLM rule has been postponed, non- compliance would expose us to both enforcement action and civil suits. We will continue to monitor the litigation until the BLM's rule status is clarified through the resolution of legal challenges. Additionally, we are developing a corporate-wide methane control strategy to address GHG emissions from our natural gas operations.

Water Issues. Our facilities are subject to a variety of state and federal regulations governing existing and potential water/ wastewater discharges and protection of surface waters from oil pollution. Generally, such regulations are promulgated under the Clean Water Act and govern overall water/wastewater discharges through EPA's surface water discharge and storm water permits. All of our facilities that are required to have such permits have those permits in place and are in compliance with discharge limitations and plan implementation requirements. The EPA proposed effluent limitation guidelines and standards on June 7, 2013 and published the final rule on November 3, 2015. This rule will have an impact on the Wyodak Plant. The terms of this new regulation impact the next permit renewal, which will be in 2020. Additionally, the EPA regulates surface water oil pollution through its oil pollution prevention regulations. All of our facilities subject to these regulations have compliant prevention plans in place.

Short-term Emission Limits. The EPA and State Air Quality Programs implemented short-term emission limits for coal and natural gas-fired generating units during normal and start-up operating scenarios for Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_x) and Opacity. The limits pertain to emissions during start-up periods and upset conditions such as mechanical malfunctions. State and federal regulatory agencies typically excuse short-term emissions exceedances if they are reported and corrected immediately or if it occurs during start-up.

We proactively manage this requirement through maintenance efforts and installing additional pollution control systems to control SO_2 emission short-term excursions during start-up. These actions have nearly eliminated our short-term emission limit compliance risk while plant availability remained above 90% for all four of our coal-fired plants at the Neil Simpson Complex. To eliminate the remaining potential for exceedances, an innovative trip logic mechanism was implemented to shut the power plant down if a predicted emission limit is to be exceeded. Similar efforts have been taken and similar results achieved with our natural gas fired combustion turbine sites as well.

Regional Haze (Impacts to the Wyodak Power Plant). The EPA Regional Haze rule was promulgated to improve visibility in our National Parks and Wilderness Areas. The State of Wyoming proposed controls in its Regional Haze State Implementation Plan (SIP) which allowed Pacificorp to install low-NO_x burners in its Wyodak Plant. The EPA did not agree with the State of Wyoming's determination and overruled it in a Federal Implementation Plan (FIP). The State of Wyoming and other interested parties are challenging the EPA's determination. If the challenge is unsuccessful, additional capital investment would be necessary to bring the Wyodak Plant into compliance. Our share of this capital investment would be approximately $40 million.

Mining. Operations at the WRDC mine must regularly address issues related to the proximity of the mine disturbance boundary to the City of Gillette, and to residential and industrial properties. Homeowner complaints and challenges to the permits may occur as mining operations move closer to residential areas. Specific concerns could include damage to wells, fugitive dust emissions, vibration and an emissions cloud from blasting.

Former Manufactured Gas Plants (FMGP). Federal and state laws authorize the EPA and other agencies to issue orders compelling potentially responsible parties to clean up sites that are determined to present an actual or potential threat to human health or the environment. Our gas utilities are managing FMGP sites in Iowa, Nebraska and Colorado. We are currently in discussions with EPA, state regulators, and/or other third-parties to determine the ultimate resolution to these sites.

Clean Power Plan. The EPA was directed to repeal, revise, and replace the Clean Power Plan rule. The EPA issued two public notices in the Federal Register late in 2017. The first identified the EPA's intent to repeal the rule and the second was issued to seek public input on proposals to replace the CPP with an Advanced Notice of Proposed Rule Making (ANPRM). Natural gas and renewable generation industries are pushing the EPA to replace the current rule. We will continue to monitor and comment on the proposals and take appropriate action related to any new or modified rules.

OSM Coal Combustion Residual Rule (CCR). The EPA issued the CCR that is currently effective and established requirements to protect surface and groundwater from impacts of coal ash impoundments. WRDC is exempt from the EPA CCR because coal ash is used for backfill reclamation in the areas previously mined. We would be subject to any proposed OSM CCR.

During the development of the OSM rule, it was anticipated that placing ash below groundwater levels would be disallowed. While our mining operations place ash below groundwater levels, the State of Wyoming gave us approval to grandfather this ash disposal in the Peerless Pit, with the Mine Plan Permit 232-T8, as a potential preventative measure to a new rule. As such, any risks associated with having to construct a new ash disposal site above groundwater and then complete backfilling the existing ash pit area to required reclamation levels are not applicable at this time.

Oil and Gas Segment Divestiture. Regulatory agencies placed a significant emphasis on regulating oil and gas activities over the past few years to address GHG and climate change concerns mainly due to the associated methane emissions. The regulatory activity significantly increased compliance risk. We will see relief in our compliance risk concerns with the divestiture of our oil and gas segment in 2018.

Environmental risk changes constantly with the implementation of new or modified regulations, changing stakeholder interests and needs, and through the introduction of innovative work practices and technologies. We assess risk annually and develop mitigation strategies to successfully and responsibly manage and ensure compliance across the enterprise. For additional information on environmental matters, see Item 1A and Note 19 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Other Properties

In addition to the facilities previously disclosed in Items 1 and 2, we own or lease several facilities throughout our service territories. Our owned facilities are as follows:

- In Rapid City, South Dakota, we have a new 220,000 square foot corporate headquarters building, Horizon Point, which was completed in the fourth quarter of 2017.
- In Arkansas, Nebraska, Iowa, Colorado, Kansas and Wyoming we own various office, service center, storage, shop and warehouse space totaling over 717,000 square feet utilized by our Gas Utilities.
- In South Dakota, Wyoming, Colorado and Montana we own various office, service center, storage, shop and warehouse space totaling approximately 237,000 square feet utilized by our Electric Utilities and Mining segments.

In addition to our owned properties, we lease 270,925 square feet of properties within our service areas.

Substantially all of the tangible utility properties of South Dakota Electric and Wyoming Electric are subject to liens securing first mortgage bonds issued by South Dakota Electric and Wyoming Electric, respectively.

Employees

At December 31, 2017, we had 2,744 full-time employees in continuing operations. Approximately 27% of our employees are represented by a collective bargaining agreement. We have not experienced any labor stoppages in recent years. At December 31, 2017, approximately 24% of our Electric Utilities and Gas Utilities employees were eligible for regular or early retirement.

The following table sets forth the number of employees included in continuing operations:

	Number of Employees
Corporate	484
Electric Utilities and Gas Utilities	2,199
Mining and Power Generation	61
Total	2,744

At December 31, 2017, certain employees of our Electric Utilities and Gas Utilities were covered by the following collective bargaining agreements:

Utility	Number of Employees	Union Affiliation	Expiration Date of Collective Bargaining Agreement
South Dakota Electric [(a)]	131	IBEW Local 1250	March 31, 2022
Wyoming Electric	42	IBEW Local 111	June 30, 2019
Colorado Electric	103	IBEW Local 667	April 15, 2018
Iowa Gas	115	IBEW Local 204	July 31, 2020
Kansas Gas [(c)]	17	Communications Workers of America, AFL-CIO Local 6407	December 31, 2019
Nebraska Gas	99	IBEW Local 244	March 13, 2022
Nebraska Gas [(b)]	143	CWA Local 7476	October 30, 2019
Wyoming Gas [(b)]	86	CWA Local 7476	October 30, 2019
Total	736		

(a) On January 26, 2017, South Dakota Electric's contract was ratified with an expiration date of March 31, 2022.
(b) In the 2016 negotiations with the CWA Local 7476, the union agreed to disclaim their interest in Colorado Gas employees and to split the remaining bargaining unit into two distinct bargaining units, Nebraska Gas and Wyoming Gas.
(c) Kansas Gas completed a wage adjustment that was ratified on November 15, 2017.

ITEM 1A. RISK FACTORS

The nature of our business subjects us to a number of uncertainties and risks. The following risk factors and other risk factors that we discuss in our periodic reports filed with the SEC should be considered for a better understanding of our Company. These important factors and other matters discussed herein could cause our future actual results or outcomes to differ materially.

OPERATING RISKS

Our financial performance depends on the successful operation of our facilities. If the risks involved in our operations are not appropriately managed or mitigated, our operations may not be successful and this could adversely affect our results of operations.

Operating electric generating facilities, the coal mine and electric and natural gas distribution systems involves risks, including:

- Disrupted transmission and distribution. We depend on transmission and distribution facilities, including those operated by unaffiliated parties, to deliver the electricity and gas that we sell to our retail and wholesale customers. If transmission is interrupted, our ability to sell or deliver product and satisfy our contractual obligations may be hindered;

- Interruptions to supply of fuel and other commodities used in generation and distribution. Our utilities purchase fuel from a number of suppliers. Our results of operations could be negatively impacted by disruptions in the delivery of fuel due to various factors, including but not limited to, transportation delays, labor relations, weather and environmental regulations, which could limit our utilities' ability to operate their facilities;

- Electricity is dangerous for employees and the general public should they come in contact with power lines or electrical service facilities and equipment. Natural conditions and other disasters such as wind, lightning and winter storms can cause wildfires, pole failures and associated property damage and outages;

- Operating hazards such as leaks, mechanical problems and accidents, including explosions, affecting our natural gas distribution system which could impact public safety, reliability and customer confidence;

- Operational limitations imposed by environmental and other regulatory requirements;

- Breakdown or failure of equipment or processes, including those operated by PacifiCorp at the Wyodak Plant;

- Labor relations. Approximately 27% of our employees are represented by a total of eight collective bargaining agreements;

- Our ability to transition and replace our retirement-eligible utility employees. At December 31, 2017, approximately 24% of our Electric Utilities and Gas Utilities employees were eligible for regular or early retirement;

- Inability to recruit and retain skilled technical labor; and

- Disruption in the functioning of our information technology and network infrastructure which are vulnerable to disability, failures and unauthorized access. If our information technology systems were to fail and we were unable to recover in a timely manner, we would be unable to fulfill critical business functions.

Changes in the interpretation of the Tax Cuts and Jobs Act ("TCJA") could adversely affect us.

On December 22, 2017, the TCJA was signed into law, significantly reforming the U.S. Internal Revenue Code. The TCJA, among other things, includes a decrease in the U.S. federal corporate tax rate from 35% to 21%, imposes significant additional limitations on the deductibility of interest, allows for the expensing of capital expenditures, and modifies or repeals many business deductions and credits. The new tax law contains several provisions that impacted our 2017 financial results and will impact the Company into the future. As allowed under SEC Staff Accounting Bulletin No. 118 (SAB 118), the Company has recorded provisional income tax amounts as of December 31, 2017 for changes pursuant to the TCJA related to depreciation, for which the impacts could not be finalized upon issuance of the Company's financial statements but reasonable estimates could be determined.

In accordance with ASC 740, the enactment of the law on December 22, 2017 required revaluation of federal deferred tax assets and liabilities using the new lower corporate statutory tax rate of 21%. As a result of the revaluation, deferred tax assets and liabilities were reduced by approximately $309 million. Of the $309 million, approximately $301 million is related to our regulated utilities and is reclassified to a regulatory liability. This regulatory liability will generally be amortized over the remaining life of the related assets using the normalization principles as specifically prescribed in the TCJA. On a consolidated financial statement basis, the revaluation of deferred tax assets and liabilities to the 21% federal corporate tax rate that are not subject to the regulatory construct resulted in a one-time, non-cash, income tax benefit of approximately $8 million in 2017.

The TCJA includes provisions limiting interest deductibility in certain circumstances. While we expect to maintain deductibility of interest expense, the lower tax rate reduces the tax benefits associated with interest deductibility on holding company debt that is not recovered in the regulatory construct.

We are working with utility regulators in each of the states we serve to provide benefits of tax reform to our customers. We expect an increase in working capital requirements as a result of complying with the TCJA and the impact of providing TCJA benefits to customers. The lower tax rate effective January 1, 2018, will negatively impact the Company’s cash flows by approximately $35 million to $45 million annually for the next several years.

If we are unable to obtain reasonable outcomes with our utility regulators in passing benefits of the TCJA back to customers, or if our interpretations on the provisions of depreciation or interest deductibility in the TCJA change, our results of operations, financial position and cash flows could be materially impacted.

Construction, expansion, refurbishment and operation of power generating and transmission and resource extraction facilities involve significant risks which could reduce profitability.

The construction, expansion, refurbishment and operation of power generating and transmission and resource extraction facilities involve many risks, including:

- The inability to obtain required governmental permits and approvals along with the cost of complying with or satisfying conditions imposed upon such approvals;
- Contractual restrictions upon the timing of scheduled outages;
- The cost of supplying or securing replacement power during scheduled and unscheduled outages;
- The unavailability or increased cost of equipment;
- The cost of recruiting and retaining or the unavailability of skilled labor;
- Supply interruptions, work stoppages and labor disputes;
- Increased capital and operating costs to comply with increasingly stringent environmental laws and regulations;
- Opposition by members of public or special-interest groups;
- Weather interferences;
- Availability and cost of fuel supplies;
- Unexpected engineering, environmental and geological problems; and
- Unanticipated cost overruns.

The ongoing operation of our facilities involves many of the risks described above, in addition to risks relating to the breakdown or failure of equipment or processes and performance below expected levels of output or efficiency. New plants may employ recently developed and technologically complex equipment, including newer environmental emission control technology. Any of these risks could cause us to operate below expected capacity levels, which in turn could reduce revenues, increase expenses or cause us to incur higher operating and maintenance costs and penalties. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance and

our rights under warranties or performance guarantees may not be timely or adequate to cover lost revenues, increased expenses, liability or liquidated damage payments.

Operating results can be adversely affected by variations from normal weather conditions.

Our utility businesses are seasonal businesses and weather patterns can have a material impact on our operating performance. Demand for electricity is typically greater in the summer and winter months associated with cooling and heating. Demand for natural gas depends heavily upon winter-weather patterns throughout our service territory and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our utility operations have historically generated lower revenues and income when weather conditions are cooler than normal in the summer and warmer than normal in the winter. Demand for natural gas is also impacted by summer weather patterns that are cooler than normal and provide higher than normal precipitation; both of which can reduce natural gas demand for irrigation. Unusually mild summers and winters therefore could have an adverse effect on our results of operations, financial position and cash flows.

Our businesses are located in areas that could be subject to seasonal natural disasters such as severe snow and ice storms, flooding and wildfires. These events could result in interruption of our business, damage to our property such as power lines and substations, and repair and clean-up costs. We may not be able to recover the costs incurred in restoring transmission and distribution property following these natural disasters through a change in our regulated rates thereby resulting in a negative impact on our results of operations, financial position and cash flows.

Our Mining operations are subject to operating risks that are beyond our control which could affect our profitability and production levels. Our surface mining operations could be disrupted or materially affected due to adverse weather or natural disasters such as heavy snow, strong winds, rain or flooding.

Prices for some of our products and services as well as a portion of our operating costs are volatile and may cause our revenues and expenses to fluctuate significantly.

A portion of our net income is attributable to sales of contract and off-system wholesale electricity and natural gas. Energy prices are influenced by many factors outside our control, including, among other things, fuel prices, transmission constraints, supply and demand, weather, general economic conditions, and the rules, regulations and actions of system operators in those markets. Moreover, unlike most other commodities, electricity cannot be stored and therefore must be produced concurrently with its use. As a result, wholesale power markets may be subject to significant, unpredictable price fluctuations over relatively short periods of time.

Our Mining operations require reliable supplies of replacement parts, explosives, fuel, tires and steel-related products. If the cost of these increase significantly, or if sources of supplies and mining equipment become unavailable to meet our replacement demands, our productivity and profitability could be lower than our current expectations.

Our revenues, results of operations and financial condition are impacted by customer growth and usage in our service territories and may fluctuate with current economic conditions, emerging technologies or responses to price increases.

Our revenues, results of operations and financial condition are impacted by demand in our service territories. Customer growth and usage may be impacted by a number of factors, including the voluntary reduction of consumption of electricity and natural gas by our customers in response to increases in prices and demand-side management programs, economic conditions impacting decreases in customers' disposable income and the use of distributed generation resources or other emerging technologies. Continued technological improvements may make customer and third-party distributed generation and energy storage systems, including fuel cells, micro-turbines, wind turbines, solar cells and batteries, more cost effective and feasible for our customers. If more customers utilize their own generation, demand for energy from us would decline. Such developments could affect the price of energy and delivery of energy, require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Each of these factors could materially affect our results of operations, financial position and cash flows.

Our operations rely on storage and transportation assets owned by third parties to satisfy our obligations.

Our Electric Utilities, Gas Utilities and Power Generation segments rely on pipeline companies and other owners of gas storage facilities to deliver natural gas to customers, to supply our natural gas-fired power plants and to hedge commodity costs. If storage capacity is inadequate or transportation is disrupted, our ability to satisfy our obligations may be hindered. As a result,

we may be responsible for damages incurred by our counterparties, such as the additional cost of acquiring alternative supply at then-current market rates, or for penalties imposed by state regulatory authorities.

Our utilities are subject to pipeline safety and system integrity laws and regulations that may require significant capital expenditures or significant increases in operating costs.

Compliance with pipeline safety and system integrity laws and regulations, or future changes in these laws and regulations, may result in increased capital, operating and other costs which may not be recoverable in a timely manner from customers in rates. Failure to comply may result in fines, penalties, or injunctive measures that would not be recoverable from customers in rates and could result in a material impact on our results of operations, financial position and cash flows.

Our energy production, transmission and distribution activities, and our storage facilities for our natural gas involve numerous risks that may result in accidents and other catastrophic events that could give rise to additional costs and cause a substantial loss to us.

Inherent in our natural gas and electricity transmission and distribution activities, as well as in our transportation and storage of natural gas and our Mining operations, are a variety of hazards and operating risks, such as leaks, blowouts, fires, releases of hazardous materials, explosions and operational problems. These events could impact the safety of employees or others and result in injury or loss of human life, and cause significant damage to property or natural resources (including public lands), environmental pollution, impairment of our operations and substantial financial losses to us. Particularly for our transmission and distribution lines located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the damages resulting from any such events could be substantial. While we maintain liability and property insurance coverage, such policies are subject to certain limits and deductibles. The occurrence of any of these events not fully covered by our insurance could have a material adverse effect on our financial position, results of operations or cash flows.

Threats of terrorism and catastrophic events that could result from terrorism, or individuals and/or groups attempting to disrupt our businesses, or the businesses of third parties, may impact our operations in unpredictable ways.

Terrorist acts or other similar events could harm our businesses by limiting their ability to generate, purchase or transmit power and by delaying their development and construction of new generating facilities and capital improvements to existing facilities. These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure our assets and could adversely affect our operations by contributing to disruption of supplies and markets for natural gas, oil and other fuels. They could also impair our ability to raise capital by contributing to financial instability and lower economic activity.

The implementation of security guidelines and measures and maintenance of insurance, to the extent available, addressing such activities could increase costs. These types of events could materially adversely affect our financial results. In addition, these types of events could require significant management attention and resources and could adversely affect our reputation among customers and the public.

A cyber attack may disrupt our operations, or lead to a loss or misuse of confidential and proprietary information and create a potential liability.

We use and operate sophisticated information technology systems and network infrastructure. In addition, in the ordinary course of business, we collect and retain sensitive information including personal information about our customers and employees. Cyber attacks targeting our electronic control systems used at our generating facilities and for electric and gas distribution systems, could result in a full or partial disruption of our electric and/or gas operations. Cyber attacks targeting other key information technology systems could further add to a full or partial disruption of our operations. Any disruption of these operations could result in a loss of service to customers and a significant decrease in revenues, as well as significant expense to repair system damage and remedy security breaches. Any theft, loss and/or fraudulent use of customer, shareowner, employee or proprietary data as a result of a cyber attack could subject us to significant litigation, liability and costs, as well as adversely impact our reputation with customers and regulators, among others.

We have instituted security measures and safeguards to protect our operational systems and information technology assets, including certain safeguards required by FERC. The security measures and safeguards we have implemented may not always be effective due to the evolving nature and sophistication of cyber attacks. Despite our implementation of security measures and safeguards, all of our information technology systems are vulnerable to disability, failures or unauthorized access, including cyber attacks. If our information technology systems were to fail or be breached by a cyber attack or a computer

virus and be unable to recover in a timely way, we would be unable to fulfill critical business functions and sensitive confidential and other data could be compromised which could have a material adverse effect not only on our financial results, but on our public reputation as well.

Increased risks of regulatory penalties could negatively impact our results of operations, financial position or liquidity.

Business activities in the energy sector are heavily regulated, primarily by agencies of the federal government. Agencies that historically sought voluntary compliance, or issued non-monetary sanctions, now employ mandatory civil penalty structures for regulatory violations. The FERC, NERC, CFTC, EPA, OSHA, SEC and MSHA may impose significant civil and criminal penalties to enforce compliance requirements relative to our business, which could have a material adverse effect on our operations and/or our financial results.

Certain Federal laws, including the Migratory Bird Act and the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for non-permitted activities that result in harm to or harassment of certain protected animals, including damage to their habitats. If such species are located in an area in which we conduct operations, or if additional species in those areas become subject to protection, our operations and development projects, particularly transmission, generation, wind and pipeline projects, could be restricted or delayed, or we could be required to implement expensive mitigation measures.

Our current or future development and expansion activities may not be successful, which could impair our ability to execute our growth strategy.

Execution of our growth plan is dependent on successful ongoing and future development and expansion activities. We can provide no assurance that we will be able to complete development projects or expansion activities we undertake or continue to develop attractive opportunities for growth. Factors that could cause our development and expansion activities to be unsuccessful include:

- Our inability to obtain required governmental permits;
- Our inability to secure adequate utility rates through regulatory proceedings;
- Our inability to obtain financing on acceptable terms, or at all;
- The possibility that one or more credit rating agencies would downgrade our issuer credit rating to below investment grade, thus increasing our cost of doing business;
- Our inability to attract and retain management or other key personnel;
- Our inability to negotiate acceptable construction, fuel supply, power sales or other material agreements;
- Reduced growth in the demand for utility services in the markets we serve;
- Changes in federal, state, local or tribal laws and regulations, particularly those which would make it more difficult or costly to fully develop our coal reserves or our power generation capacity;
- Fuel prices or fuel supply constraints;
- Pipeline capacity and transmission constraints;
- Competition within our industry and with producers of competing energy sources; and
- Changes in tax rates and policies.

Utilities

Regulatory commissions may refuse to approve some or all of the utility rate increases we have requested or may request in the future, or may determine that amounts passed through to customers were not prudently incurred and therefore are not recoverable.

Our regulated Electric Utilities and Gas Utilities are subject to cost-of-service regulation and earnings oversight from federal and state utility commissions. This regulatory treatment does not provide any assurance as to achievement of desired earnings levels. Our retail electric and gas utility rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. The rates that we are allowed to charge may or may not match our related costs and allowed return on invested capital at any given time. While rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that the state public utility commissions will judge all of our costs, including our direct and allocated borrowing and debt service costs, to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that produce a full recovery of our costs and the return on invested capital allowed by the applicable state public utility commission.

To some degree, each of our Electric and Gas Utilities are permitted to recover certain costs (such as increased fuel and purchased power costs) without having to file a rate case. To the extent we are able to pass through such costs to our customers and a state public utility commission subsequently determines that such costs should not have been paid by the customers; we may be required to refund such costs. Any such costs not recovered through rates, or any such refund, could adversely affect our results of operations, financial position or cash flows.

If market or other conditions adversely affect operations or require us to make changes to our business strategy in any of our utility businesses, we may be forced to record a non-cash goodwill impairment charge. Any significant impairment of our goodwill related to these utilities would cause a decrease in our assets and a reduction in our net income and shareholders' equity.

We had approximately $1.3 billion of goodwill on our consolidated balance sheets as of December 31, 2017. A substantial portion of the goodwill is related to the SourceGas Acquisition and the Aquila Transaction. If we make changes in our business strategy or if market or other conditions adversely affect operations in any of our businesses, we may be forced to record a non-cash impairment charge, which would reduce our reported assets, net income and shareholders' equity. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying value of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including: future business operating performance, changes in economic conditions and interest rates, regulatory, industry or market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects could affect the fair value of one or more business segments, which may result in an impairment charge.

Municipal governments may seek to limit or deny franchise privileges which could inhibit our ability to secure adequate recovery of our investment in assets subject to condemnation.

Municipal governments within our utility service territories possess the power of condemnation and could establish a municipal utility within a portion of our current service territories by limiting or denying franchise privileges for our operations and exercising powers of condemnation over all or part of our utility assets within municipal boundaries. Although condemnation is a process that is subject to constitutional protections requiring just and fair compensation, as with any judicial procedure, the outcome is uncertain. If a municipality sought to pursue this course of action, we cannot assure that we would secure adequate recovery of our investment in assets subject to condemnation.

Mining

If the assumptions underlying our reclamation and mine closure obligations are materially inaccurate, our costs could be significantly greater than anticipated or be incurred sooner than anticipated.

We conduct surface mining operations that are subject to operations, reclamation and closure standards. We estimate our total reclamation liabilities based on permit requirements, engineering studies and our engineering expertise related to these requirements. The estimate of ultimate reclamation liability is reviewed periodically by our management and engineers and by government regulators. The estimated liability can change significantly if actual costs vary from our original assumptions or if government regulations change significantly. GAAP requires that asset retirement obligations be recorded as a liability based on fair value, which reflects the present value of the estimated future cash flows. In estimating future cash flows, we consider the estimated current cost of reclamation and apply inflation rates. The resulting estimated reclamation obligations could change significantly if actual amounts or the timing of these expenses change significantly from our assumptions, which could have a material adverse effect on our results of operations and financial position.

Estimates of the quality and quantity of our coal reserves may change materially due to numerous uncertainties inherent in three-dimensional structural modeling, and any inaccuracies in interpretation or modeling could materially affect the estimated quantity and quality of our reserves.

The process of estimating coal reserves is uncertain and requires interpretations and modeling. Significant inaccuracies in interpretation or modeling could materially affect the quantity and quality of our reserve estimates. The accuracy of reserve estimates is a function of engineering and geological interpretation, conditions encountered during actual reserve recovery and undetected deposit anomalies. Variance from the assumptions used and drill hole modeling density could result in additions or deletions from our volume estimates. In addition, future environmental, economic or geologic changes may occur or become known that require reserve revisions either upward or downward from prior reserve estimates.

FINANCING RISKS

Our credit ratings could be lowered below investment grade in the future. If this were to occur, it could impact our access to capital, cost of capital and other operating costs.

Our issuer credit rating is Baa2 (Stable outlook) by Moody’s; BBB (Stable outlook) by S&P; and BBB+ (Stable outlook) by Fitch. Reduction of our credit ratings could impair our ability to refinance or repay our existing debt and to complete new financings on reasonable terms, or at all. A credit rating downgrade, particularly to a sub-investment grade, could also result in counterparties requiring us to post additional collateral under existing or new contracts or trades. In addition, a ratings downgrade would increase our interest expense under some of our existing debt obligations, including borrowings under our credit facilities.

Derivatives regulations could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.

Dodd-Frank contains significant derivatives regulations, including a requirement that certain transactions be cleared resulting in a requirement to post cash collateral (commonly referred to as “margin”) for such transactions. Dodd-Frank provides for a potential exception from these clearing and cash collateral requirements for commercial end-users such as utilities and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions.

We use natural gas derivative instruments for our hedging activities for our Gas and Electric Utilities’ operations. We may also use interest rate derivative instruments to minimize the impact of interest rate fluctuations. As a result of Dodd-Frank regulations promulgated by the CFTC, we may be required to post collateral to clearing entities for certain swap transactions we enter into. In addition our exchange-traded futures contracts are subject to futures margin posting requirements, which could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price and interest rate uncertainty and to protect cash flows. Requirements to post collateral may cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes, or may require us to increase our level of debt. In addition, a requirement for our counterparties to post collateral could result in additional costs being passed on to us, thereby decreasing our profitability.

Our hedging activities that are designed to protect against commodity price and financial market risks may cause fluctuations in reported financial results due to accounting requirements associated with such activities.

We use various financial contracts and derivatives, including futures, forwards, options and swaps to manage commodity price and financial market risks. The timing of the recognition of gains or losses on these economic hedges in accordance with GAAP does not always match up with the gains or losses on the commodities or assets being hedged. The difference in accounting can result in volatility in reported results, even though the expected profit margin may be essentially unchanged from the dates the transactions were consummated.

Our use of derivative financial instruments could result in material financial losses.

From time to time, we have sought to limit a portion of the potential adverse effects resulting from changes in commodity prices and interest rates by using derivative financial instruments and other hedging mechanisms. To the extent that we hedge our commodity price and interest rate exposures, we forgo the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though they are closely monitored by management, our hedging activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is economically imperfect, commodity prices or interest rates move unfavorably related to our physical or financial positions, or hedging policies and procedures are not followed.

Market performance or changes in other assumptions could require us to make significant unplanned contributions to our pension plans and other postretirement benefit plans. Increasing costs associated with our defined benefit retirement plans may adversely affect our results of operations, financial position or liquidity.

As discussed in Note 18 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K, we have one defined benefit pension plan (the pension plan is closed to new employees and frozen for certain employees who did not meet age and service based criteria) and several defined post-retirement healthcare plans and non-qualified retirement plans that cover certain eligible employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements and the expense recognized related to these plans. These estimates and assumptions may change based on actual return on plan assets, changes in interest rates and any changes in governmental regulations.

We have a holding company corporate structure with multiple subsidiaries. Corporate dividends and debt payments are dependent upon cash distributions to the holding company from the subsidiaries.

As a holding company, our investments in our subsidiaries are our primary assets. Our operating cash flow and ability to service our indebtedness depend on the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends or advances. Our subsidiaries are separate legal entities that have no obligation to make any funds available for that purpose, whether by dividends or otherwise. In addition, each subsidiary’s ability to pay dividends to us depends on any applicable contractual or regulatory restrictions that may include requirements to maintain minimum levels of cash, working capital, equity or debt service funds.

There is no assurance as to the amount, if any, of future dividends because they depend on our future earnings, capital requirements and financial condition and are subject to declaration by the Board of Directors. Our operating subsidiaries have certain restrictions on their ability to transfer funds in the form of dividends or loans to us. See “Liquidity and Capital Resources” within Management’s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K for further information regarding these restrictions and their impact on our liquidity.

We may be unable to obtain financing on reasonable terms needed to refinance debt, fund planned capital expenditures or otherwise execute our operating strategy.

Our ability to execute our operating strategy is highly dependent upon our access to capital. Historically, we have addressed our liquidity needs (including funds required to make scheduled principal and interest payments, refinance debt and fund working capital and planned capital expenditures) with operating cash flow, borrowings under credit facilities, proceeds of debt and equity offerings, and proceeds from asset sales. Our ability to access the capital markets and the costs and terms of available financing depend on many factors, including changes in our credit ratings, changes in the federal or state regulatory environment affecting energy companies, volatility in commodity or electricity prices, and general economic and market conditions.

In addition, because we are a holding company and our utility assets are owned by our subsidiaries, if we are unable to adequately access the credit markets, we could be required to take additional measures designed to ensure that our utility subsidiaries are adequately capitalized to provide safe and reliable service. Possible additional measures would be evaluated in the context of then-prevailing market conditions, prudent financial management and any applicable regulatory requirements.

National and regional economic conditions may cause increased counterparty credit risk, late payments and uncollectible accounts, which could adversely affect our results of operations, financial position and liquidity.

A future recession may lead to an increase in late payments from retail, commercial and industrial utility customers, as well as from our non-utility customers. If late payments and uncollectible accounts increase, earnings and cash flows from our continuing operations may be reduced.

Our ability to obtain insurance and the terms of any available insurance coverage could be adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers. Our insurance coverage may not provide protection against all significant losses.

Our ability to obtain insurance, as well as the cost of such insurance, could be impacted by developments affecting insurance businesses, international, national, state or local events, as well as the financial condition of insurers. Insurance coverage may not continue to be available at all, or at rates or on terms similar to those presently available to us. A loss for which we are not fully insured could materially and adversely affect our financial results. Our insurance may not be sufficient or effective under all circumstances and against all hazards or liabilities to which the Company may be subject, including but not limited to environmental hazards, fire-related liability from natural events or inadequate facility maintenance, distribution property losses, cyber-security risks and dangers that exist in the gathering and transportation of gas in pipelines.

Increasing costs associated with our health care plans and other benefits may adversely affect our results of operations, financial position or liquidity.

The costs of providing health care benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs related to health care plans for our employees and former employees, will continue to rise. Significant regulatory developments have, and likely will continue to, require changes to our current employee benefit plans and in our administrative and accounting processes, as well as changes to the cost of our plans, and the increasing costs and funding requirements associated with our health care plans may adversely affect our results of operations, financial position or liquidity.

Our electric and gas utility rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. Within our utility rates we have generally recovered the cost of providing employee benefits. As benefit costs continue to rise, there can be no assurance that the state public utility commissions will allow recovery.

An effective system of internal control may not be maintained, leading to material weaknesses in internal control over financial reporting.

Section 404 of the Sarbanes-Oxley Act of 2002 requires management to make an assessment of the design and effectiveness of internal controls. Our independent registered public accounting firm is required to attest to the effectiveness of these controls. During their assessment of these controls, management or our independent registered public accounting firm may identify areas of weakness in control design or effectiveness, which may lead to the conclusion that a material weakness in internal control exists. Any control deficiencies we identify in the future could adversely affect our ability to report our financial results on a timely and accurate basis, which could result in a loss of investor confidence in our financial reports or have a material adverse effect on our ability to operate our business or access sources of liquidity.

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system’s objectives will be met. If we are unable to assert that our internal controls over financial reporting are effective, market perception of our business, operating results and stock price could be adversely affected.

ENVIRONMENTAL RISKS

Federal and state laws concerning GHG regulations and air emissions may materially increase our generation and production costs and could render some of our generating units uneconomical to operate and maintain.

We own and operate regulated and non-regulated fossil-fuel generating plants in South Dakota, Wyoming and Colorado. Developments under federal and state laws and regulations governing air emissions from fossil-fuel generating plants may result in more stringent emission limitations, which could have a material impact on our costs of operations. Various pending or final state and EPA regulations that will impact our facilities are also discussed in Item 1 of this Annual Report on Form 10-K under the section "Environmental Matters."

Due to uncertainty as to the final outcome of federal climate change legislation, legal challenges, state clean power plan developments or regulatory changes under the Clean Air Act, we cannot definitively estimate the effect of GHG legislation or regulation on our results of operations, cash flows or financial position.

New or more stringent regulations or other energy efficiency requirements could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets, the acquisition or development of additional energy supply from renewable resources, the closure or reduction of load of coal-fired power generation facilities and potential increased load of our combined cycle natural gas-fired generation units. To the extent our regulated fossil-fuel generating plants are included in rate base we will attempt to recover costs associated with complying with emission standards or other requirements. We will also attempt to recover the emission compliance costs of our non-regulated fossil-fuel generating plants from utility and other purchasers of the power generated by those non-regulated power plants. Any unrecovered costs could have a material impact on our results of operations and financial condition. In addition, future changes in environmental regulations governing air emissions could render some of our power generating units more expensive or uneconomical to operate and maintain.

The costs to achieve or maintain compliance with existing or future governmental laws, regulations or requirements, and any failure to do so, could adversely affect our results of operations, financial position or liquidity.

Our business segments are subject to numerous environmental laws and regulations affecting many aspects of present and future operations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations may result in increased capital, operating and other costs. These laws and regulations generally require the business segments to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations may require significant expenditures, including expenditures for cleanup costs and damages arising from contaminated properties. Failure to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets.

The business segments may not be successful in recovering capital and operating costs incurred to comply with new environmental regulations through existing regulatory rate structures and contracts with customers. More stringent environmental laws or regulations could result in additional costs of operation for existing facilities or impede the development of new facilities. Although it is not expected that the costs to comply with current environmental regulations will have a material adverse effect on the business segments' financial position, results of operations or cash flows, future environmental compliance costs could have a significant negative impact..

The characteristics of coal may make it difficult for coal users to comply with various environmental standards related to coal combustion or utilization and the use of alternative energy sources for power generation as mandated by states could reduce coal consumption.

Future regulations may require further reductions in emissions of mercury, hazardous pollutants, SO_2, NO_x, volatile organic compounds, particulate matter and GHG, which are released into the air when coal is burned. These requirements could require the installation of costly emission control technology or the implementation of other measures. Reductions in mercury emissions required by EPA's MATS rule, will likely require some power plants to install new equipment, at substantial cost, or discourage the use of certain coals containing higher levels of mercury.

Coal competes with other energy sources, such as natural gas, wind, solar and hydropower. The EPA was directed to repeal, revise and replace the CPP rule. At this time, it is not known what effect this will have on coal as a domestic energy source, and could have a significant impact on our mining operations.

Existing or proposed legislation focusing on emissions enacted by the United States or individual states could make coal a less attractive fuel alternative for our customers and could impose a tax or fee on the producer of the coal. If our customers decrease the volume of coal they purchase from us or switch to alternative fuels as a result of existing or future environmental regulations aimed at reducing emissions, our operations and financial results could be adversely impacted.

Oil and Gas (Discontinued Operations)

If the risks involved in our Oil and Gas operations are not appropriately managed or mitigated through final sale dates, or if the divestiture of this business segment does not occur as currently anticipated, we could incur costs and/or additional write-downs of the carrying value of our natural gas and oil properties.

As of February 23, 2018, we have either closed transactions or signed contracts to sell more than 90 percent of our oil and gas properties. We expect to conclude the sale of all of our remaining oil and gas assets by mid-year 2018. Until the sale transactions are final, we continue to own and operate these assets and are exposed to the risks associated with those operations. In addition, while we have signed agreements for the significant majority of the properties, until the sales are closed, there is a risk that the transactions do not occur as planned. Additional operating costs, additional write-down of carrying value or the non-closure of sale agreements as currently signed could result in an adverse impact to our financial results.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings is incorporated herein by reference to the “Legal Proceedings” sub-caption within Item 8, Note 19, “Commitments and Contingencies”, of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Sections 1503(a) of Dodd-Frank is included in Exhibit 95 of this Annual Report.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the New York Stock Exchange under the symbol BKH. As of December 31, 2017, we had 3,732 common shareholders of record and approximately 25,000 beneficial owners, representing all 50 states, the District of Columbia and 7 foreign countries.

We have paid a regular quarterly cash dividend each year since the incorporation of our predecessor company in 1941 and expect to continue paying a regular quarterly dividend for the foreseeable future. At its January 31, 2018 meeting, our Board of Directors declared a quarterly dividend of $0.475 per share, equivalent to an annual dividend of $1.90 per share. The 2018 equivalent rate of $1.90 per share would mark 2018 as the 48th consecutive annual dividend increase for the Company.

For additional discussion of our dividend policy and factors that may limit our ability to pay dividends, see "Liquidity and Capital Resources" under Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations in this Annual Report on Form 10-K.

Quarterly dividends paid and the high and low prices for our common stock, as reported in the New York Stock Exchange Composite Transactions, for the last two years were as follows:

Year ended December 31, 2017	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$ 0.445	$ 0.445	$ 0.445	$ 0.475
Common stock prices				
High	$ 67.02	$ 72.02	$ 71.01	$ 69.79
Low	$ 60.02	$ 65.37	$ 67.08	$ 57.01

Year ended December 31, 2016	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Dividends paid per share	$ 0.420	$ 0.420	$ 0.420	$ 0.420
Common stock prices				
High	$ 61.13	$ 63.53	$ 64.58	$ 62.83
Low	$ 44.65	$ 56.16	$ 56.86	$ 54.76

UNREGISTERED SECURITIES ISSUED

There were no unregistered securities sold during 2017.

ISSUER PURCHASES OF EQUITY SECURITIES

There were no equity securities acquired for the twelve months ended December 31, 2017.

ITEM 6. SELECTED FINANCIAL DATA

(Minor differences may result due to rounding)

Years Ended December 31, (dollars in thousands, except per share amounts)	2017	2016	2015	2014	2013
Total Assets	$ 6,658,902	$ 6,541,773	$ 4,626,643	$ 4,216,752	$ 3,820,875
Property, Plant and Equipment					
Total property, plant and equipment	$ 5,567,518	$ 5,315,296	$ 3,849,309	$ 3,606,931	$ 3,412,623
Accumulated depreciation and depletion	(1,026,088)	(929,119)	(794,695)	(714,762)	(687,010)
Total property, plant and equipment, net	$ 4,541,430	$ 4,386,177	$ 3,054,614	$ 2,892,169	$ 2,725,613
Capital Expenditures					
Continuing Operations	$ 337,689	$ 460,450	$ 289,896	$ 281,828	$ 314,847
Discontinued Operations	23,222	6,669	168,925	109,439	64,687
Total Capital Expenditures	$ 360,911	$ 467,119	$ 458,821	$ 391,267	$ 379,534
Capitalization (excluding noncontrolling interests)					
Current maturities of long-term debt	$ 5,743	$ 5,743	$ —	$ 275,000	$ —
Notes payable	211,300	96,600	76,800	75,000	82,500
Long-term debt, net of current maturities and deferred financing costs	3,109,400	3,211,189 (a)	1,853,682	1,255,953	1,383,714
Common stock equity	1,708,974	1,614,639 (b)	1,465,867 (b)	1,353,884	1,283,500
Total capitalization	$ 5,035,417	$ 4,928,171	$ 3,396,349	$ 2,959,837	$ 2,749,714
Capitalization Ratios					
Short-term debt, including current maturities	4%	2%	2%	12%	3%
Long-term debt, net of current maturities	62%	65% (a)	55%	42%	50%
Common stock equity	34%	33%	43%	46%	47%
Total	100%	100%	100%	100%	100%
Total Operating Revenues	$ 1,680,266	$ 1,538,916	$ 1,261,322	$ 1,338,456	$ 1,220,968
Net Income Available for Common Stock					
Electric Utilities	$ 110,082	$ 85,827	$ 77,579	$ 57,270	$ 49,003
Gas Utilities	65,795	59,624	39,306	44,151	35,838
Power Generation	46,479 (c)	25,930 (c)	32,650	28,516	16,288 (c)
Mining	14,386	10,053	11,870	10,452	6,327
Corporate and intersegment eliminations	(42,609) (d)	(44,302) (d)	(19,857) (d)	(7,927)	5,855 (d)
Income (loss) from continuing operations available for common stock	194,133	137,132	141,548	132,462	113,311
Income (loss) from discontinued operations, net of tax (b)	(17,099)	(64,162)	(173,659)	(1,573)	4,112 (e)
Net income (loss) available for common stock	$ 177,034	$ 72,970	$ (32,111)	$ 130,889	$ 117,423

SELECTED FINANCIAL DATA continued

Years Ended December 31, (dollars in thousands, except per share amounts)	2017	2016	2015	2014	2013	
Dividends Paid on Common Stock	$ 96,744	$ 87,570	$ 72,604	$ 69,636	$ 67,587	
Common Stock Data[f] (in thousands)						
Shares outstanding, average basic	53,221	51,922	45,288	44,394	44,163	
Shares outstanding, average diluted	55,120	53,271	45,288	44,598	44,419	
Shares outstanding, end of year	53,541	53,382	51,192	44,672	44,499	
Earnings (Loss) Per Share of Common Stock (in dollars)						
Basic earnings (loss) per average share -						
Continuing operations	$ 3.92	$ 2.83	$ 3.12	$ 2.98	$ 2.57	
Discontinued operations [b]	(0.32)	(1.23)	(3.83)	(0.04)	0.09	[e]
Non-controlling interest	(0.27)	(0.19)	—	—	—	
Total	$ 3.33	$ 1.41	$ (0.71)	$ 2.94	$ 2.66	
Diluted earnings (loss) per average share -						
Continuing operations	$ 3.78	$ 2.75	$ 3.12	$ 2.97	$ 2.55	
Discontinued operations [b]	(0.31)	(1.20)	(3.83)	(0.04)	0.09	
Non-controlling interest	(0.26)	(0.18)	—	—	—	
Total	$ 3.21	$ 1.37	$ (0.71)	$ 2.93	$ 2.64	
Dividends Declared per Share	$ 1.81	$ 1.68	$ 1.62	$ 1.56	$ 1.52	
Book Value Per Share, End of Year	$ 31.92	$ 30.25	$ 28.63	$ 30.31	$ 28.84	
Return on Average Equity [h]	11.7%	8.9%	10.0%	10.0%	9.1%	

SELECTED FINANCIAL DATA continued

Years ended December 31,	2017	2016	2015	2014	2013
Operating Statistics:					
Generating capacity (MW):					
Electric Utilities (owned generation)	941	941	841	841	790
Electric Utilities (purchased capacity)	110	110	210	210	150
Power Generation (owned generation)	269	269	269	269	309
Total generating capacity	1,320	1,320	1,320	1,320	1,249
Electric Utilities:					
MWh sold:					
Retail electric	5,189,084	5,140,519	4,990,594	4,775,808	4,642,254
Contracted wholesale	722,659	246,630	260,893	340,871	357,193
Wholesale off-system	661,263	769,843	1,000,085	1,118,641	1,456,762
Total MWh sold	6,573,006	6,156,992	6,251,572	6,235,320	6,456,209
Gas Utilities:					
Gas sold (Dth)	87,816,522	79,165,742	56,638,299	64,861,411	64,131,850
Transport volumes (Dth)	141,600,080	126,927,565	77,393,775	77,433,266	73,730,017
Power Generation Segment:					
MWh Sold [(g)]	1,589,428	1,868,513	1,796,242	1,760,160	1,564,789
MWh Purchased	69,377	85,993	68,744	38,237	5,481
Mining Segment:					
Tons of coal sold (thousands of tons)	4,183	3,817	4,140	4,317	4,285
Coal reserves (thousands of tons)	194,909	199,905	203,849	208,231	212,595

(a) The increase in 2016 includes the debt associated with the SourceGas acquisition (see Note 6 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K).

(b) On November 1, 2017, we made the decision to divest our oil and gas business. 2017 includes an after-tax fair value impairment on held-for-sale assets of $13 million. 2016 includes non-cash after-tax impairment charges to crude oil and natural gas properties of $67 million. 2015 includes non-cash after-tax ceiling test impairment charges to crude oil and natural gas properties of $158 million and a non-cash after-tax equity investment impairment charge of $2.9 million (see Note 21 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K).

(c) On April 14, 2016, BHEG sold a 49.9% interest in Black Hills Colorado IPP. Net income available for common stock for 2017 and 2016 was reduced by $14 million and $9.6 million, respectively, attributable to this noncontrolling interest. 2013 includes $6.6 million after-tax expense relating to the settlement of interest rate swaps and write-off of deferred financing costs in conjunction with the prepayment of Black Hills Wyoming's project financing.

(d) 2017, 2016 and 2015 include incremental SourceGas Acquisition costs, after-tax of $2.8 million, $30 million and $6.7 million, respectively. 2016 and 2015 also include after-tax internal labor costs attributable to the SourceGas Acquisition of $9.1 million and $3.0 million that otherwise would have been charged to other segments. 2013 includes $20 million non-cash after-tax unrealized mark-to-market gains, respectively, related to certain interest rate swaps; 2013 also includes $7.6 million after-tax expense for a make-whole premium, write-off of deferred financing costs relating to the early redemption of our $250 million notes and interest expense on new debt.

(e) Discontinued operations in 2013 includes post-closing adjustments and operations relating to Enserco, sold in 2012.

(f) In 2016, we issued 1.97 million shares at an average share price of $60.95 under our ATM equity offering program. In November 2015, we issued 6.3 million shares of common stock, par value $1.00 per share at a price of $40.25.

(g) The decrease in 2017 is driven by the joint dispatch agreement Colorado Electric became a part of in 2017. See details of this agreement in Item 1. Business and Properties, Electric Utilities Segment in this Annual Report on Form 10-K.

(h) Calculated based on Income (loss) from continuing operations available for common stock.

For additional information on our business segments see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Item 7A, Quantitative and Qualitative Disclosures about Market Risk and Note 5 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

ITEMS 7 & 7A. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS AND QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are a customer-focused, growth-oriented, vertically-integrated utility company operating in the United States. We report our operations and results in the following financial segments.

Electric Utilities: Our Electric Utilities segment generates, transmits and distributes electricity to approximately 210,000 customers in South Dakota, Wyoming, Colorado and Montana. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our own distribution systems. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates.

Gas Utilities: Our Gas Utilities conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Wyoming and Nebraska subsidiaries. Our Gas Utilities transport and distribute natural gas through our network to approximately 1,042,000 natural gas customers. Additionally, we sell contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates, on an as available basis.

Our Gas Utilities also provide non-regulated services through Black Hills Energy Services. Black Hills Energy Services provides approximately 52,000 retail distribution customers in Nebraska and Wyoming with unbundled natural gas commodity offerings under the regulatory-approved Choice Gas Program. We also sell, install and service air conditioning, heating and water-heating equipment, and provide associated repair service and protection plans under various trade names. Service Guard and CAPP provide appliance repair services to approximately 63,000 and 31,000 residential customers, respectively, through Company technicians and third-party service providers, typically through on-going monthly service agreements. Tech Services serves gas transportation customers throughout our service territory by constructing and maintaining customer-owned gas infrastructure facilities, typically through one-time contracts.

Power Generation: Our Power Generation segment produces electric power from its generating plants and sells the electric capacity and energy principally to our utilities under long-term contracts.

Mining: Our Mining segment produces coal at our coal mine near Gillette, Wyoming and sells the coal primarily to on-site, mine-mouth power generation facilities.

Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation. All of our operations and assets are located within the United States. All of our non-utility business segments support our utilities. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other.

Overview: Our customer focus provides opportunities to expand our business by constructing additional rate base assets to serve our utility customers and expanding our non-regulated energy products and services to our wholesale customers.

Our Objective

Our objective is to be best-in-class relative to certain operational performance metrics, such as safety, power plant availability, electric and gas system reliability, efficiency, customer service and cost management. Our notable operational performance metrics for 2017 include:

- Our three electric utilities achieved 1st quartile reliability ranking with 67 customer minutes of outage time (SAIDI) in 2017 compared to industry averages (IEEE 2017 1st quartile is less than 97 minutes);

- Our power generation fleet achieved a forced outage factor of 5.04% for coal-fired plants, 1.42% for natural gas-fired turbines, 0.74% for natural gas-combined cycle power blocks and 0.17% for diesel plants in 2017, compared to an industry average* of 3.10%, 3.38%, 2.24% and 1.03%, respectively (*NERC GADS 2016 Data);

- Our power generation fleet availability was 89.82% for coal-fired plants, 95.70% for natural gas-fired turbines, 95.93% for natural gas-combined cycle power blocks, 99.53% for diesel-fired plants, and 94.06% for wind generation in 2017 while the industry averages** were 86.37%, 90.88%, 94.11%, 93.61 and 96.0% respectively (** NERC GADS 2016 data used for coal, natural gas-gas turbines, natural gas-combined cycles, and diesel plants; NERC GADS does not keep wind at this time; accordingly, wind average obtained from wind generation articles by manufacturer(s));

- Our safety TCIR of 1.3 compares to an industry average of 2.1[+] and our DART rate of 0.8 compares to an industry average of 1.2[+] ([+] Bureau of Labor Statistics (BLS)-all utilities of all sizes - most recent industry averages are 2016); and
- Our mine completed over five years with no MSHA reportable injuries and received an award from the State of Wyoming for eight years without a lost time incident. The mine also received the State Mine Inspector's Award for the fourth year in a row for operating as the safest small mine and received the Mine Safety and Health Administration's Certificate of Achievement for No Lost Time Incidents.

The electric utility industry is facing requirements to upgrade aging infrastructure, deploy smart grid technology and comply with new state and federal environmental regulations and renewable portfolio standards. Increased energy efficiency and smart grid technologies suppress demand in many areas of the United States. These competing considerations present challenges to energy companies' approach to balancing capital spending and obtaining satisfactory rate recovery on investments.

State regulatory commissions have lowered authorized returns and implemented other regulatory mechanisms for cost recovery due to the slow-growing economy and concerns that utility rate increases may further harm local economies. The average awarded return on equity for investor-owned utilities over the past year has been just under 10%. The average regulatory lag is less than 12 months, according to the Edison Electric Institute. Sustained low interest rates heavily influence the lower rates of return, along with actions by state commissions to moderate rate increases during a period of economic recovery.

In our gas and electric utilities' service territories, we will continue to work with regulators to ensure we meet our obligations to serve projected customer demand and to comply with environmental mandates by constructing the infrastructure necessary to provide safe, reliable energy. By maintaining our high customer service and reliability standards in a cost-efficient manner, our goal is to secure appropriate rate recovery that provides fair economic returns on our utility investments.

According to the U.S. Energy Information Administration, approximately 30% of electricity generated in the United States is from coal-fired power plants. It will take significant time and expense before this generation can be replaced with alternative technologies. As a result, coal-fired resources will remain a necessary component of the nation's electric supply for the foreseeable future. The regulatory climate in recent years, combined with the EPA's regulations, have limited construction of new conventional coal-fired power plants, but, if technologies such as carbon capture and sequestration become more proven and less expensive, they could provide for the long-term economic use of coal. We have investigated and will continue to investigate the possible deployment of these technologies at our mine site in Wyoming.

Key Elements of our Business Strategy

Efficiently plan, construct and operate utility systems that provide safe, reliable and affordable energy to our customers and competitive, sustained returns for our shareholders. The Company is an electric and natural gas utility serving approximately 1.25 million utility customers in more than 800 communities in eight Rocky Mountain and Midwestern states, with a service territory that spans nearly 1,600 miles, reaching from Cody, Wyoming to Blytheville, Arkansas. Our natural gas utility business owns and operates a 45,000-mile natural gas transmission and distribution pipeline system and our electric utility business owns and operates 941 megawatts of generation capacity and 8,800 miles of transmission and distribution lines. The company's primary growth strategy is to invest in these utility systems to ensure the continued delivery of safe, reliable and affordable energy for customers and competitive, sustained returns for our shareholders.

Maintain a safe and reliable gas distribution system. We rigorously comply with all applicable federal, state and local regulations and strive to consistently meet industry best practice standards. Preventing natural gas losses from our gas delivery systems is of the utmost importance to ensure public and employee safety and to protect the environment. We construct, maintain and update our gas delivery systems with state of the art materials and products and continuously monitor their integrity. System leaks are repaired as soon as possible while ensuring the safety of the public and our employees. We have removed all cast and wrought iron from our natural gas transmission and distribution systems and they contain very minimal quantities of bare steel pipelines. Many of our gas utilities are authorized to use system safety, integrity and replacement cost recovery mechanisms that provide for customer rate adjustments which reflect the cost incurred in repairing and replacing the gas delivery systems.

Efficiently plan, construct and operate rate base power generation facilities to serve our electric utilities. Our company began as a vertically-integrated electric utility. This business model remains a core strength and strategy today as we invest in and operate efficient power generation resources to cost-effectively supply electricity to our customers. We strive to provide power at reasonable rates to our customers and earn competitive returns for our investors.

Our power production strategy focuses on low-cost construction and operation of our generating facilities. Our low power production costs result from a variety of factors including low fuel costs, efficiency in converting fuel into energy, low per unit operation and maintenance costs, and high levels of power plant availability. We leverage our mine-mouth coal-fired generating capacity to eliminate fuel transportation costs that often represent the largest component of the delivered cost of coal for many other utilities. Additionally, we operate our plants with high levels of availability as compared to industry benchmarks.

Rate-based generation assets offer several advantages for customers and shareholders, including:

- When generating assets are included in the utility rate base and reviewed and approved by government authorities, customer rates are more stable and predictable, and typically less expensive in the long run; especially when compared to power otherwise purchased from the open market through wholesale contracts that are periodically re-priced to reflect current and varying market conditions;

- Regulators participate in a planning process where long-term investments are designed to match long-term energy demand;

- The lower risk profile of rate-based generation assets contributes to stronger credit ratings which, in turn, can benefit both consumers and investors by lowering the cost of capital; and

- Investors are provided a long-term, reasonable, stable return on their investment.

Proactively integrate alternative and renewable energy into our utility energy supply while mitigating customer rate impacts. The energy and utility industries face uncertainty and potential investment opportunities related to existing and potential legislation and regulation intended to reduce GHG emissions and increase the use of renewable and other alternative energy sources. To date, many states have enacted, and others are considering, mandatory renewable energy standards, requiring utilities to meet certain thresholds of renewable energy generation. Some states have either enacted or are considering legislation setting GHG emissions reduction targets. Federal legislation for both renewable energy standards and GHG emission reductions has been considered and may be implemented in the future.

Mandates for the use of renewable energy or the reduction of GHG emissions will likely provide investment opportunities for our electric utilities, gas utilities and power generation business. These mandates will also likely increase prices for electricity and/or natural gas for our utility customers. As a regulated utility we are responsible for providing safe, reliable and affordable sources of energy to our customers. Accordingly, we employ a customer-centered strategy for complying with renewable energy standards and GHG emission regulations that balance our customers' rate concerns with environmental considerations and administrative and legislative mandates. We attempt to strike this balance by prudently and proactively incorporating renewable energy into our resource supply, while seeking to minimize the magnitude and frequency of rate increases for our utility customers.

Build and maintain strong relationships with wholesale power customers of our utilities and our power generation business. We strive to build strong relationships with other utilities, municipalities and wholesale customers. We believe we will continue to be a primary provider of electricity to wholesale utility customers, who will continue to need products such as capacity and energy to reliably serve their customers. By providing these products under long-term contracts, we help our customers meet their energy needs. We also earn more stable revenues and greater returns for shareholders over the long term than we would by selling energy into more volatile energy spot markets. In addition, relationships that we have established with wholesale power customers have developed into other opportunities. MEAN, MDU and the City of Gillette, Wyoming were wholesale power customers that are now joint owners in two of our power plants, Wygen I and Wygen III, reducing risk and providing steady revenues.

Vertically integrate businesses that are supportive of our electric and natural gas utility businesses. While our primary focus is on growing our core utilities, we selectively invest in vertically integrated businesses that provide cost effective and efficient fuel and energy to our utilities. We currently own and operate a coal mine and power generation assets that are vertically integrated into and supportive of our electric utilities. These operations are located at our utility generating complexes and are physically integrated into our electric utility operations.

Our surface coal mine is located immediately adjacent to our Gillette energy complex in northeastern Wyoming, where all five of our coal-fired power plants are located. We operate and own 100% or own a majority interest in four of the five plants; we have a 20% interest in the fifth plant, which is operated by a third party. The coal mine provides low-sulfur coal directly to these power plants via a conveyor belt system, minimizing coal transportation costs. On average, the coal can be delivered to

the adjacent power plants at substantially less than $1.00 per MMBtu, providing very cost competitive fuel to our power plants when compared to other coal-fired and gas-fired power plants.

We have a power generation segment that employs professionals with significant expertise in planning and building power generation facilities, having constructed 19 coal-fired, gas-fired and renewable generation projects since 1995 with aggregate project costs in excess of $2 billion. This group also provides shared services to our electric utilities' generation facilities, resulting in efficient management of all of the company's generation assets. In certain states, our electric utilities are required to competitively bid for generation resources needed to serve customers. Generally, our power generation segment submits bids in response to those competitive solicitations. Our generation segment can often realize competitive advantages provided by prior construction expertise, fuel supply advantages and by co-locating new plants at existing sites, reducing infrastructure and operating costs.

Expand utility operations through selective acquisitions of electric and gas utilities. The electric and natural gas utility industries have consolidated significantly over the past decade and continue to consolidate. We have successfully acquired and integrated numerous utility systems since 2005, including two large, transformational acquisitions - the Aquila utility properties in 2008 and SourceGas in 2016. Through these acquisitions, we developed a scalable platform that simplifies the rapid integration of acquired utilities, providing significant benefits to both customers and shareholders. The company targets small to large utilities, including municipal and private utility systems, located primarily in geographies that are near to or contiguous with our existing utility service territories and provide long-term value for both customers and shareholders. In the near-term, we do not expect to pursue large utility acquisitions, particularly given the high valuation multiples realized in recent utility transactions. We will continue to pursue the purchase of small utility systems within or near our geographic footprint, which can be quickly and efficiently integrated into our existing utilities.

Grow our dividend. We are extremely proud of our track record for annual dividend increases for shareholders. In January 2018, we declared a dividend of $0.475 per share, equivalent to an annual dividend rate of $1.90 per share. This annual equivalent rate represents an increase of 5% over the total 2017 dividend of $1.81 per share and the 48th consecutive annual dividend increase. We intend to continue our record of annual dividend increases with a targeted dividend payout ratio of 50% to 60%. This target payout ratio provides the flexibility for greater increases to our dividend during periods of relatively slow earnings growth.

Maintain an investment grade credit rating and ready access to debt and equity capital markets. We require access to the capital markets to fund our planned capital investments or acquire strategic assets that support prudent and earnings accretive business growth. We have demonstrated our ability to cost-effectively access the debt and equity markets, while maintaining our investment-grade issuer credit rating.

Prospective Information

We expect to generate long-term growth through the expansion of integrated utilities and supporting operations. Sustained growth requires continued capital deployment. Our integrated energy portfolio, focused primarily on regulated utilities provides growth opportunities, yet avoids concentrating business risk. We expect much of our growth in the next few years will come from capital deployment opportunities at our utilities and continued focus on improving efficiencies and reducing costs. Although dependent on market conditions, we are confident in our ability to obtain additional financing, as necessary, to continue our growth plans. We remain focused on prudently managing our operations and maintaining our overall liquidity to meet our operating, capital and financing needs, as well as executing our long-term strategic plan.

Electric Utilities

In September 2017, the Mountain West Transmission Group, which includes all of Black Hills electric utilities and seven other electricity providers, formally expressed an interest in joining the Southwest Power Pool (SPP) regional transmission organization. If membership is deemed beneficial, filings with FERC and state public utility commissions would likely occur in mid-2018 with integration into SPP in late 2019.

On January 17, 2017, Colorado Electric received approval from the CPUC on a settlement agreement for its electric resource plan which provides for the addition of 60 megawatts of renewable energy to be in service by 2019. The resource plan was filed on June 3, 2016, to meet requirements under the Colorado Renewable Energy Standard. In the second quarter of 2017, Colorado Electric issued a request for proposals to acquire renewable energy resources to comply with the Colorado Renewable

Energy Standard and presented the results to the CPUC on February 9, 2018. We expect a final decision from the CPUC in the second quarter of 2018 approving, conditioning, modifying or rejecting Colorado Electric's recommended portfolio.

Retail MWhs sold increased in 2017 primarily due to industrial load growth at Wyoming Electric, which set a new all-time summer peak load of 249 MW in July 2017.

Construction was completed on the 144 mile transmission line connecting the Teckla Substation in northeast Wyoming to the Lange Substation near Rapid City, South Dakota. The first segment of this project connecting Teckla to Osage, WY was placed in service on August 31, 2016. The second segment connecting Osage to Lange was placed in service on May 30, 2017.

Gas Utilities

In 2017, we filed requests for rate reviews in Arkansas, Wyoming and Colorado, driven by investments made on recently acquired utilities to replace, upgrade and maintain natural gas transmission and distribution pipelines. See 2017 Results of Operations and Note 13 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more information.

Our Gas Utilities invested in our gas distribution network and related technology such as advanced metering infrastructure and mobile data terminals. We continually monitor our investments and costs of operations in all states to determine the appropriateness of additional rate reviews or other rate filings. As part of our growth strategy, we continue to look for opportunities to purchase municipal and privately-owned gas infrastructure and distribution systems within or nearby our service territories.

Mining

Production from the Mining segment primarily serves mine-mouth generation plants and select regional customers with long-term fuel needs. Total annual production was approximately 4.2 million tons for 2017. Mining operations moved to an area with higher overburden ratios in 2017, which increased mining costs. However, lower fuel costs and efficiencies in executing our mine plan partially offset these costs. Our stripping ratio at December 31, 2017 was 2.16 and we expect stripping ratios in 2018 to be approximately 2.15 as the areas planned for mining contain comparable overburden.

Our strategy is to sell the majority of our coal production to on-site, mine-mouth generation facilities under long-term supply contracts. Approximately one-half of our coal is sold under cost-plus contracts with affiliates. Historically our limited off-site sales have been to consumers within a close proximity to our mine, including off-site sales contracts served by truck. We continue to pursue new opportunities to market our coal despite limitations inherent to transporting our lower-heat content coal.

Corporate and Other

We utilized favorable short-term borrowings from our CP program to pay down $100 million on a Corporate term loan due in 2019 with principal payments of $50 million paid in May and an additional $50 million paid in July. In August 2017, we renewed the ATM equity offering program, which reset the size of the program to an aggregate value of up to $300 million. See additional detail in the 2017 Corporate highlights.

Results of Operations

Executive Summary and Overview

	For the Years Ended December 31,				
	2017	Variance	2016	Variance	2015
	(in thousands)				
Revenue					
Revenue	$ 1,810,447	$ 143,412	$ 1,667,035	$ 280,036	$ 1,386,999
Intercompany eliminations	(130,181)	(2,062)	(128,119)	(2,442)	(125,677)
	$ 1,680,266	$ 141,350	$ 1,538,916	$ 277,594	$ 1,261,322
Income from continuing operations available for common stock [a]					
Electric Utilities	$ 110,082	$ 24,255	$ 85,827	$ 8,248	$ 77,579
Gas Utilities [b]	65,795	6,171	59,624	20,318	39,306
Power Generation [c]	46,479	20,549	25,930	(6,720)	32,650
Mining	14,386	4,333	10,053	(1,817)	11,870
	236,742	55,308	181,434	20,029	161,405
Corporate and Other [a] [b] [d] [e]	(42,609)	1,693	(44,302)	(24,445)	(19,857)
Income from continuing operations	194,133	57,001	137,132	(4,416)	141,548
(Loss) from discontinued operations, net of tax [f] [g]	(17,099)	47,063	(64,162)	109,497	(173,659)
Net income (loss) available for common stock	$ 177,034	$ 104,064	$ 72,970	$ 105,081	$ (32,111)

(a) Income from continuing operations available for common stock for 2017 includes a net tax benefit of $7.6 million from the revaluation of deferred tax balances due to a decrease in the statutory Federal income tax rate resulting from the TCJA. This benefit's impact to our operating segments and Corporate and Other was: Electric Utilities - $23 million tax benefit; Gas Utilities - $6.8 million tax expense; Power Generation - $24 million tax benefit; Mining - $2.7 million tax benefit; Corporate and Other - $35 million tax expense which includes $28 million of tax expense from the revaluation of Corporate deferred taxes, as well as an additional $7.0 million of tax expense from the revaluation of deferred taxes that were originally recorded to AOCI.

(b) Income from continuing operations available for common stock for 2017 includes a $4.1 million tax benefit from a true-up to the filed 2016 SourceGas tax returns relating to the SourceGas Acquisition.

(c) On April 14, 2016, BHEG sold a 49.9% interest in Black Hills Colorado IPP. Income from continuing operations available for common stock for 2017 and 2016 was reduced by $14 million and $9.6 million, respectively, attributable to this noncontrolling interest.

(d) Income from continuing operations available for common stock for 2017, 2016 and 2015 include incremental SourceGas Acquisition costs, after-tax of $2.8 million, $30 million and $6.7 million, respectively and after-tax internal labor costs attributable to the SourceGas Acquisition of $0.5 million, $9.1 million and $3.0 million, respectively that otherwise would have been charged to other business segments.

(e) Income from continuing operations available for common stock for 2016 included tax benefits of approximately $4.4 million as a result of the re-measurement of the liability for uncertain tax positions predicated on an agreement reached with IRS Appeals in early 2016.

(f) Loss from discontinued operations in 2017, 2016 and 2015 included non-cash after-tax impairments of crude oil and natural gas properties of $13 million, $67 million and $160 million, respectively. See Note 21 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

(g) Loss from discontinued operations in 2016 included a tax benefit of approximately $5.8 million recognized from additional percentage depletion deductions that are being claimed with respect to our oil and gas properties involving prior years.

The following business group and segment information does not include intercompany eliminations and all amounts are presented on a pre-tax basis unless otherwise indicated. Per share information references diluted shares unless otherwise noted.

2017 Compared to 2016

Income from continuing operations available for common stock was $194 million, or $3.52 per diluted share in 2017 compared to $137 million, or $2.57 per diluted share in 2016. The variance to the prior year was primarily due to:

- Corporate and Other, excluding tax reform impacts, decreased by approximately $37 million compared to the same period in the prior year driven primarily by a $27 million reduction of after-tax external acquisition and transition costs, a reduction of approximately $8.6 million of internal labor attributed to the SourceGas Acquisition and lower reallocated discontinued operation expenses of approximately $2.9 million, partially offset by a $4.4 million tax benefit in 2016;
- Gas Utilities' earnings, excluding tax reform impacts, increased approximately $13 million, with a full year of earnings from our acquired SourceGas utilities compared to approximately 10.5 months in 2016, and a $4.1 million tax benefit recognized in 2017;
- We recorded a net tax benefit of approximately $8 million as a result of the revaluation of deferred tax balances due to the decrease in the statutory Federal income tax rate as a result of the TCJA. This benefit's impact to our operating segments and Corporate and Other was:
    - Electric Utilities - $23 million tax benefit
    - Gas Utilities - $6.8 million tax expense
    - Power Generation - $24 million tax benefit
    - Mining - $2.7 million tax benefit
    - Corporate and Other - $35 million tax expense consisting of $28 million of tax expense from the revaluation of Corporate deferred tax balances and $7 million of tax expense from the revaluation of deferred taxes that were originally recorded to AOCI.
- Electric Utilities' earnings, excluding tax reform impacts, were comparable to the prior year reflecting an increase from returns on prior year generation investments, offset by higher employee costs and higher generation maintenance expenses;
- Earnings at our Power Generation segment, excluding tax reform impacts, decreased $3.5 million primarily due to an increase in net income attributable to noncontrolling interests, reflecting a full year in 2017 compared to approximately 8.5 months in 2016; and
- Earnings at our Mining segment, excluding tax reform impacts, increased approximately $1.6 million due to an increase in tons sold as a result of an extended outage in the prior year;.

Net income (loss) available for common stock was $177 million, or $3.21 per diluted share in 2017, compared to $73 million, or $1.37 per share in 2016. BHEP has been reclassified and is included in discontinued operations. (Loss) from discontinued operations was $(17) million or $(0.31) per diluted share in 2017 compared to $(64) million or $(1.20) per diluted share in 2016. Discontinued operations in 2017 included an after-tax fair value impairment of assets of approximately $13 million compared to 2016 which included non-cash after-tax oil and gas property impairment charges of $67 million. Also included in 2016 discontinued operations was a $5.8 million tax benefit recognized from additional percentage depletion deductions that were claimed with respect to our oil and gas properties involving prior years.

2017 Overview of Business Segments and Corporate Activity

Electric Utilities

- In our Electric Utilities service territories, winter weather was mostly comparable to the prior year and the summer was milder in 2017 compared to the prior year. Heating degree days in 2017 were 11% lower than normal compared to 13% lower than normal in 2016. Cooling degree days for the full year of 2017 were 14% higher than normal compared to 26% higher than normal in 2016.

- On January 17, 2017, Colorado Electric received approval from the CPUC on a settlement agreement for its electric resource plan which provides for the addition of 60 megawatts of renewable energy to be in service by 2019. The resource plan was filed June 3, 2016, to meet requirements under the Colorado Renewable Energy Standard. In the second quarter of 2017, Colorado Electric issued a request for proposals to acquire renewable energy resources to comply with the Colorado Renewable Energy Standard and presented the results to the CPUC on February 9, 2018. We expect a final decision from the CPUC in the second quarter of 2018 approving, conditioning, modifying or rejecting Colorado Electric's recommended portfolio.

- On January 9, 2017, we filed an application with the CPUC for rehearing, reargument or reconsideration of the Commission's December 19, 2016 decision to increase annual revenue by $1.2 million. This application was denied by the CPUC on June 9, 2017. We subsequently filed an appeal of this decision with Denver County District Court on July 10, 2017. On October 4, 2017, the Company filed an Opening Brief. The Company filed a Reply Brief on November 22, 2017. The matter is pending.

- Construction was completed on the 144 mile transmission line connecting the Teckla Substation in northeast Wyoming to the Lange Substation near Rapid City, South Dakota. The first segment of this project connecting Teckla to Osage, WY was placed in service on August 31, 2016. The second segment connecting Osage to Lange was placed in service on May 30, 2017.

- On July 19, 2017, Wyoming Electric set a new summer load peak of 249 MW, exceeding the previous summer peak of 236 MW set in July 2016.

Gas Utilities

- Our service territories reported comparable year-over-year winter weather as measured by heating degree days compared to the 30-year average. Combined heating degree days for the full year in 2017 were 10% less than normal compared to 11% less than normal in the same period in 2016.

  The Gas Utilities also experienced cooler summer temperatures and higher precipitation levels during the third quarter of 2017 compared to the same period in 2016, which reduced the irrigation load delivered to agricultural customers, primarily in our Nebraska service territory.

- On December 15, 2017, Arkansas Gas filed a rate review application with the APSC requesting an annual increase in revenue of approximately $30 million. The annual increase is based on a return on equity of 10.2% and a capital structure of 45.3% debt and 54.7% equity. This rate review was driven by approximately $160 million of investments made since 2016 to replace, upgrade and maintain Arkansas Gas' approximately 5,500 miles of natural gas transmission and distribution pipelines. If approved, new rates would be implemented in the fourth quarter of 2018. We are reviewing the impact of tax reform as it applies to the filing.

- On November 17, 2017, Wyoming Gas requested rate review application with the WPSC requesting an annual increase in revenue of approximately $1.4 million for natural gas system improvements supporting its Northwest Wyoming customers. The annual increase is based on a return on equity of 10.2% and a capital structure of 46% debt and 54% equity. This rate review was driven by approximately $6 million of investments made since 2015 to replace, upgrade and maintain approximately 620 miles of natural gas transmission and distribution pipelines. If approved, new rates would be implemented in mid-2018. We are reviewing the impact of tax reform as it applies to the filing.

- On October 3, 2017, RMNG filed a rate review application with the CPUC requesting an annual increase in revenue of $2.2 million and an extension of SSIR to recover costs from 2018 through 2022. The annual increase is based on a return on equity of 12.25% and a capital structure of 53.37% debt and 46.63% equity. This rate review was driven by the impending expiration of the SSIR on May 31, 2018; this application requests a continuation of the SSIR through 2022. We are reviewing the impact of tax reform as it applies to the filing.

Corporate Activities

- On August 4, 2017, we renewed the ATM equity offering program, which reset the size of the program to an aggregate value of up to $300 million. The renewed program, which allows us to sell shares of our common stock, is the same as the prior year program other than the aggregate value increased from $200 million to $300 million. We did not issue any common shares during the twelve months ended December 31, 2017.

- On December 12, 2017, Moody's affirmed Black Hills' credit rating at Baa2 with a Stable outlook.

- On October 4, 2017, Fitch affirmed Black Hills' credit rating at BBB+ rating and maintained a Stable outlook.

- On July 21, 2017, S&P affirmed Black Hills' credit rating at BBB rating and maintained a Stable outlook.

Discontinued Operations

- On November 1, 2017, the BHC board of directors approved a complete divestiture of our Oil and Gas segment. As of February 23, 2018, we have either closed transactions or signed contracts to sell more than 90 percent of our oil and gas properties. We have executed agreements to sell all our operated properties and have only non-operated assets with minimal value left to divest. We plan to conclude the sale of all of our remaining assets by mid-year 2018. The results of our Oil and Gas segment are reflected in discontinued operations, other than certain general and administrative and interest costs which have been reallocated to our other segments. Oil and Gas segment assets and liabilities are classified as held for sale.

2016 Compared to 2015

Income from continuing operations available for common stock was $137 million, or $2.57 per diluted share in 2016, compared to $142 million, or $3.12 per diluted share in 2015. The variance to the prior year was primarily due to:

- higher earnings at our Electric Utilities of $8.2 million driven primarily by returns on generation investments;
- higher earnings at our Gas Utilities of approximately $20 million, which include earnings of $15 million from our acquired SourceGas utilities since the acquisition date of February 12, 2016;
- tax benefits of approximately $5.1 million from the re-measurement of uncertain tax positions' liability predicated on an agreement reached with IRS Appeals;
- Increased corporate expenses which included approximately $30 million of after-tax incremental acquisition and transition costs related to SourceGas;
- Lower earnings at our Power Generation segment due to net income attributable to noncontrolling interests of $9.6 million;
- Lower earnings at our Mining segment due to an extended 2016 outage at the Wyodak plant.

Net income (loss) available for common stock was $73 million, or $1.37 per diluted share in 2016, compared to $(32) million or $(0.71) per diluted share in 2015. BHEP has been reclassified and is included in discontinued operations. (Loss) from discontinued operations was $(64) million or $(1.20) per diluted share in 2016 compared to $(174) million or $(3.83) per diluted share. Discontinued operations in 2016 included non-cash after-tax oil and gas property impairment charges of $67 million compared to non-cash after-tax ceiling test impairments of our oil and gas properties of $158 million in 2015.

2016 Overview of Business Segments and Corporate Activity

Electric Utilities

- In our Electric Utilities service territories, mild winter weather in 2016 partially offset a hotter than normal summer. Heating degree days were 2% lower than the prior year and 13% lower than normal. Offsetting this decrease was weather related demand during the peak summer months. Cooling degree days for the full year of 2016 were 9% higher than the same period in the prior year and 26% higher than normal.

- On December 19, 2016, Colorado Electric received approval from the CPUC to increase its annual revenues by $1.2 million to recover investments in a $63 million, 40 MW natural gas-fired combustion turbine. This turbine was completed in the fourth quarter of 2016, achieving commercial operation on December 29, 2016. The approval allowed a return on rate base of 6.02% for this turbine, with a 9.37% return on equity and a capital structure of 67.34% debt and 32.66% equity. Whereas, an authorized return on rate base of 7.4% was received for the remaining system investments, with a return on equity of 9.37% and an approved capital structure of 47.6% debt and 52.4% equity.
  Construction riders related to the project increased gross margins by approximately $5.1 million for the year ended December 31, 2016.

- On November 8, 2016, Colorado Electric completed the purchase of Peak View, a $109 million, 60 MW Wind Project located near Colorado Electric's Busch Ranch Wind Farm. Peak View achieved commercial operation on November 7, 2016 and was purchased through progress payments throughout 2016 under a commission approved third-party build- transfer and settlement agreement. This renewable energy project was originally submitted in response to Colorado Electric's all-source generation request on May 5, 2014. The Commission's settlement agreement provides for recovery of the costs of the project through Colorado Electric's Electric Cost Adjustments, Renewable Energy Standard Surcharge and Transmission Cost Adjustment for 10 years, after which Colorado Electric can propose base rate recovery.

- During the first quarter of 2016, South Dakota Electric commenced construction of the $54 million, 230-kV, 144 mile-long transmission line that connects the Teckla Substation in northeast Wyoming to the Lange Substation near Rapid City, South Dakota. Recovery is concurrent through the FERC transmission tariff. The first segment of this project connecting Teckla to Osage, WY was placed in service on August 31, 2016. The second segment connecting Osage to Lange was placed in service in May of 2017.

Gas Utilities

- On February 12, 2016, Black Hills Utility Holdings acquired SourceGas Holdings, LLC pursuant to the purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in long-term debt at closing. See additional information below under Corporate activities.

- Gas Utilities were unfavorably impacted by milder weather in 2016 compared to 2015. Our service territories reported warmer than normal winter weather as measured by heating degree days, compared to the 30-year average, and compared to 2015. Heating degree days for the full year in 2016 were 11% less than normal and 1% less than the same period in 2015.

Power Generation

- Black Hills Colorado IPP owns and operates a 200 MW, combined cycle natural gas generating facility located in Pueblo, Colorado. On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million. FERC approval of the sale was received on March 29, 2016. Proceeds from the sale were used to pay down short-term debt. Black Hills Electric Generation continues to be the majority owner and operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric.

Corporate Activities

- In 2016, we implemented a $750 million, unsecured CP Program that is backstopped by our Revolving Credit Facility, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extended the term through August 9, 2021 and we entered into a new $500 million term loan expiring August 9, 2019. We completed the permanent financing for the SourceGas Acquisition. In addition to the net proceeds of $536 million from our November 2015 equity issuances, we completed the Acquisition financing with $546 million of net proceeds from our January 2016 debt offering. We also refinanced the long-term debt assumed with the SourceGas Acquisition primarily through $693 million of net proceeds from our August 19, 2016 debt offerings. In addition to our debt refinancings, we issued 1.97 million shares of common stock for approximately $119 million through our ATM equity offering program, and sold a 49.9% noncontrolling interest in Black Hills Colorado IPP for $216 million. On June 7, 2016, we issued a $29 million, declining balance five-year term loan maturing June 7, 2021, to finance the early termination of a gas supply agreement. See Footnotes 6 and 7 of the Notes to the Consolidated Financial Statements included in this Annual Report on Form 10-K for additional information relating to our long-term debt and notes payable.

- On December 9, 2016, Moody’s issued a Baa2 rating with a Stable outlook, which reflects the higher debt leverage resulting from the incremental debt used to fund the SourceGas Acquisition.

- During the first quarter of 2016, we reached an agreement in principle with IRS Appeals with respect to our liability for unrecognized tax benefits attributable to the like-kind exchange effectuated in connection with the 2008 IPP Transaction and the 2008 Aquila Transaction. This agreement resulted in a tax benefit of approximately $5.1 million in the first quarter of 2016. See Note 15 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for additional details on this agreement.

- On February 12, 2016, Black Hills Utility Holdings acquired SourceGas Holdings, LLC pursuant to the purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in long-term debt at closing.

- On February 12, 2016, S&P affirmed the BHC credit rating of BBB and maintained a stable outlook after our acquisition of SourceGas, reflecting their expectation that management will continue to focus on the core utility operations while maintaining an excellent business risk profile following the acquisition.

- On February 12, 2016, Fitch affirmed the BHC credit rating of BBB+ and maintained a negative outlook after our acquisition of SourceGas, which reflects the initial increased leverage associated with the SourceGas Acquisition.

- On January 20, 2016, we executed a 10-year, $150 million notional, forward starting pay fixed interest rate swap at an all-in interest rate of 2.09%, and on October 2, 2015, we executed a 10-year, $250 million notional forward starting pay fixed interest rate swap at an all-in rate of 2.29%, to hedge the risks of interest rate movement between the hedge dates and pricing date for long-term debt refinancings occurring in August 2016. On August 19, 2016, we settled and terminated these interest rate swaps for a loss of $29 million. The loss recorded in AOCI is being amortized over the 10-year life of the associated debt.

Operating Results

A discussion of operating results from our business segments follows.

All amounts are presented on a pre-tax basis unless otherwise indicated.

Non-GAAP Financial Measure

The following discussion includes financial information prepared in accordance with GAAP, as well as another financial measure, gross margin, that is considered a “non-GAAP financial measure.” Generally, a non-GAAP financial measure is a numerical measure of a company’s financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP. Gross margin (revenue less cost of sales) is a non-GAAP financial measure due to the exclusion of depreciation from the measure. The presentation of gross margin is intended to supplement investors’ understanding of our operating performance.

In our Management Discussion and Analysis of Results of Operations, gross margin for our Electric Utilities is calculated as operating revenue less cost of fuel, purchased power and cost of gas sold. Gross margin for our Gas Utilities is calculated as operating revenues less cost of gas sold. Our gross margin is impacted by the fluctuations in power purchases and natural gas and other fuel supply costs. However, while these fluctuating costs impact gross margin as a percentage of revenue, they only impact total gross margin if the costs cannot be passed through to our customers.

Our gross margin measure may not be comparable to other companies’ gross margin measure. Furthermore, this measure is not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

Electric Utilities

Operating results for the years ended December 31 for the Electric Utilities were as follows (in thousands):

	2017	Variance	2016	Variance	2015
Revenue	$ 704,650	$ 27,369	$ 677,281	$ (2,562)	$ 679,843
Total fuel and purchased power	268,405	7,056	261,349	(8,060)	269,409
Gross margin	436,245	20,313	415,932	5,498	410,434
Operations and maintenance	172,307	14,173	158,134	(2,790)	160,924
Depreciation and amortization	93,315	8,670	84,645	3,716	80,929
Total operating expenses	265,622	22,843	242,779	926	241,853
Operating income	170,623	(2,530)	173,153	4,572	168,581
Interest expense, net	(52,274)	(1,983)	(50,291)	754	(51,045)
Other income (expense), net	1,730	(1,463)	3,193	1,977	1,216
Income tax expense	(9,997)	30,231	(40,228)	945	(41,173)
Net income (loss) available for common stock	$ 110,082	$ 24,255	$ 85,827	$ 8,248	$ 77,579

	2017	2016	2015
Regulated power plant fleet availability:			
Coal-fired plants [a] [b] [c]	88.9%	90.2%	91.5%
Natural gas fired plants and Other plants	96.1%	95.1%	95.4%
Wind [d]	93.3%	79.3%	99.3%
Total availability	93.6%	93.5%	94.0%
Wind capacity factor	36.7%	36.6%	32.4%

(a) 2017 reflects planned outages at Neil Simpson II, Wyodak, and Wygen II.
(b) 2016 reflects a planned outage at Wygen III, an extended planned outage at Wyodak and an unplanned outage at Neil Simpson II.
(c) 2015 reflects planned outages at Neil Simpson II, Wygen II and Wygen III.
(d) 2017 and 2016 were lower due to the addition of Peak View Wind Project with ownership transfer in November, 2016.

2017 Compared to 2016

Gross margin increased over the prior year primarily reflecting a $7.8 million return on investment from the Peak View Wind Project, a $7.4 million increase in rider revenues primarily related to transmission investment recovery, and a $2.1 million increase in commercial and industrial margins driven by increased demand largely associated with data centers in Cheyenne, Wyoming. A variety of smaller items contribute to the remainder of the net increase.

Operations and maintenance increased primarily due to $4.8 million of higher employee costs as a result of prior year integration activities and transition expenses charged to Corporate and Other, $2.6 million of higher generation outage expenses, $1.9 million of higher property taxes with an increased asset base, and $1.7 million of higher operating expenses from the Peak View Wind Project and the 40-megawatt gas turbine at the Pueblo Airport Generating Station. An additional $1.3 million of indirect corporate costs are included at the electric utilities; these costs were previously charged to our Oil and Gas segment, now reported as discontinued operations.

Depreciation and amortization increased primarily due to a higher asset base driven partially by the addition of the Peak View Wind Project and the 40-megawatt gas turbine at the Pueblo Airport Generating Station.

Interest expense, net increased primarily due to higher intercompany debt resulting from additional investments as compared to the prior year.

Other (expense) income, net decreased due to reduced AFUDC with lower capital spend.

Income tax benefit (expense): The effective tax rate was lower in 2017 primarily due to a $23 million benefit resulting from revaluation of net deferred tax liabilities in accordance with ASC 740 and the enactment of the TCJA on December 22, 2017. This benefit was primarily related to the revaluation of net operating losses and other tax basis items not included in the ratemaking construct. Production tax credits associated with the Peak View Wind Project increased by $4.0 million reflecting a full year of production tax credits compared to two months in 2016. The prior year included a $1.3 million benefit related to the flow-through treatment of a treasury grant related to the Busch Ranch Wind Project.

2016 Compared to 2015

Gross margin increased over the prior year reflecting increased rider margins of $4.9 million driven primarily by our construction and TCA riders, an increase of $2.4 million in commercial and industrial margins driven by increased demand, a $1.5 million return on investment from the Peak View Wind Project, and a $1.4 million increase in residential margins driven by favorable weather. Offsetting these increases was a $2.1 million prior-year benefit as a result of a one-time settlement with the Colorado Public Utilities Commission on our renewable energy standard adjustment related to the Busch Ranch wind farm, a prior-year increase in return on invested capital of $1.2 million from South Dakota Electric’s rate case, and a $1.3 million decrease due to third-party billing true-ups relating to the current and prior years.

Operations and maintenance decreased primarily as a result of approximately $5.8 million lower employee costs primarily driven by a change in expense allocations impacting the electric utilities as a result of integrating the acquired SourceGas utilities. This decrease is partially offset by higher operating costs from the Peak View Wind Project, which commenced commercial operation in November 2016, and increased vegetation management costs.

Depreciation and amortization increased primarily due to a higher asset base driven partially by the addition of Peak View Wind Project.

Interest expense, net decreased primarily due to higher AFUDC interest income driven by construction in process as compared to prior year.

Other (expense) income, net increased primarily due to higher AFUDC equity in the current period compared to prior year.

Income tax benefit (expense): The effective tax rate was lower than prior year primarily due to the accelerated recognition of benefits associated with certain tax incentives.

Gas Utilities

Operating results for the years ended December 31 for the Gas Utilities were as follows (in thousands):

	2017	Variance	2016	Variance	2015
Revenue:					
Natural gas - regulated	$ 865,831	$ 96,749	$ 769,082	$ 249,084	$ 519,998
Other - non-regulated	81,799	12,538	69,261	37,959	31,302
Total revenue	947,630	109,287	838,343	287,043	551,300
Cost of natural gas sold:					
Natural gas - regulated	381,259	65,641	315,618	31,985	283,633
Other - non-regulated	28,344	(8,203)	36,547	20,535	16,012
Total cost of natural gas sold	409,603	57,438	352,165	52,520	299,645
Gross margin:					
Natural gas - regulated	484,572	31,108	453,464	217,099	236,365
Other - non-regulated	53,455	20,741	32,714	17,424	15,290
Total gross margin	538,027	51,849	486,178	234,523	251,655
Operations and maintenance	269,190	23,364	245,826	105,103	140,723
Depreciation and amortization	83,732	5,397	78,335	46,009	32,326
Total operating expenses	352,922	28,761	324,161	151,112	173,049
Operating income	185,105	23,088	162,017	83,411	78,606
Interest expense, net	(78,575)	(3,562)	(75,013)	(57,702)	(17,311)
Other income (expense), net	(829)	(1,013)	184	(131)	315
Income tax expense	(39,799)	(12,337)	(27,462)	(5,158)	(22,304)
Net income (loss)	65,902	6,176	59,726	20,420	39,306
Net income attributable to noncontrolling interest	(107)	(5)	(102)	(102)	—
Net income (loss) available for common stock	$ 65,795	$ 6,171	$ 59,624	$ 20,318	$ 39,306

2017 Compared to 2016

Gross margin increased primarily due to additional margins of approximately $51 million contributed by the SourceGas utilities in the first quarter of 2017 compared to the first quarter of 2016 which included approximately 1.5 months of SourceGas results. 2017 reflects a full twelve months of SourceGas results as compared to approximately 10.5 months in 2016.

Operations and maintenance increased primarily due to additional operating costs of approximately $19 million for the acquired SourceGas utilities, reflecting a full twelve months of results in 2017 as compared to approximately 10.5 months in 2016. Employee-related expenses increased $6.2 million for the Black Hills legacy gas utilities as a result of prior year integration activities and transition expenses charged to Corporate and Other. An additional $1.6 million of indirect corporate costs are included at the gas utilities; these costs were previously charged to our Oil and Gas segment, now reported as discontinued operations. A variety of smaller items contribute to the partially offsetting decrease in operations and maintenance expenses.

Depreciation and amortization increased primarily due to additional depreciation from the acquired SourceGas utilities.

Interest expense, net increased primarily due to additional interest expense from the acquired SourceGas utilities.

Other (expense) income, net was comparable to the same period in the prior year.

Income tax: The effective tax rate increased in 2017 primarily due to additional tax expense of $6.8 million as a result of the TCJA enacted on December 22, 2017 and from a $2.2 million tax benefit recognized in the prior year primarily related to favorable flow-through adjustments recognized in accordance with prescribed regulatory treatment. Partially offsetting these is a $4.1 million tax benefit recognized in the current year from a true-up to the filed 2016 SourceGas tax returns related to the SourceGas acquisition.

2016 Compared to 2015

Gross margin increased primarily due to margins of approximately $236 million contributed by the SourceGas utilities acquired on Feb. 12, 2016 and Energy West Wyoming utility acquired on July 1, 2015. Partially offsetting this increase is a $2.0 million decrease due to weather. Heating degree days were 1% lower than the prior year and 11% lower than normal.

Operations and maintenance increased primarily due to additional operating costs of approximately $111 million for the acquired SourceGas utilities and Energy West Wyoming utility. Partially offsetting this increase were approximately $7.4 million lower employee costs primarily driven by a change in expense allocations impacting the gas utilities as a result of integrating the acquired SourceGas utilities.

Depreciation and amortization increased primarily due to additional depreciation from the acquired SourceGas and Energy West Wyoming utilities of approximately $45 million, and due to a higher asset base at our other gas utilities over the same period in the prior year.

Interest expense, net increased primarily due to additional interest expense of approximately $58 million from the debt associated with the acquired SourceGas utilities.

Income tax: The effective tax rate for 2016, including the impact of the acquired SourceGas and Energy West Wyoming utilities, reflects additional tax benefits related primarily to a favorable flow through adjustment. Such adjustments are related to certain tax benefits that are recognized currently in accordance with prescribed regulatory treatment.

Power Generation

Our Power Generation segment operating results for the years ended December 31 were as follows (in thousands):

	2017	Variance	2016	Variance	2015
Revenue	$ 91,546	$ 415	$ 91,131	$ 341	$ 90,790
Operations and maintenance	32,382	(254)	32,636	496	32,140
Depreciation and amortization	5,993	1,889	4,104	(225)	4,329
Total operating expenses	38,375	1,635	36,740	271	36,469
Operating income	53,171	(1,220)	54,391	70	54,321
Interest expense, net	(2,836)	(1,061)	(1,775)	1,428	(3,203)
Other income (expense), net	(54)	(56)	2	(69)	71
Income tax benefit (expense)	10,333	27,462	(17,129)	1,410	(18,539)
Net income (loss)	60,614	25,125	35,489	2,839	32,650
Net income attributable to noncontrolling interest	(14,135)	(4,576)	(9,559)	(9,559)	—
Net income (loss) available for common stock	$ 46,479	$ 20,549	$ 25,930	$ (6,720)	$ 32,650

On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million. Black Hills Electric Generation continues to be the majority owner and operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric. Net income available for common stock for the year ended December 31, 2017 was reduced by $14 million, and reduced by $9.6 million for the year ended December 31, 2016. The net income allocable to the noncontrolling interest holders is based on ownership interests with the exception of certain agreed upon adjustments.

	2017	2016	2015
Contracted fleet plant availability:			
Gas-fired plants	99.2%	99.2%	99.1%
Coal-fired plants [(a)]	96.9%	95.5%	98.4%
Total	98.6%	98.3%	98.9%

(a) Wygen I experienced an unplanned outage in 2016 and a planned outage in 2017.

2017 Compared to 2016

Net income available for common stock for the Power Generation segment was $46 million for the year ended December 31, 2017, compared to Net income available for common stock of $26 million for the same period in 2016. Revenue and operating expenses were comparable to the same period in the prior year and depreciation expense increased on non-leased assets. The variance to the prior year was primarily driven by a $24 million current year tax benefit recognized from the revaluation of deferred tax liabilities in accordance with the TCJA enacted on December 22, 2017.

2016 Compared to 2015

Net income available for common stock for the Power Generation segment was $26 million for the year ended December 31, 2016, compared to Net income available for common stock of $33 million for the same period in 2015. The variance to the prior year was primarily attributable to the increase in noncontrolling interest of $9.6 million as a result of the noncontrolling interest sale in April 2016.

Mining

Mining operating results for the years ended December 31 were as follows (in thousands):

	2017	Variance	2016	Variance	2015
Revenue	$ 66,621	$ 6,341	$ 60,280	$ (4,786)	$ 65,066
Operations and maintenance	44,882	5,306	39,576	(2,054)	41,630
Depreciation, depletion and amortization	8,239	(1,107)	9,346	(460)	9,806
Total operating expenses	53,121	4,199	48,922	(2,514)	51,436
Operating income (loss)	13,500	2,142	11,358	(2,272)	13,630
Interest (expense) income, net	(205)	172	(377)	22	(399)
Other income, net	2,191	(18)	2,209	(38)	2,247
Income tax benefit (expense)	(1,100)	2,037	(3,137)	471	(3,608)
Net income (loss) available for common stock	$ 14,386	$ 4,333	$ 10,053	$ (1,817)	$ 11,870

The following table provides certain operating statistics for the Mining segment (in thousands):

	2017	2016	2015
Tons of coal sold	4,183	3,817	4,140
Cubic yards of overburden moved [(a)]	9,018	7,916	6,088
Coal reserves at year-end	194,909	199,905	203,849

(a) Increase in overburden was due to relocating mining operations to areas of the mine with higher overburden.

2017 Compared to 2016

Revenue increased primarily due to a 10 percent increase in tons sold driven primarily by an 11-week outage at the Wyodak plant in the prior year.

Operations and maintenance increased due to higher equipment major maintenance, higher overburden moved and higher royalties and production taxes on increased revenues.

Depreciation, depletion and amortization decreased primarily due to lower plant in service and lower asset retirement obligation costs.

Interest (expense) income, net was comparable to the same period in the prior year.

Income tax: The effective tax rate is lower in 2017 primarily due to a $2.7 million benefit resulting from revaluation of net deferred tax liabilities in accordance with the enactment of the TCJA on December 22, 2017.

2016 Compared to 2015

Revenue decreased primarily due to an 8 percent decrease in tons sold resulting from a planned five-week outage in the second quarter of 2016, which was extended by an additional six weeks at Wyodak plant due to an unplanned major repair of a turbine rotor. Pricing was comparable to the same period in the prior year. Approximately 50 percent of our coal production was sold under contracts that are priced based on actual mining costs, including income taxes, as compared to 46 percent for the same period in the prior year.

Operations and maintenance decreased due to lower major maintenance requirements, fuel costs, and employee costs, as well as decreased royalties and revenue-related taxes driven by decreased revenue compared to the same period in the prior year.

Depreciation, depletion and amortization decreased primarily due to revised cost estimates for our asset retirement obligation driving lower accretion and depreciation.

Interest (expense) income, net is comparable to the same period in the prior year.

Income tax: The effective tax rate was comparable to the same period in the prior year.

Corporate and Other

Corporate and Other represents certain unallocated expenses for corporate and other administrative activities and interest and taxes that support our reportable operating segments. Below is a summary of operating expenses and tax (expenses) benefits included in Corporate and Other for the years ended December 31:

(in thousands)	2017	Variance	2016	Variance	2015
Tax Reform Impact [a]	$ (28,402)	$ (28,402)	$ —	$ —	$ —
Tax Reform Impact - AOCI [a]	(7,000)	(7,000)	—	—	—
External acquisition costs, after-tax [b]	(2,489)	27,231	(29,720)	(23,020)	(6,700)
Internal acquisition labor, after-tax [b]	(500)	8,566	(9,066)	(6,066)	(3,000)
Discontinued operations operating expense reallocation [c]	(948)	2,540	(3,488)	764	(4,252)
Discontinued operations interest expense reallocation [c]	(3,215)	397	(3,612)	(1,369)	(2,243)
Tax benefit [d]	—	(4,400)	4,400	4,400	—
Other corporate expenses	(55)	2,761	(2,816)	846	(3,662)
Net (Loss) from Corporate and Other	$ (42,609)	$ 1,693	$ (44,302)	$ (24,445)	$ (19,857)

(a) Represents the revaluation of deferred tax balances not attributable to our operating segments or discontinued operations due to the decrease in the statutory Federal income tax rate as a result of the TCJA. Deferred taxes originally recorded to AOCI were also revalued to reflect the decrease in the statutory Federal income tax rate. See Notes 15 and 16 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more details.

(b) Acquisition and transition costs attributed to SourceGas acquisition including incremental transaction costs consisting of professional fees, financing fees, employee-related expenses and other miscellaneous costs and internal labor costs attributable to the acquisition that would otherwise have been charged to the other business segments.

(c) Reallocated indirect corporate operating costs and interest expenses previously allocated to BHEP which are not reclassified to discontinued operations in accordance with GAAP as they have a continuing impact on the Company. After-tax 2017 operating expenses of approximately $2.0 million were reallocated to our other business segments in 2017. See Note 21 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for more details.

(d) We recognized a $4.4 million tax benefit during 2016 as a result of an agreement reached with IRS Appeals relating to the release of the reserve for after-tax interest expense previously accrued with respect to the liability for uncertain tax positions involving a like-kind exchange transaction from 2008.

2017 Compared to 2016

Net (loss) available for common stock for the twelve months ended December 31, 2017, was $(43) million compared to net (loss) available for common stock of $(44) million for the same period in the prior year. The variance from the prior year was due to:

- Tax expense of $35 million not attributable to our operating segments reflecting the revaluation of deferred tax balances, including those originally recorded in AOCI, as a result of the TCJA;
- A decrease in acquisition and transition expenses of approximately $36 million driven by lower external acquisition costs and lower internal labor attributed to the SourceGas Acquisition;
- As a result of the Oil and Gas segment being reported as discontinued operations in 2017, indirect operating costs that would have been charged to this segment were reallocated to other business segments in 2017. These same costs in 2016 are reported as Corporate and Other;
- A decrease of approximately $4.4 million in tax benefits; and
- A decrease in other corporate expenses.

2016 Compared to 2015

Net (loss) available for common stock for the twelve months ended December 31, 2016, was $(44) million compared to net (loss) available for common stock of $(20) million for the same period in the prior year. The variance from the prior year was due to:

- An increase in acquisition and transition expenses of approximately $29 million driven by higher external costs and an increase in internal labor attributed to the SourceGas acquisition;
- An increase in allocated expenses from discontinued operations;
- An increase of approximately $4.4 million in tax benefits; and
- A decrease in other corporate expenses.

Discontinued Operations

Oil and Gas operating results included in discontinued operations for the years ended December 31 were as follows (in thousands):

	2017	Variance	2016	Variance	2015
Revenue	$ 25,382	$ (8,676)	$ 34,058	$ (9,225)	$ 43,283
Operations and maintenance	22,872	(4,315)	27,187	(8,274)	35,461
Depreciation, depletion and amortization	7,521	(5,989)	13,510	(15,328)	28,838
Impairment of long-lived assets	20,385	(86,572)	106,957	(142,651)	249,608
Total operating expenses	50,778	(96,876)	147,654	(166,253)	313,907
Operating (loss)	(25,396)	88,200	(113,596)	157,028	(270,624)
Interest income (expense), net	181	(517)	698	(233)	931
Other income (expense), net	(297)	(407)	110	488	(378)
Impairment of equity investments	—	—	—	4,405	(4,405)
Income tax benefit (expense)	8,413	(40,213)	48,626	(52,191)	100,817
(Loss) from discontinued operations available for common stock	$ (17,099)	$ 47,063	$ (64,162)	$ 109,497	$ (173,659)

The following tables provide certain operating statistics for Oil and Gas results included in discontinued operations:

Crude Oil and Natural Gas Production	2017	2016	2015
Bbls of oil sold	181,408	318,613	371,493
Mcf of natural gas sold	8,700,612	9,430,288	10,057,378
Bbls of NGL sold	113,233	133,304	101,684
Mcf equivalent sales	10,468,458	12,141,790	12,896,440

Average Price Received [(a)]	2017	2016	2015
Gas/Mcf	$ 1.49	$ 1.36	$ 1.78
Oil/Bbl	$ 46.50	$ 57.34	$ 60.69
NGL/Bbl	$ 22.28	$ 12.27	$ 13.66

(a) Net of hedge settlement gains/losses

	2017	2016	2015
Depletion expense/Mcfe [(a)]	$ 0.39	$ 0.79	$ 1.91

(a) Full cost accounting was no longer applicable at November 1, 2017 and depletion was not recorded after November 1, 2017. The average depletion rate per Mcfe is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented. See Note 22 of Notes to the Consolidated Financial Statements included in this Annual Report filed on Form 10-K.

The following is a summary of certain annual average costs per Mcfe at December 31:

	LOE	Gathering, Compression, Processing and Transportation	Production Taxes	Total
2017 Average	$ 0.96	$ 1.33	$ 0.23	$ 2.52
2016 Average	$ 1.05	$ 1.20	$ 0.18	$ 2.43
2015 Average	$ 1.03	$ 1.23	$ 0.32	$ 2.58

In the Piceance and San Juan Basins, our natural gas is transported through our own and third-party gathering systems and pipelines, for which we incur processing, gathering, compression and transportation fees. The sales price for natural gas, condensate and NGLs is reduced for these third-party costs, and the cost of operating our own gathering systems is included in operations and maintenance. The gathering, compression, processing and transportation costs shown in the tables above include amounts paid to third parties, as well as costs incurred in operations associated with our own gas gathering, compression, processing and transportation.

The ten-year gas gathering and processing contract for natural gas production in the Piceance Basin in Colorado that became effective in 2014 is part of the sale of our Piceance property. We won't have any further commitment on this contract when the Piceance asset is sold, which we expect to be before March 31, 2018. This take-or-pay contract requires a minimum fee based on a throughput of 20,000 Mcf per day, regardless of the volume delivered. Gathering, compression and processing costs on a per Mcfe basis, as shown in the tables above, were higher in periods when the minimum contract requirements were not met.

2017 Compared to 2016

Revenue decreased primarily due to a decrease in production from the current year and prior year property sales and a decrease in the average price received, including hedges, for crude oil sold, partially offset by an increase in the average price received, including hedges, for natural gas sold.

Operations and maintenance decreased primarily due to lower employee costs as a result of the reduction in staffing and lower production taxes and ad valorem taxes on lower production and lower revenue driven by property sales.

Depreciation, depletion and amortization decreased due to the reduction of our full cost pool resulting from the prior year ceiling test impairments and no depletion recorded on assets held for sale beginning on November 1, 2017.

Impairment of long-lived assets represents a $20 million non-cash fair value impairment of assets held for sale in 2017 compared to prior year impairments that included a $14 million write-down of depreciable properties excluded from our full-cost pool and a ceiling test write-down of $93 million.

Interest income (expense), net decreased primarily due to lower capitalized interest expense.

Income tax (expense) benefit: Each period reflects a tax benefit. The effective tax rate for 2016 was impacted by a benefit of approximately $5.8 million from additional percentage depletion deductions being claimed with respect to a change in estimate for tax purposes. Such deductions are primarily the result of a change in the application of the maximum daily limitation of 1,000 Bbls of oil equivalent allowed under the Internal Revenue Code.

2016 Compared to 2015

Revenue decreased primarily due to lower commodity prices for both crude oil and natural gas, resulting in a 24 percent decrease in the average price received, including hedges, for natural gas sold and a 6 percent decrease in the average price received, including hedges, for crude oil sold. In addition, production decreased by 6 percent as compared to prior year as we limited natural gas production to meet minimum daily quantity contractual gas processing commitments in the Piceance. Crude oil production also decreased due to non-core property sales in the fourth quarter of 2016.

Operations and maintenance decreased primarily due to lower employee costs as a result of the reduction in staffing in the prior year, and lower production taxes and ad valorem taxes on lower revenue.

Depreciation, depletion and amortization decreased primarily due to a reduction of our full cost pool resulting from the ceiling test impairments incurred in current and prior years.

Impairment of long-lived assets represents a non-cash write-down in the value of our natural gas and crude oil properties driven by low natural gas and crude oil prices and movement of certain unevaluated assets into the full-cost pool. The write-down of $107 million included a $14 million write-down of depreciable properties excluded from our full-cost pool and a ceiling test write-down of $93 million. The ceiling test write-down for the 12 months ended December 31, 2016 used an average NYMEX natural gas price of $2.48 per Mcf, adjusted to $2.25 per Mcf at the wellhead, and $42.75 per barrel for crude oil, adjusted to $37.35 per barrel at the wellhead, compared to the $250 million ceiling test write-down in the same period of the prior year which used an average NYMEX natural gas price of $2.59 per Mcf, adjusted to $1.27 per Mcf at the wellhead, and $50.82 per barrel for crude oil, adjusted to $44.72 per barrel at the wellhead.

Interest income (expense), net increased primarily due to higher capitalized interest compared to the same period in the prior year.

Impairment of equity investments represents a prior year non-cash write-down in equity investments related to interests in a pipeline and gathering system. The impairment resulted from continued declining performance, market conditions, and a change in view of the economics of the facilities that we considered to be other than temporary.

Income tax (expense) benefit: Each period reflects a tax benefit. The effective tax rate for 2016 was impacted by a benefit of approximately $5.8 million from additional percentage depletion deductions being claimed with respect to a change in estimate for tax purposes. Such deductions are primarily the result of a change in the application of the maximum daily limitation of 1,000 Bbls of oil equivalent allowed under the Internal Revenue Code.

Critical Accounting Policies Involving Significant Accounting Estimates

We prepare our consolidated financial statements in conformity with GAAP. In many cases, the accounting treatment of a particular transaction is specifically dictated by GAAP and does not require management's judgment in application. There are also areas which require management's judgment in selecting among available GAAP alternatives. We are required to make certain estimates, judgments and assumptions that we believe are reasonable based upon the information available. These estimates and assumptions affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. Actual results may differ from our estimates and to the extent there are material differences between these estimates, judgments, or assumptions and actual results, our financial statements will be affected. We believe the following accounting estimates are the most critical in understanding and evaluating our reported financial results. We have reviewed these critical accounting estimates and related disclosures with our Audit Committee.

The following discussion of our critical accounting estimates should be read in conjunction with Note 1, "Business Description and Significant Accounting Policies" of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Goodwill

We perform a goodwill impairment test on an annual basis or upon the occurrence of events or changes in circumstances that indicate that the asset might be impaired. Beginning in 2016, we changed our annual goodwill impairment testing date from November 30 to October 1 to better align the testing date with our financial planning process. We believe that the change in the date of the annual goodwill impairment test from November 30 to October 1 is not a material change in the application of an accounting principle. The new and old testing dates are close in proximity and both are in the fourth quarter of the year. We would not expect a materially different outcome as a result of testing on October 1 as compared to November 30. The change in assessment date does not have a material effect on the financial statements.

Accounting standards for testing goodwill for impairment require a two-step process be performed to analyze whether or not goodwill has been impaired. Goodwill is tested for impairment at the reporting unit level. The first step of this test, used to identify potential impairment, compares the estimated fair value of a reporting unit with its carrying amount, including goodwill. If the carrying amount exceeds fair value under the first step, then the second step of the impairment test is performed to measure the amount of any impairment loss.

Application of the goodwill impairment test requires judgment, including the identification of reporting units and determining the fair value of the reporting unit. We have determined that the reporting units for goodwill impairment testing are our operating segments, or components of an operating segment, that constitute a business for which discrete financial information

is available and for which segment management regularly reviews the operating results. We estimate the fair value of our reporting units using a combination of an income approach, which estimates fair value based on discounted future cash flows, and a market approach, which estimates fair value based on market comparables within the utility and energy industries. These valuations require significant judgments, including, but not limited to: 1) estimates of future cash flows, based on our internal five-year business plans and adjusted as appropriate for our view of market participant assumptions, with long range cash flows estimated using a terminal value calculation, 2) estimates of long-term growth rates for our businesses, 3) the determination of an appropriate weighted-average cost of capital or discount rate, and 4) the utilization of market information such as recent sales transactions for comparable assets within the utility and energy industries. Varying by reporting unit, weighted average cost of capital in the range of 5% to 8% and long-term growth rate projections in the 1% to 2% range were utilized in the goodwill impairment test performed in the fourth quarter of 2017. Although 1% to 2% was used for a long-term growth rate projection, the short-term projected growth rate is higher with planned recovery of capital investments through rider mechanisms and rate reviews, as well as other improved efficiency and cost reduction initiatives. Under the market approach, we estimate fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, we add a reasonable control premium when calculating fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants.

The estimates and assumptions used in the impairment assessments are based on available market information, and we believe they are reasonable. However, variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated. For the years ended December 31, 2017, 2016, and 2015, there were no significant impairment losses recorded. At December 31, 2017, the fair value substantially exceeded the carrying value at all reporting units.

Accounting for Oil and Gas Activities

Impairment testing of assets held for sale

We are in the process of divesting our Oil and Gas segment; therefore, we performed a fair value assessment of the assets and liabilities classified as held for sale. We evaluated our disposal groups classified as held for sale based on the lower of carrying value or fair value less cost to sell. For the assets that have not yet been sold, the estimated fair value of our oil and gas assets was determined using the market approaches. The market approach was based on our recent fourth quarter 2017 sale of our Powder River Basin assets and pending sale transactions of our other properties.

There is risk involved when determining the fair value of assets, as there may be unforeseen events and changes in circumstances and market conditions that have a material impact on the estimated amount and timing of future cash flows. In addition, the fair value of the assets and liabilities could be different using different estimates and assumptions in the valuation techniques used. We believe that the estimates used in calculating the fair value of our assets and liabilities held for sale are reasonable based on the information that was known when the estimates were made.

At December 31, 2017, the fair value of our held-for-sale assets was less than our carrying value, which required an after-tax write down of $13 million. For additional information, see Note 21 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Full Cost Method of Accounting for Oil and Gas Activities

Prior to the November 1, 2017 decision to divest our oil and gas business, we accounted for oil and gas activities under the full cost method of accounting, whereby all productive and nonproductive costs related to acquisition, exploration, development, abandonment and reclamation activities were capitalized. Accounting for oil and gas activities is subject to industry-specific rules. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are generally treated as adjustments to the cost of the properties with no gain or loss recognized. Net capitalized costs are subject to a ceiling test that limits such costs to the aggregate of the present value of future net revenues of proved reserves and the lower of cost or fair value of unproved properties. This method values the reserves based upon SEC-defined prices for oil and gas as of the end of each reporting period adjusted for contracted price changes. The prices, as well as costs and development capital, are assumed to remain constant for the remaining life of the properties. If the net capitalized costs exceed the full-cost ceiling, then a permanent non-cash write-down is required to be charged to earnings in that reporting period. Under these SEC-defined product prices, our net capitalized costs were more than the full cost ceiling throughout 2016 and 2015, which required after-tax write-downs of $58 million and $158 million for the years ended December 31, 2016 and 2015, respectively. Reserves in 2016 and 2015 were

determined consistent with SEC requirements using a 12-month average price calculated using the first-day-of-the-month price for each of the 12 months in the reporting period held constant for the life of the properties adjusted for contracted price changes.

Oil, Natural Gas, and Natural Gas Liquids Reserve Estimates

Estimates of our proved crude oil, natural gas and NGL reserves are based on the quantities of each that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Prior to November 1, 2017, an independent petroleum engineering company prepared reports that estimate our proved oil, natural gas and NGL reserves annually. The accuracy of any crude oil, natural gas and NGL reserve estimate is a function of the quality of available data, engineering judgment and geological interpretation. For example, we must estimate the amount and timing of future operating costs, severance taxes, development costs and work over costs, all of which may in fact vary considerably from actual results. In addition, as crude oil, natural gas and NGL prices and cost levels change from year to year, the estimate of proved reserves may also change. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

Estimates for our crude oil, natural gas, and NGL reserves are used throughout our financial statements. For example, since we used the unit-of-production method of calculating depletion expense, the amortization rate of our capitalized oil and gas properties incorporated the estimated unit-of-production attributable to the estimates of proved reserves. Under full-cost accounting, the net book value of our crude oil and gas properties was also subject to a “ceiling” limitation based in large part on the value of our proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures.

Pension and Other Postretirement Benefits

As described in Note 18 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K, we have one defined benefit pension plan, and several defined post-retirement healthcare plans and non-qualified retirement plans. A Master Trust holds the assets for the pension plan. Trusts for the funded portion of the post-retirement healthcare plans have also been established.

Accounting for pension and other postretirement benefit obligations involves numerous assumptions, the most significant of which relate to the discount rates, health care cost trend rates, expected return on plan assets, compensation increases, retirement rates and mortality rates. The determination of our obligation and expenses for pension and other postretirement benefits is dependent on the assumptions determined by management and used by actuaries in calculating the amounts. Although we believe our assumptions are appropriate, significant differences in our actual experience or significant changes in our assumptions may materially affect our pension and other postretirement obligations and our future expense.

The pension benefit cost for 2018 for our non-contributory funded pension plan is expected to be $6.3 million compared to $2.1 million in 2017. The increase in pension benefit cost is driven primarily by a decrease in the discount rate.

Beginning in 2016, the Company changed the method used to estimate the service and interest cost components of the net periodic pension, supplemental non-qualified defined benefit and other postretirement benefit costs. The new method used the spot yield curve approach to estimate the service and interest costs by applying the specific spot rates along the yield curve used to determine the benefit obligations to relevant projected cash outflows. Prior to 2016, the service and interest costs were determined using a single weighted-average discount rate based on hypothetical AA Above Median yield curves used to measure the benefit obligation at the beginning of the period. The change does not affect the measurement of the total benefit obligations as the change in service and interest costs offsets the actuarial gains and losses recorded in other comprehensive income.

The Company changed to the new method to provide a more precise measure of service and interest costs by improving the correlation between the projected benefit cash flows and the discrete spot yield curve rates. The Company accounted for this change as a change in estimate prospectively beginning in 2016.

The effect of hypothetical changes to selected assumptions on the pension and other postretirement benefit plans would be as follows in thousands of dollars:

		December 31,	
Assumptions	Percentage Change	2017 Increase/(Decrease) PBO/APBO [a]	2018 Increase/(Decrease) Expense - Pretax
Pension			
Discount rate [b]	+/- 0.5	(28,825)/31,769	(3,477)/3,784
Expected return on assets	+/- 0.5	N/A	(1,978)/1,981
OPEB			
Discount rate [b]	+/- 0.5	(3,025)/3,299	(119)/147
Expected return on assets	+/- 0.5	N/A	(40)/40
Health care cost trend rate [b]	+/- 1.0	2,968/(2,534)	377/(322)

(a) Projected benefit obligation (PBO) for the pension plan and accumulated postretirement benefit obligation (APBO) for OPEB plans.
(b) Impact on service cost, interest cost and amortization of gains or losses.

Regulation

Our utility operations are subject to regulation with respect to rates, service area, accounting, and various other matters by state and federal regulatory authorities. The accounting regulations provide that rate-regulated public utilities account for and report assets and liabilities consistent with the economic effects of the manner in which independent third-party regulators establish rates. Regulatory assets generally represent incurred or accrued costs that have been deferred when future recovery from customers is probable. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs.

Management continually assesses the probability of future recoveries and obligations associated with regulatory assets and liabilities. Factors such as the current regulatory environment, recently issued rate orders, and historical precedents are considered. As a result, we believe that the accounting prescribed under rate-based regulation remains appropriate and our regulatory assets are probable of recovery in current rates or in future rate proceedings.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. As a result of the SourceGas transaction, certain acquired subsidiaries file as a separate consolidated group. Each tax-paying entity records income taxes as if it were a separate taxpayer and consolidating adjustments are allocated to the subsidiaries based on separate company computations of taxable income or loss.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA makes broad and complex changes to the U.S. tax code, including, but not limited to reducing the U.S. federal corporate tax rate from 35% to 21%. The Company uses the asset and liability method in accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. The entities subject to regulatory construct have made their best estimate regarding the probability of settlements of net regulatory liabilities established pursuant to the TCJA. The amount of the settlements may change based on decisions and actions by the rate regulators, which could have a material impact on the Company’s future results of operations, cash flows or financial position.

The Company has revalued the deferred income taxes at the 21% federal tax rate as of December 31, 2017 and as a result, deferred tax assets and liabilities were reduced by approximately $309 million. Of the $309 million, approximately $301 million is related to our regulated utilities and is reclassified to a regulatory liability. This regulatory liability will generally be amortized over the remaining life of the related assets using the normalization principles as specifically prescribed in the TCJA.

As allowed under SEC Staff Accounting Bulletin No. 118 (SAB 118), the Company has recorded provisional income tax amounts as of December 31, 2017 for changes pursuant to the TCJA related to depreciation, for which the impacts could not be finalized upon issuance of the Company's financial statements but reasonable estimates could be determined. The provisional amounts may change as the Company finalizes the analysis and computations and such changes could be material to the Company's future results of operations, cash flows or financial position.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. If we determine that we will be unable to realize all or part of our deferred tax assets in the future, an adjustment to the deferred tax asset would be charged to income in the period such determination was made. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax laws or our interpretations of tax laws and the resolution of current and any future tax audits could significantly impact the amounts provided for income taxes in our consolidated financial statements.

See Note 15 in the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

Business Combinations

We record acquisitions in accordance with ASC 805, *Business Combinations,* with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. The excess of the purchase price over the estimated fair values of the net tangible and net intangible assets acquired is recorded as goodwill. The application of ASC 805, *Business Combinations* requires management to make significant estimates and assumptions in the determination of the fair value of assets acquired and liabilities assumed in order to properly allocate purchase price consideration between goodwill and assets that are depreciated and amortized. Pertaining to our 2016 acquisition of SourceGas, substantially all of SourceGas' operations are subject to the rate-setting authority of state regulatory commissions, and are accounted for in accordance with GAAP for regulated operations. SourceGas' assets and liabilities subject to rate setting provisions provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. As such, the fair value of these assets and liabilities equal their historical net book values.

Our estimates are based on historical experience, information obtained from the management of the acquired companies and, when appropriate, include assistance from independent third-party appraisal firms. These estimates are inherently uncertain and unpredictable. In addition, unanticipated events or circumstances may occur which may affect the accuracy or validity of such estimates. See Note 2 in the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

Liquidity and Capital Resources

OVERVIEW

Our company requires significant cash to support and grow our businesses. Our predominant source of cash is supplied by our operations and supplemented with corporate financings. This cash is used for, among other things, working capital, capital expenditures, dividends, pension funding, investments in or acquisitions of assets and businesses, payment of debt obligations and redemption of outstanding debt and equity securities when required or financially appropriate. As discussed in more detail below under income taxes, we expect an increase in working capital requirements as a result of complying with the TCJA and the impact of providing TCJA benefits to customers.

The most significant uses of cash are our capital expenditures, the purchase of natural gas for our Gas Utilities and our Power Generation segment, as well as the payment of dividends to our shareholders. We experience significant cash requirements during peak months of the winter heating season due to higher natural gas consumption and during periods of high natural gas prices, as well as during the summer construction season.

We believe that our cash on hand, operating cash flows, existing borrowing capacity and ability to complete new debt and equity financings, taken in their entirety, provide sufficient capital resources to fund our ongoing operating requirements, regulatory liabilities, debt maturities, anticipated dividends, and anticipated capital expenditures discussed in this section.

The following table provides an informational summary of our financial position as of December 31 (dollars in thousands):

Financial Position Summary	2017	2016
Cash and cash equivalents	$ 15,420	$ 13,518
Restricted cash and equivalents	$ 2,820	$ 2,274
Short-term debt, including current maturities of long-term debt	$ 217,043	$ 102,343
Long-term debt [(a)]	$ 3,109,400	$ 3,211,189
Stockholders' equity	$ 1,708,974	$ 1,614,639
Ratios		
Long-term debt ratio	64%	67%
Total debt ratio	66%	67%

(a) Carrying amount of long-term debt is net of deferred financing costs.

Significant Factors Affecting Liquidity

Although we believe we have sufficient resources to fund our cash requirements, there are many factors with the potential to influence our cash flow position, including seasonality, commodity prices, significant capital projects and acquisitions, requirements imposed by state and federal agencies and economic market conditions. We have implemented risk mitigation programs, where possible, to stabilize cash flow. However, the potential for unforeseen events affecting cash needs will continue to exist.

Our Utilities maintain wholesale commodity contracts for the purchases and sales of electricity and natural gas which have performance assurance provisions that allow the counterparty to require collateral postings under certain conditions, including when requested on a reasonable basis due to a deterioration in our financial condition or nonperformance. A significant downgrade in our credit ratings, such as a downgrade to a level below investment grade, could result in counterparties requiring collateral postings under such adequate assurance provisions. The amount of credit support that we may be required to provide at any point in the future is dependent on the amount of the initial transaction, changes in the market price, open positions and the amounts owed by or to the counterparty. At December 31, 2017, we had sufficient liquidity to cover collateral that could be required to be posted under these wholesale commodity contracts.

Weather Seasonality, Commodity Pricing and Associated Hedging Strategies

We manage liquidity needs through hedging activities, primarily in connection with seasonal needs of our utility operations (including seasonal peaks in fuel requirements), interest rate movements and commodity price movements.

Utility Factors

Our cash flows, and in turn liquidity needs in many of our regulated jurisdictions, can be subject to fluctuations in weather and commodity prices. Since weather conditions are uncontrollable, we have implemented commission-approved natural gas hedging and storage programs in many of our regulated jurisdictions to mitigate significant changes in natural gas commodity pricing. We target hedging of approximately 40% to 70% of our forecasted natural gas supply using options, futures and basis swaps.

Interest Rates

Several of our debt instruments have a variable interest rate component which can change significantly depending on the economic climate. We don't have any interest rate swap agreements at December 31, 2017; 84% of our interest rate exposure has been mitigated through fixed interest rates.

Federal and State Regulations

Federal

We are structured as a utility holding company which owns several regulated utilities. Within this structure, we are subject to various regulations by our commissions that can influence our liquidity. As an example, the issuance of debt by our regulated subsidiaries and the use of our utility assets as collateral generally require the prior approval of the state regulators in the state in which the utility assets are located. Furthermore, as a result of our holding company structure, our right as a common shareholder to receive assets of any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is subordinate to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities and guarantee holders.

Income Tax

The TCJA legislation was signed into law on December 22, 2017. The new tax law required revaluation of federal deferred tax assets and liabilities using the new lower corporate tax rate of 21%. As a result of the revaluation, deferred tax assets and liabilities were reduced by approximately $309 million. Of the $309 million, approximately $301 million is related to our regulated utilities and is reclassified to a regulatory liability. This regulatory liability will generally be amortized over the remaining life of the related assets as specifically prescribed in the TCJA.

We are working with utility regulators in each of the states we serve to provide benefits from tax reform to our customers. We expect an increase in working capital requirements as a result of complying with the TCJA and the impact of providing TCJA benefits to customers. We estimate the lower tax rate will negatively impact the company’s cash flows by approximately $35 million to $45 million annually for the next several years.

Acceleration of depreciation for tax purposes, including 50% bonus depreciation, was previously available for certain property placed in service through September 27, 2017. The TCJA, signed into law on December 22, 2017, enacted 100% bonus depreciation generally to qualifying property acquired and placed in service after September 27, 2017 and before January 1, 2023. After 2022, bonus depreciation would reduce 20% per year with 80% bonus depreciation generally to qualifying property placed in serving during 2023, 60% bonus depreciation generally to qualifying property placed in service during 2024, 40% bonus depreciation generally to qualifying property placed in service during 2025 and 20% generally to qualifying property placed in service after December 31, 2025 and before January 1, 2027. The provision would expand the property that is eligible for this immediate expensing by repealing the requirement that the original use of the property begin with the taxpayer. Instead, the property would be eligible for the additional depreciation if it is the taxpayer’s first use. Under the provision, qualified property eligible for bonus depreciation, including immediate expensing, would not include any property used by a regulated public utility company or any property used in a real property trade or business. These depreciation provisions resulted in cash tax benefits for BHC as indicated in the table below:

(in millions)	2017	2016	2015
Tax benefit	$37	$81	$33

In addition, bonus depreciation will apply to qualifying property whose construction and completion period encompasses multiple tax years. The exception being with respect to costs that would be incurred in 2027 when, under current law, bonus depreciation is scheduled to expire.

The effect of additional depreciation deductions as a result of bonus depreciation will serve to reduce taxable income and contribute to extending the tax loss carryforwards from being fully utilized until 2022 based on current projections.

See Note 15 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

CASH GENERATION AND CASH REQUIREMENTS

Cash Generation

Our primary sources of cash are generated from operating activities, our five-year Revolving Credit Facility expiring August 9, 2021, our CP Program and our ability to access the public and private capital markets through debt and securities offerings when necessary.

Cash Collateral

Under contractual agreements and exchange requirements, BHC or its subsidiaries have collateral requirements, which if triggered, require us to post cash collateral positions with the counterparty to meet these obligations.

We have posted the following amounts of cash collateral with counterparties at December 31 (in thousands):

Purpose of Cash Collateral	2017	2016
Natural Gas Futures and Basis Swaps Pursuant to Utility Commission Approved Hedging Programs	$ 7,694	$ 12,722
Natural Gas Over-the-Counter Swaps Pursuant to Master Agreements for Derivative Instruments	$ 562	$ —

DEBT

Financing Transactions and Short-Term Liquidity

Our principal sources to meet day-to-day operating cash requirements are cash from operations, our CP Program and our corporate Revolving Credit Facility.

Revolving Credit Facility and CP Program

On August 9, 2016, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extended the term through August 9, 2021 with two one-year extension options. This facility is similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents, to increase total commitments of the facility to up to $1 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our most favorable Corporate credit rating from S&P or Moody's for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.250%, 1.250%, and 1.250%, respectively, at December 31, 2017. A 0.200% commitment fee is charged on the unused amount of the Revolving Credit Facility.

On December 22, 2016, we implemented a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. The notes issued under the CP Program may have maturities not to exceed 397 days from the date of issuance and bear interest (or are sold at par less a discount representing an interest factor) based on, among other things, the size and maturity date of the note, the frequency of the issuance and our credit ratings. Under the CP Program, any borrowings rank equally with our unsecured debt. Notes under the CP Program are not registered and are offered and issued pursuant to a registration exemption.

Our Revolving Credit Facility had the following borrowings, outstanding letters of credit, and available capacity (in millions):

Credit Facility	Expiration	Current Capacity	Revolver Borrowings at December 31, 2017	CP Program Borrowings at December 31, 2017	Letters of Credit at December 31, 2017	Available Capacity at December 31, 2017
Revolving Credit Facility	August 9, 2021	$ 750	$ —	$ 211	$ 27	$ 512

The weighted average interest rate on CP Program borrowings at December 31, 2017 was 1.76%. Revolving Credit Facility and CP Program financing activity for the twelve months ended December 31, 2017 was (dollars in millions):

		For the Twelve Months Ended December 31, 2017
Maximum amount outstanding - commercial paper (based on daily outstanding balances)	$	282
Maximum amount outstanding - revolving credit facility (based on daily outstanding balances) [(a)]	$	97
Average amount outstanding - commercial paper (based on daily outstanding balances)	$	139
Average amount outstanding - revolving credit facility (based on daily outstanding balances) [(a)]	$	55
Weighted average interest rates - commercial paper		1.34%
Weighted average interest rates - revolving credit facility [(a)]		2.07%

(a) Averages for the Revolving Credit Facility are for the first 29 days of the year after which all borrowings were through the CP Program.

The Revolving Credit Facility contains customary affirmative and negative covenants, such as limitations on certain liens, restrictions on certain transactions, and maintenance of a certain Consolidated Indebtedness to Capitalization Ratio. Under the Revolving Credit Facility, our Consolidated Indebtedness to Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness, which includes letters of credit, certain guarantees issued and excludes RSNs by (ii) Capital, which includes Consolidated Indebtedness plus Net Worth, which excludes noncontrolling interests in subsidiaries and includes the aggregate outstanding amount of the RSNs. Subject to applicable cure periods, a violation of any of these covenants would constitute an event of default that entitles the lenders to terminate their remaining commitments and accelerate all principal and interest outstanding. We were in compliance with these covenants as of December 31, 2017.

The Revolving Credit Facility prohibits us from paying cash dividends if a default or an event of default exists prior to, or would result after, paying a dividend. Although these contractual restrictions exist, we do not anticipate triggering any default measures or restrictions.

Capital Resources

Our principal sources for our long-term capital needs have been issuances of long-term debt securities by the Company and its subsidiaries along with proceeds obtained from public and private offerings of equity and proceeds from our ATM equity offering program.

Financing Activities

Financing activities for 2017 consisted of short-term borrowings from our Revolving Credit Facility and CP Program. We also made principal payments of $50 million each on May 16, 2017 and July 17, 2017 on our Corporate term loan due August 9, 2019. Short-term borrowings from our CP program were used to fund the payments on the Corporate term loan. On August 4, 2017, we renewed the ATM equity offering program which reset the size of the ATM equity offering program to an aggregate value of up to $300 million. We did not issue any shares of common stock under our ATM equity offering program during 2017.

Financing activities from the prior year consisted of completing the permanent financing for the SourceGas Acquisition. In addition to the net proceeds of $536 million from our November 2015 equity issuances, we completed the Acquisition financing with $546 million of net proceeds from our January 2016 debt offering. We also refinanced the long-term debt assumed with the SourceGas Acquisition primarily through $693 million of net proceeds from our August 19, 2016 debt offerings. In addition to our debt refinancings, we issued a total of 1.97 million shares of common stock throughout 2016 for net proceeds of approximately $119 million through our ATM equity offering program, and sold a 49.9% noncontrolling interest in Black Hills Colorado IPP for $216 million in April 2016.

Future Financing Plans

We anticipate the following financing activities:

- Remarketing the junior subordinated notes maturing in 2018;
- Evaluating an extension of our Revolving Credit Facility and CP program; and
- Evaluating refinancing options for term loan and short-term borrowings under our Revolving Credit Facility and CP program.

Cross-Default Provisions

Our $300 million and $19 million corporate term loans contain cross-default provisions that could result in a default under such agreements if BHC or its material subsidiaries failed to make timely payments of debt obligations or triggered other default provisions under any debt agreement totaling, in the aggregate principal amount of $50 million or more that permits the acceleration of debt maturities or mandatory debt prepayment. Our Revolving Credit Facility contains the same provisions and a threshold principal amount is $50 million.

The Revolving Credit Facility prohibits us from paying cash dividends if we are in default or if paying dividends would cause us to be in default.

Equity

Based on our current capital spending forecast, we do not anticipate the need to further access the equity capital markets in the next three years.

Shelf Registration

We have an effective automatic shelf registration statement on file with the SEC under which we may issue, from time to time, senior debt securities, subordinated debt securities, common stock, preferred stock, warrants and other securities. Although the shelf registration statement does not limit our issuance capacity, our ability to issue securities is limited to the authority granted by our Board of Directors, certain covenants in our financing arrangements and restrictions imposed by federal and state regulatory authorities. We renewed our shelf registration on August 4, 2017. Our articles of incorporation authorize the issuance of 100 million shares of common stock and 25 million shares of preferred stock. As of December 31, 2017, we had approximately 55 million shares of common stock outstanding and no shares of preferred stock outstanding.

Common Stock Dividends

Future cash dividends, if any, will be dependent on our results of operations, financial position, cash flows, reinvestment opportunities and other factors, and will be evaluated and approved by our Board of Directors.

On January 31, 2018, our Board of Directors declared a quarterly dividend of $0.475 per share or an annualized equivalent dividend rate of $1.90 per share. The table below provides our historical three-year dividend payout ratio and dividends paid per share:

	2017	2016	2015
Dividend Payout Ratio	50%	65%	52%
Dividends Per Share	$1.81	$1.68	$1.62

Our three-year compound annualized dividend growth rate was 5.1% and all dividends were paid out of available operating cash flows.

Dividend Restrictions

As a utility holding company which owns several regulated utilities, we are subject to various regulations that could influence our liquidity. For example, the issuance of debt by our utility subsidiaries (including the ability of Black Hills Utility Holdings to issue debt) and the use of our utility assets as collateral generally requires the prior approval of the state regulators in the state in which the utility assets are located. As a result of our holding company structure, our right as a common shareholder to receive assets from any of our direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is junior to the claims against the assets of such subsidiaries by their creditors. Therefore, our holding company debt obligations are effectively subordinated to all existing and future claims of the creditors of our subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities and guarantee holders.

Our credit facilities and other debt obligations contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be deemed to have occurred if we did not comply with certain financial or other covenants. At December 31, 2016, our Revolving Credit Facility and Corporate term loans included a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.70 to 1.00, changing to 0.65 to 1.00 in subsequent quarters, beginning March 31, 2017. As of December 31, 2017, we were in compliance with these covenants.

In addition, the agreements governing our equity units generally restrict the payment of cash dividends at any time we have exercised our right to defer payment of contract adjustment payments under the purchase contracts or interest payments under the junior subordinated notes included in such equity units. Moreover, holders of purchase contracts will be entitled to additional shares of our common stock upon settlement of the purchase contracts if we pay regular quarterly dividends in excess of $0.405 per share while the purchase contracts are outstanding. As of December 31, 2017, we haven't exercised our right to defer payment. On January 31, 2018, we declared a quarterly dividend of $0.475 per share.

Covenants within Wyoming Electric's financing agreements require Wyoming Electric to maintain a debt to capitalization ratio of no more than .60 to 1.00. Our utilities in Arkansas, Colorado, Iowa, Kansas and Nebraska have regulatory agreements in which they cannot pay dividends if they have issued debt to third parties and the payment of a dividend would reduce their equity ratio to below 40% of their total capitalization; and neither Black Hills Utility Holdings nor its utility subsidiaries can extend credit to the Company except in the ordinary course of business and upon reasonable terms consistent with market terms. Additionally, our utility subsidiaries may generally be limited to the amount of dividends allowed by state regulatory authorities to be paid to us as a utility holding company and also may have further restrictions under the Federal Power Act. As of December 31, 2017, the restricted net assets at our Electric and Gas Utilities were approximately $257 million.

Utility Money Pool

As a utility holding company, we are required to establish a cash management program to address lending and borrowing activities between our utility subsidiaries and the Company. We have established utility money pool agreements which address these requirements. These agreements are on file with the FERC and appropriate state regulators. Under the utility money pool agreements, our utilities may at their option, borrow and extend short-term loans to our other utilities via a utility money pool at market-based rates (1.962% at December 31, 2017). While the utility money pool may borrow funds from the Company (as ultimate parent company), the money pool arrangement does not allow loans from our utility subsidiaries to the Company (as ultimate parent company) or to non-regulated affiliates.

At December 31, money pool balances included (in thousands):

	Borrowings From (Loans To) Money Pool Outstanding	
Subsidiary	2017	2016
Black Hills Utility Holdings	$ 35,693	$ 52,370
South Dakota Electric	13,397	(28,409)
Wyoming Electric	15,290	20,737
Total Money Pool borrowings from Parent	$ 64,380	$ 44,698

CASH FLOW ACTIVITIES

The following table summarizes our cash flows (in thousands):

	2017	2016	2015
Cash provided by (used in)			
Operating activities	$ 428,261	$ 320,479	$ 424,383
Investing activities	$ (317,664)	$ (1,588,742)	$ (476,389)
Financing activities	$ (108,695)	$ 840,998	$ 483,702

2017 Compared to 2016

Operating Activities:

Net cash provided by operating activities was $108 million higher than in 2016. The variance to the prior year was primarily attributable to:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $68 million higher than prior year;
- Net outflow from operating assets and liabilities was $16 million lower than prior year, primarily attributable to:
  - Cash outflows decreased by approximately $4.8 million as a result of changes in accounts payable and accrued liabilities driven by changes in working capital requirements;
  - Cash outflows decreased by approximately $20 million compared to the prior year as a result of lower accounts receivable due to warmer weather partially offset by higher natural gas inventory; and
  - Cash outflows increased by approximately $9.5 million primarily as a result of changes in our current regulatory assets and liabilities driven by differences in fuel cost adjustments and commodity price impacts compared to the same period in the prior year;
- Cash outflows decreased by approximately $29 million as a result of a prior year interest rate swap settlement;
- Cash outflows increased by approximately $14 million due to additional pension contributions made in the current year;
- Cash outflows increased approximately $7.8 million for other operating activities compared to the prior year; and
- Cash inflows increased approximately $17 million due to operating activities of discontinued operations.

Investing Activities:

Net cash used in investing activities was $318 million in 2017, compared to net cash used in investing activities of $1.6 billion in 2016 for a variance of $1.3 billion. This variance was primarily due to:

- The prior year’s cash outflows included approximately $1.1 billion for the acquisition of SourceGas, net of $760 million long-term debt assumed (see Note 2 in Item 8 of Part II of this Annual Report on Form 10-K);
- Capital expenditures of approximately $326 million in 2017 compared to $455 million in 2016. The $129 million variance to the prior year was due primarily to higher prior year capital expenditures at our Electric Utilities from generation investments at Colorado Electric; and
- Cash inflows increased approximately $16 million due to investing activities of discontinued operations.

Financing Activities:

Net cash used in financing activities was $109 million in 2017, an increase of $950 million from 2016 primarily due to the following:

- Long-term borrowings decreased by $1.8 billion due to the 2016 financings which consisted of $693 million of net proceeds from the August 19, 2016 public debt offering used to refinance the debt assumed in the SourceGas Acquisition, $500 million of proceeds from the August 9, 2016 term loan, $546 million of net proceeds from our January 13, 2016 public debt offering used to partially finance the SourceGas Acquisition and proceeds from a $29 million term loan used to fund the early settlement of a gas gathering contract;

- Payments on long-term debt decreased by $1.1 billion due to the 2016 refinancing of the $760 million of long-term debt assumed in the SourceGas Acquisition and lower current year payments on term loans, $106 million paid on term loans in 2017 compared to $400 million paid on term loans in 2016;

- Proceeds of $216 million from the sale of a 49.9% noncontrolling interest of Black Hills Colorado IPP that took place in 2016 (see Note 12 in Item 8 of Part II of this Annual Report on Form 10-K);

- Proceeds from common stock issuances decreased by $117 million primarily from issuing common stock under our ATM equity offering program in 2016;

- Net short-term borrowings increased by $95 million primarily due to CP borrowings used to pay down long-term debt;

- Cash dividends on common stock of $97 million were paid in 2017 compared to $88 million paid in 2016;

- Distributions to noncontrolling interests increased by $8.8 million compared to prior year; and

- Cash outflows for other financing activities decreased by approximately $16 million driven primarily by higher financing costs incurred in the prior year from the 2016 debt offerings and refinancings compared to a payment of $5.6 million for a redeemable noncontrolling interest in March 2017.

2016 Compared to 2015

Operating Activities:

Net cash provided by operating activities was $104 million lower than in 2015 primarily attributable to the SourceGas acquisition and the following:

- Cash earnings (income from continuing operations plus non-cash adjustments) were $62 million higher than prior year.

- Net outflow from operating assets and liabilities was $59 million higher than prior year, primarily attributable to:

    - Cash outflows increased by approximately $66 million compared to the prior year as a result of higher materials, supplies and fuel and higher accounts receivable partially due to colder weather and higher natural gas volumes sold;

    - Cash outflows increased by approximately $34 million primarily as a result of changes in our current regulatory assets and liabilities driven by differences in fuel cost adjustments and commodity price impacts compared to the same period in the prior year;

    - Cash outflows decreased by approximately $42 million as a result of changes in accounts payable and accrued liabilities driven primarily by acquisition and transition costs, partially offset by an increase in accrued interest;

- Cash outflows increased by approximately $29 million as a result of interest rate swap settlements;

- Cash outflows increased by $4.0 million due to pension contributions;

- Cash outflows decreased approximately $8.4 million for other operating activities compared to the prior year; and

- Cash inflows decreased approximately $83 million due to operating activities of discontinued operations.

Investing Activities:

Net cash used in investing activities was $1.6 billion in 2016, which was an increase in outflows of $1.1 billion from 2015 primarily due to the following:

- Cash outflows of $1.1 billion for the acquisition of SourceGas, net of $11 million cash received from a working capital adjustment and $760 million of long term debt assumed (see Note 2 in Item 8 of Part II of this Annual Report on Form 10-K);

- In 2016, we had higher capital expenditures of $189 million primarily at our Electric Utilities and Gas Utilities, driven by 2016 wind and natural gas generation additions at our Electric Utilities, and additional capital at our acquired SourceGas Utilities;

- In 2015, we acquired the net assets of two natural gas utilities for $22 million; and

- Cash outflows decreased approximately $179 million due to investing activities of discontinued operations.

Financing Activities:

Net cash provided by financing activities was $841 million in 2016, an increase of $357 million from 2015 primarily due to the following:

- Proceeds of $216 million from the sale of a 49.9% noncontrolling interest of Black Hills Colorado IPP (see Note 12 in Item 8 of Part II of this Annual Report on Form 10-K);

- Long-term borrowings increased due to the $693 million of net proceeds from our August 19, 2016 public debt offering used to refinance the debt assumed in the SourceGas Acquisition, the $500 million of proceeds from our new term loan on August 9, 2016 used to pay off existing debt, the $546 million of net proceeds from our January 13, 2016 public debt offering used to partially finance the SourceGas Acquisition, and proceeds from a $29 million term loan used to fund the early settlement of a gas gathering contract, compared to proceeds of $300 million from long-term borrowings from a term loan in the prior year;

- Payments on long term borrowings increased due to payments made in the current year to refinance the $760 million of long-term debt assumed in the SourceGas Acquisition and $404 million of current year payments made on term loans compared to the payment of $275 million made as part of a term-loan refinancing in the prior year;

- In 2015, we received net proceeds of $290 million from the issuance of our RSNs;

- Proceeds of $120 million primarily from issuing common stock under our ATM equity offering program. 2015 included net proceeds from common stock issuances of $246 million;

- Net short-term borrowings under the revolving credit facility for the year ended December 31, 2016 were $18 million higher than the prior year primarily due to higher working capital requirements in the current year;

- Distributions to noncontrolling interests of $9.6 million;

- Cash outflows for other financing activities increased by approximately $14 million driven primarily by approximately $22 million of financing costs and make whole payments made in 2016 compared to $7 million of bridge facility fees paid in 2015; and

- Cash dividends on common stock of $88 million were paid in 2016 compared to $73 million paid in 2015.

CAPITAL EXPENDITURES

Capital expenditures are a substantial portion of our cash requirements each year and we continue to forecast a robust capital expenditure program during the next three years.

Historically, a significant portion of our capital expenditures relate primarily to assets that may be included in utility rate base, and if considered prudent by regulators, can be recovered from our utility customers. Those capital expenditures also earn a rate of return authorized by the commissions in the jurisdictions in which we operate and are subject to rate agreements. During 2017, our Electric Utilities' capital expenditures included improvements to generating stations, transmission and distribution lines. Capital expenditures associated with our Gas Utilities are primarily to improve or expand the existing gas distribution network. We believe that cash generated from operations and borrowing on our CP Program and our existing Revolving Credit Facility will be adequate to fund ongoing capital expenditures.

Historical Capital Requirements

Our primary capital requirements for the three years ended December 31 were as follows (in thousands):

	2017	2016	2015
Property additions: [(a)]			
Electric Utilities	$ 138,060	$ 258,739	$ 171,897
Gas Utilities	184,389	173,930	99,674
Power Generation	1,864	4,719	2,694
Mining	6,708	5,709	5,767
Corporate and Other	6,668	17,353	9,864
Capital expenditures before discontinued operations	337,689	460,450	289,896
Discontinued operations	23,222	6,669	168,925
Total capital expenditures	360,911	467,119	458,821
Common stock dividends	96,744	87,570	72,604
Maturities/redemptions of long-term debt	105,743	1,164,308	275,000
	$ 563,398	$ 1,718,997	$ 806,425

(a) Includes accruals for property, plant and equipment.

Forecasted Capital Expenditure Requirements

Our primary capital expenditure requirements for the three years ended December 31 are expected to be as follows (in thousands):

	2018	2019	2020
Electric Utilities	$ 149,000	$ 193,000	$ 141,000
Gas Utilities	263,000	279,000	245,000
Power Generation	2,000	14,000	5,000
Mining	7,000	7,000	7,000
Corporate and Other	10,000	13,000	8,000
	$ 431,000	$ 506,000	$ 406,000

We continue to evaluate potential future acquisitions and other growth opportunities which are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimates identified above.

CREDIT RATINGS AND COUNTERPARTIES

Financing for operational needs and capital expenditure requirements not satisfied by operating cash flows depends upon the cost and availability of external funds through both short and long-term financing. The inability to raise capital on favorable terms could negatively affect the Company's ability to maintain or expand its businesses. Access to funds is dependent upon factors such as general economic and capital market conditions, regulatory authorizations and policies, the Company's credit ratings, cash flows from routine operations and the credit ratings of counterparties. After assessing the current operating performance, liquidity and credit ratings of the Company, management believes that the Company will have access to the capital markets at prevailing market rates for companies with comparable credit ratings. BHC notes that credit ratings are not recommendations to buy, sell, or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency. Each rating should be evaluated independently of any other rating.

The following table represents the credit ratings, outlook and risk profile of BHC at December 31, 2017:

Rating Agency	Senior Unsecured Rating	Outlook
S&P [(a)]	BBB	Stable
Moody's [(b)]	Baa2	Stable
Fitch [(c)]	BBB+	Stable

(a) On July 21, 2017, S&P affirmed BBB rating and maintained a Stable outlook.
(b) On December 12, 2017, Moody's affirmed our Baa2 rating and maintained a Stable outlook.
(c) On October 4, 2017, Fitch affirmed BBB+ rating and maintained a Stable outlook.

Our fees and interest payments under various corporate debt agreements are based on the higher credit rating of S&P or Moody's. If either S&P or Moody's downgraded our senior unsecured debt, we may be required to pay additional fees and incur higher interest rates under current bank credit agreements.

The following table represents the credit ratings of South Dakota Electric at December 31, 2017:

Rating Agency	Senior Secured Rating
S&P	A-
Moody's	A1
Fitch	A

We do not have any trigger events (i.e., an acceleration of repayment of outstanding indebtedness, an increase in interest costs, or the posting of additional cash collateral) tied to our stock price and have not executed any transactions that require us to issue equity based on our credit ratings or other trigger events.

CONTRACTUAL OBLIGATIONS AND OTHER COMMITMENTS

Contractual Obligations

In addition to our capital expenditure programs, we have contractual obligations and other commitments that will need to be funded in the future. The following information summarizes our cash obligations and commercial commitments at December 31, 2017. Actual future obligations may differ materially from these estimated amounts (in thousands):

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	4-5 Years	After 5 Years
Long-term debt[(a)(b)]	$ 3,137,519	$ 5,743	$ 761,485	$ 8,436	$ 2,361,855
Unconditional purchase obligations[(c)]	819,635	149,526	253,357	207,717	209,035
Operating lease obligations[(d)]	15,638	5,030	5,797	1,726	3,085
Other long-term obligations[(e)]	52,024	—	—	—	52,024
Employee benefit plans[(f)]	195,524	18,778	58,564	39,391	78,791
Liability for unrecognized tax benefits in accordance with accounting guidance for uncertain tax positions	3,263	48	3,215	—	—
CP Program	211,300	211,300	—	—	—
Total contractual cash obligations[(g)]	$ 4,434,903	$ 390,425	$ 1,082,418	$ 257,270	$ 2,704,790

(a) Long-term debt amounts do not include discounts or premiums on debt.

(b) The following amounts are estimated for interest payments over the next five years based on a mid-year retirement date for long-term debt expiring during the identified period and are not included within the long-term debt balances presented: $127 million in 2018, $122 million in 2019, $113 million in 2020, $101 million in 2021 and $101 million in 2022. Estimated interest payments on variable rate debt are calculated by utilizing the applicable rates as of December 31, 2017.

(c) Unconditional purchase obligations include the energy and capacity costs associated with our PPAs, capacity and certain transmission, gas transportation and storage agreements The energy charges under the PPAs are variable costs, which for purposes of estimating our future obligations, were based on costs incurred during 2017 and price assumptions using existing prices at December 31, 2017. Our transmission obligations are based on filed tariffs as of December 31, 2017.

(d) Includes operating leases associated with several office buildings, warehouses and call centers, equipment and vehicles.

(e) Includes estimated asset retirement obligations associated with our Electric Utilities, Gas Utilities and Mining segments as discussed in Note 8 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

(f) Represents both estimated employer contributions to Defined Benefit Pension Plans and payments to employees for the Non-Pension Defined Benefit Postretirement Healthcare Plans and the Supplemental Non-Qualified Defined Benefit Plans through the year 2027.

(g) Amounts in the table exclude: (1) any obligation that may arise from our derivatives, including commodity related contracts that have a negative fair value at December 31, 2017. These amounts have been excluded as it is impractical to reasonably estimate the final amount and/or timing of any associated payments; and (2) a portion of our gas purchases are hedged. These hedges are in place to reduce our customers' underlying exposure to commodity price fluctuations. The impact of these hedges is not included in the above table.

Our Gas Utility segment has commitments to purchase physical quantities of natural gas under contracts indexed to various forward natural gas price curves. In addition, a portion of our gas purchases are purchased under evergreen contracts and therefore, for purposes of this disclosure, are carried out for 60 days. As of December 31, 2017, we are committed to purchase 11.2 million MMBtu, 10.6 million MMBtu, 3.9 million MMBtu, 3.7 million MMBtu and 1.8 million MMBtu in each of the years from 2018 to 2022, respectively.

Off-Balance Sheet Commitments

Guarantees

We have entered into various off-balance sheet commitments in the form of guarantees and letters of credit. We provide various guarantees supporting certain of our subsidiaries under specified agreements or transactions. At December 31, 2017, we had outstanding guarantees as indicated in the table below. For more information on these guarantees, see Note 20 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

We had the following guarantees in place (in thousands):

Nature of Guarantee	Outstanding at December 31, 2017	Year Expiring
Indemnification for subsidiary reclamation/surety bonds [(a)]	$ 58,221	Ongoing
	$ 58,221	

(a) We have guarantees in place for reclamation and surety bonds for our subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Consolidated Balance Sheets.

Letters of Credit

Letters of credit reduce the borrowing capacity available on our corporate Revolving Credit Facility. We had $27 million in letters of credit issued under our Revolving Credit Facility at December 31, 2017.

Market Risk Disclosures

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures.

Market risk is the potential loss that may occur as a result of an adverse change in market price or rate. We are exposed to the following market risks, including, but not limited to:

- Commodity price risk associated with our retail natural gas marketing activities and our fuel procurement for certain of our gas-fired generation assets; and
- Interest rate risk associated with our variable rate debt as described in Notes 6 and 7 of our Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Our exposure to these market risks is affected by a number of factors including the size, duration and composition of our energy portfolio, the absolute and relative levels of interest rates and commodity prices, the volatility of these prices and rates and the liquidity of the related interest rate and commodity markets.

The Black Hills Corporation Risk Policies and Procedures have been approved by our Executive Risk Committee and reviewed by the Audit Committee of our Board of Directors. These policies relate to numerous matters including governance, control infrastructure, authorized commodities and trading instruments, prohibited activities and employee conduct. The Executive Risk Committee, which includes senior level executives, meets on a regular basis to review our business and credit activities and to ensure that these activities are conducted within the authorized policies.

Electric and Gas Utilities

We produce, purchase and distribute power in four states, and purchase and distribute natural gas in six states. All of our utilities have GCA provisions that allow them to pass the prudently-incurred cost of gas through to the customer. To the extent that gas prices are higher or lower than amounts in our current billing rates, adjustments are made on a periodic basis to "true-up" billed amounts to match the actual natural gas cost we incurred. In South Dakota, Colorado, Wyoming and Montana, we have a mechanism for our regulated electric utilities that serves a purpose similar to the GCAs for our regulated gas utilities. To the extent that our fuel and purchased power costs are higher or lower than the energy cost built into our tariffs, the difference (or a portion thereof) is passed through to the customer. These adjustments are subject to periodic prudence reviews by the state utility commissions.

The operations of our utilities, including natural gas sold by our Gas Utilities and natural gas used by our Electric Utilities' generation plants or those plants under PPAs where our Electric Utilities must provide the generation fuel (tolling agreements) expose our utility customers to volatility in natural gas prices. Therefore, as allowed or required by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options, over-the-counter swaps and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP.

For our regulated utilities' hedging plans, unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Consolidated Balance Sheets in accordance with the state utility commission guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Consolidated Statements of Income (Loss).

We buy, sell and deliver natural gas at competitive prices by managing commodity price risk. As a result of these activities, this area of our business is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and/or sales during time frames ranging from January 2018 through May 2020.

The fair value of our Electric and Gas Utilities derivative contracts at December 31 is summarized below (in thousands):

	2017	2016
Net derivative liabilities	$ (6,644)	$ (4,733)
Cash collateral	8,256	12,722
	$ 1,612	$ 7,989

Wholesale Power

A potential risk related to power sales is the price risk arising from the sale of wholesale power that exceeds our generating capacity. These potential short positions can arise from unplanned plant outages or from unanticipated load demands. To manage such risk, we restrict wholesale off-system sales to amounts by which our anticipated generating capabilities and purchased power resources exceed our anticipated load requirements plus a required reserve margin.

Financing Activities

Historically, we have engaged in activities to manage risks associated with changes in interest rates. We utilized pay-fixed interest rate swap agreements to reduce exposure to interest rate fluctuations associated with floating rate debt obligations and anticipated debt refinancings. At December 31, 2017, we had no interest rate swaps in place. At December 31, 2016, we had a $50 million notional, 4.94% pay-fixed interest rate swap designated to borrowings on our Revolving Credit Facility; this swap expired in January 2017.

Further details of past swap agreements are set forth in Note 9 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K.

The table below presents principal amounts and related weighted average interest rates by year of maturity for our long-term debt obligations, including current maturities (dollars in thousands):

	2018	2019	2020	2021	2022	Thereafter	Total
Long-term debt							
Fixed rate[a]	$ 5,743	$ 255,742	$ 205,743	$ 1,436	$ —	$ 2,349,000	$ 2,817,664
Average interest rate [b]	2.32%	2.5%	5.78%	2.32%	—%	4.29%	4.23%
Variable rate	$ —	$ 300,000	$ —	$ 7,000	$ —	$ 12,855	$ 319,855
Average interest rate [b]	—%	2.55%	—%	1.78%	—%	1.79%	2.5%
Total long-term debt	$ 5,743	$ 555,742	$ 205,743	$ 8,436	$ —	$ 2,361,855	$ 3,137,519
Average interest rate [b]	2.32%	2.53%	5.78%	1.87%	—%	4.28%	4.05%

(a) Excludes unamortized premium or discount.
(b) The average interest rates do not include the effect of interest rate swaps.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty. We have adopted the Black Hills Corporation Credit Policy that establishes guidelines, controls and limits to manage and mitigate credit risk within risk tolerances established by the Board of Directors. In addition, our Executive Risk Committee, which includes senior executives, meets on a regular basis to review our credit activities and to monitor compliance with the adopted policies.

We seek to mitigate our credit risk by conducting a majority of our business with investment grade companies, setting tenor and credit limits commensurate with counterparty financial strength, obtaining netting agreements and securing our credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by our review of their current credit information. We maintain a provision for estimated credit losses based upon our historical experience and any specific customer collection issue that we have identified. While most credit losses have historically been within our expectations and provisions established, we cannot provide assurance that we will continue to experience the same credit loss rates that we have in the past, or that an investment grade counterparty will not default sometime in the future.

Our credit exposure at December 31, 2017 was concentrated primarily among retail utility customers, investment grade companies, municipal cooperatives and federal agencies.

New Accounting Pronouncements

See Note 1 of the Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K for information on new accounting standards adopted in 2017 or pending adoption.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Management’s Report on Internal Control over Financial Reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2017, based on the criteria set forth in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission “COSO”. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on our evaluation, we have concluded that our internal control over financial reporting was effective as of December 31, 2017.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Black Hills Corporation’s financial statements, has issued an attestation report on the effectiveness of Black Hills Corporation's internal control over financial reporting as of December 31, 2017. Deloitte & Touche LLP's report on Black Hills Corporation's internal control over financial reporting is included herein.

Black Hills Corporation

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Black Hills Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income (loss), comprehensive income (loss), equity, and cash flows for each of the three years in the period ended December 31, 2017, the related notes, and the schedule listed in the Index at Item 15 (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2018, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota

February 23, 2018

We have served as the Company’s auditor since 2002.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Black Hills Corporation

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Black Hills Corporation and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2017, of the Company, and our report dated February 23, 2018 expressed an unqualified opinion on those consolidated financial statements and financial statement schedule.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

Minneapolis, Minnesota

February 23, 2018

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME (LOSS)

Year ended	December 31, 2017	December 31, 2016	December 31, 2015
	(in thousands, except per share amounts)		
Revenue	$ 1,680,266	$ 1,538,916	$ 1,261,322
Operating expenses:			
Fuel, purchased power and cost of natural gas sold	563,288	499,132	456,887
Operations and maintenance	454,605	426,603	323,809
Depreciation, depletion and amortization	188,246	175,533	126,533
Taxes - property and production	51,578	46,160	40,060
Other operating expenses	5,813	55,307	13,613
Total operating expenses	1,263,530	1,202,735	960,902
Operating income	416,736	336,181	300,420
Other income (expense):			
Interest charges -			
Interest expense incurred (including amortization of debt issuance costs, premiums and discounts)	(140,756)	(139,447)	(86,226)
Allowance for funds used during construction - borrowed	2,415	2,981	1,250
Capitalized interest	223	356	326
Interest income	1,016	1,429	1,621
Allowance for funds used during construction - equity	2,321	3,270	897
Other expense	(1,559)	(626)	(158)
Other income	1,346	1,750	2,075
Total other income (expense)	(134,994)	(130,287)	(80,215)
Income before income taxes	281,742	205,894	220,205
Income tax benefit (expense)	(73,367)	(59,101)	(78,657)
Income from continuing operations	208,375	146,793	141,548
Net (loss) from discontinued operations	(17,099)	(64,162)	(173,659)
Net income (loss)	191,276	82,631	(32,111)
Net income attributable to noncontrolling interest	(14,242)	(9,661)	—
Net income (loss) available for common stock	$ 177,034	$ 72,970	$ (32,111)
Amounts attributable to common shareholders:			
Net income from continuing operations	$ 194,133	$ 137,132	$ 141,548
Net (loss) from discontinued operations	(17,099)	(64,162)	(173,659)
Net income (loss) available for common stock	$ 177,034	$ 72,970	$ (32,111)
Earnings (loss) per share of common stock, Basic -			
Earnings from continuing operations	$ 3.65	$ 2.64	$ 3.12
(Loss) from discontinued operations	$ (0.32)	$ (1.23)	$ (3.83)
Total earnings (loss) per share of common stock, Basic	$ 3.33	$ 1.41	$ (0.71)
Earnings (loss) per share of common stock, Diluted -			
Earnings from continuing operations	$ 3.52	$ 2.57	$ 3.12
(Loss) from discontinued operations	$ (0.31)	$ (1.20)	$ (3.83)

Total earnings (loss) per share of common stock, Diluted	$ 3.21	$ 1.37	$ (0.71)
Weighted average common shares outstanding:			
Basic	53,221	51,922	45,288
Diluted	55,120	53,271	45,288

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

Year ended	December 31, 2017	December 31, 2016	December 31, 2015
		(in thousands)	
Net income (loss)	$ 191,276	$ 82,631	$ (32,111)
Other comprehensive income (loss), net of tax:			
Benefit plan liability adjustments - net gain (loss) (net of tax of $1,030, $757 and $(1,375), respectively)	(1,890)	(1,738)	2,657
Benefit plan liability adjustments - prior service (costs) (net of tax of $0, $107 and $0, respectively)	—	(247)	—
Reclassification adjustment of benefit plan liability - net gain (loss) (net of tax of $(585), $(600) and $(972), respectively)	1,072	1,378	1,850
Reclassification adjustment of benefit plan liability - prior service cost (net of tax of $69, $67 and $88, respectively)	(128)	(154)	(150)
Derivative instruments designated as cash flow hedges:			
Net unrealized gains (losses) on interest rate swaps (net of tax of $0, $10,920 and $(598), respectively)	—	(20,302)	2,290
Reclassification of net realized (gains) losses on settled/amortized interest rate swaps (net of tax of $(1,029), $(1,365) and $(1,348), respectively)	1,912	2,534	2,299
Net unrealized gains (losses) on commodity derivatives (net of tax of $(135), $212 and $(3,898), respectively)	231	(361)	5,884
Reclassification of net realized (gains) losses on settled commodity derivatives (net of tax of $154, $4,067 and $5,619, respectively)	(516)	(6,938)	(8,841)
Other comprehensive income (loss), net of tax	681	(25,828)	5,989
Comprehensive income (loss)	191,957	56,803	(26,122)
Less: comprehensive income attributable to non-controlling interest	(14,242)	(9,661)	—
Comprehensive income (loss) available for common stock	$ 177,715	$ 47,142	$ (26,122)

See Note 16 for additional disclosures related to Comprehensive Income.

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS

	As of	
	December 31, 2017	December 31, 2016
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 15,420	$ 13,518
Restricted cash and equivalents	2,820	2,274
Accounts receivable, net	248,330	259,311
Materials, supplies and fuel	113,283	103,606
Derivative assets, current	304	3,985
Regulatory assets, current	81,016	49,260
Other current assets	25,367	23,928
Current assets held for sale	84,242	10,932
Total current assets	570,782	466,814
Investments	13,090	12,561
Property, plant and equipment	5,567,518	5,315,296
Less accumulated depreciation and depletion	(1,026,088)	(929,119)
Total property, plant and equipment, net	4,541,430	4,386,177
Other assets:		
Goodwill	1,299,454	1,299,454
Intangible assets, net	7,559	8,392
Derivative assets, non-current	—	222
Regulatory assets, non-current	216,438	246,882
Other assets, non-current	10,149	11,508
Noncurrent assets held for sale	—	109,763
Total other assets, non-current	1,533,600	1,676,221
TOTAL ASSETS	$ 6,658,902	$ 6,541,773

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED BALANCE SHEETS
(Continued)

	As of	
	December 31, 2017	December 31, 2016
	(in thousands, except share amounts)	
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND EQUITY		
Current liabilities:		
Accounts payable	$ 160,887	$ 152,129
Accrued liabilities	219,462	235,548
Derivative liabilities, current	2,081	1,104
Accrued income tax, net	1,022	12,552
Regulatory liabilities, current	6,832	13,067
Notes payable	211,300	96,600
Current maturities of long-term debt	5,743	5,743
Current liabilities held for sale	41,774	11,189
Total current liabilities	649,101	527,932
Long-term debt, net of current maturities	3,109,400	3,211,189
Deferred credits and other liabilities:		
Deferred income tax liabilities, net	336,520	561,935
Regulatory liabilities, non-current	478,294	193,689
Benefit plan liabilities	159,646	173,682
Other deferred credits and other liabilities	105,735	115,883
Noncurrent liabilities held for sale	—	23,034
Total deferred credits and other liabilities	1,080,195	1,068,223
Commitments and contingencies (See Notes 6, 7, 8, 9, 14, 18, 19, and 20)		
Redeemable noncontrolling interest	—	4,295
Equity:		
Stockholders' equity -		
Common stock $1 par value; 100,000,000 shares authorized; issued: 53,579,986 and 53,397,467, respectively	53,580	53,397
Additional paid-in capital	1,150,285	1,138,982
Retained earnings	548,617	457,934
Treasury stock at cost - 39,064 and 15,258, respectively	(2,306)	(791)
Accumulated other comprehensive income (loss)	(41,202)	(34,883)
Total stockholders' equity	1,708,974	1,614,639
Noncontrolling interest	111,232	115,495
Total equity	1,820,206	1,730,134
TOTAL LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND TOTAL EQUITY	$ 6,658,902	$ 6,541,773

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended	December 31, 2017	December 31, 2016	December 31, 2015
		(in thousands)	
Operating activities:			
Net income (loss)	$ 191,276	$ 82,631	$ (32,111)
(Income) loss from discontinued operations, net of tax	17,099	64,162	173,659
Income (loss) from continuing operations	208,375	146,793	141,548
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	188,246	175,533	126,533
Deferred financing cost amortization	8,261	6,180	6,364
Stock compensation	7,626	10,885	4,076
Deferred income taxes	80,992	82,704	74,704
Employee benefit plans	10,141	14,291	20,616
Other adjustments, net	(4,773)	(5,519)	(4,872)
Change in certain operating assets and liabilities:			
Materials, supplies and fuel	(10,089)	1,211	7,216
Accounts receivable, unbilled revenues and other current assets	4,534	(27,172)	33,255
Accounts payable and other current liabilities	(28,222)	(33,023)	(74,748)
Regulatory assets	(15,407)	3,614	21,883
Regulatory liabilities	(4,536)	(14,082)	1,675
Contributions to defined benefit pension plans	(27,700)	(14,200)	(10,200)
Interest rate swap settlement	—	(28,820)	—
Other operating activities, net	(8,418)	(660)	(9,033)
Net cash provided by operating activities of continuing operations	409,030	317,735	339,017
Net cash provided by (used in) operating activities of discontinued operations	19,231	2,744	85,366
Net cash provided by operating activities	428,261	320,479	424,383
Investing activities:			
Property, plant and equipment additions	(326,010)	(454,952)	(266,375)
Acquisition of net assets, net of long-term debt assumed	—	(1,124,238)	(21,970)
Other investing activities	465	(1,139)	(444)
Net cash (used in) investing activities of continuing operations	(325,545)	(1,580,329)	(288,789)
Net cash provided by (used in) investing activities of discontinued operations	7,881	(8,413)	(187,600)
Net cash provided by (used in) investing activities	(317,664)	(1,588,742)	(476,389)
Financing activities:			
Dividends paid on common stock	(96,744)	(87,570)	(72,604)
Common stock issued	4,408	121,619	248,759
Net increase (decrease) in commercial paper and short-term borrowings	114,700	19,800	1,800
Long-term debt - issuance	—	1,767,608	300,000
Long-term debt - repayments	(105,743)	(1,164,308)	(275,000)
Sale of noncontrolling interest	—	216,370	—
Distributions to noncontrolling interests	(18,397)	(9,561)	—
Equity units - issuance	—	—	290,030
Other financing activities	(6,919)	(22,960)	(9,283)
Net cash provided by (used in) financing activities	(108,695)	840,998	483,702
Net change in cash and cash equivalents	1,902	(427,265)	431,696

Cash and cash equivalents beginning of year	13,518	440,783	9,087
Cash and cash equivalents end of year	$ 15,420	$ 13,518	$ 440,783

See Note 17 for supplemental disclosure of cash flow information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY

(in thousands except share amounts)	Common Stock Shares	Common Stock Value	Treasury Stock Shares	Treasury Stock Value	Additional Paid in Capital	Retained Earnings	AOCI	Non controlling Interest	Total
Balance at December 31, 2014	44,714,072	$ 44,714	42,226	$ (1,875)	$ 748,840	$ 577,249	$ (15,044)	$ —	$ 1,353,884
Net income (loss) available for common stock	—	—	—	—	—	(32,111)	—	—	(32,111)
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	5,989	—	5,989
Dividends on common stock	—	—	—	—	—	(72,604)	—	—	(72,604)
Share-based compensation	126,765	127	(2,506)	(13)	4,126	—	—	—	4,240
Issuance of common stock	6,325,000	6,325	—	—	248,256	—	—	—	254,581
Issuance costs	—	—	—	—	(17,926)	—	—	—	(17,926)
Premium on Equity Units	—	—	—	—	(33,118)	—	—	—	(33,118)
Dividend reinvestment and stock purchase plan	66,024	66	—	—	2,891	—	—	—	2,957
Other stock transactions	—	—	—	—	(25)	—	—	—	(25)
Balance at December 31, 2015	51,231,861	$ 51,232	39,720	$ (1,888)	$ 953,044	$ 472,534	$ (9,055)	$ —	$ 1,465,867
Net income (loss) available for common stock	—	—	—	—	—	72,970	—	9,661	82,631
Other comprehensive income (loss), net of tax	—	—	—	—	—	—	(25,828)	—	(25,828)
Dividends on common stock	—	—	—	—	—	(87,570)	—	—	(87,570)
Share-based compensation	145,634	146	(16,165)	668	4,665	—	—	—	5,479
Issuance of common stock	1,968,738	1,969	—	—	118,021	—	—	—	119,990
Issuance costs	—	—	—	—	(1,566)	—	—	—	(1,566)
Dividend reinvestment and stock purchase plan	51,234	50	—	—	2,933	—	—	—	2,983
Other stock transactions	—	—	(8,297)	429	47	—	—	—	476
Sale of noncontrolling interest	—	—	—	—	61,838	—	—	115,395	177,233
Distributions to noncontrolling interest	—	—	—	—	—	—	—	(9,561)	(9,561)
Balance at December 31, 2016	53,397,467	$ 53,397	15,258	$ (791)	$ 1,138,982	$ 457,934	$ (34,883)	$ 115,495	$ 1,730,134
Net income (loss) available for common stock	—	—	—	—	—	177,034	—	14,242	191,276
Other comprehensive income (loss), net of tax	—	—	—	—	—		681	—	681
Reclassification of certain tax effects from AOCI	—	—	—	—	—	7,000	(7,000)	—	—
Dividends on common stock	—	—	—	—	—	(96,744)	—	—	(96,744)
Share-based compensation	134,266	134	23,806	(1,515)	8,948	—	—	—	7,567
Tax effect of share-based compensation	—	—	—	—	533	3,184	—	—	3,717
Issuance costs	—	—	—	—	(189)	—	—	—	(189)
Dividend reinvestment and stock purchase plan	48,253	49	—	—	3,107	—	—	—	3,156
Redemption of and distributions to noncontrolling interest	—	—	—	—	(1,096)	209	—	(18,505)	(19,392)
Balance at December 31, 2017	53,579,986	$ 53,580	39,064	$ (2,306)	$ 1,150,285	$ 548,617	$ (41,202)	$ 111,232	$ 1,820,206

Dividends per share paid were $1.81, $1.68 and $1.62 for the years ended December 31, 2017, 2016 and 2015, respectively.

The accompanying Notes to Consolidated Financial Statements are an integral part of these Consolidated Financial Statements.

BLACK HILLS CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2017, 2016 and 2015

(1) BUSINESS DESCRIPTION AND SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Corporation is a customer-focused, growth-oriented, vertically-integrated utility company headquartered in Rapid City, South Dakota. We are a holding company that, through our subsidiaries, conducts our operations through the following reportable segments: Electric Utilities, Gas Utilities, Power Generation and Mining. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other.

Segment Reporting

Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation. All of our operations and assets are located within the United States.

Our Electric Utilities segment includes the operating results of the regulated electric utility operations of South Dakota Electric, Wyoming Electric and Colorado Electric, which supply regulated electric utility services to areas in South Dakota, Wyoming, Colorado and Montana. Our Gas Utilities Segment consists of the operating results of our regulated natural gas utility subsidiaries in Arkansas, Colorado, Iowa, Kansas, Wyoming and Nebraska.

All of our non-utility business segments support our electric utilities. Our Power Generation segment, which is conducted through Black Hills Electric Generation and its subsidiaries, engages in independent power generation activities in Wyoming and Colorado. Our Mining segment, which is conducted through WRDC, engages in coal mining activities located near Gillette, Wyoming. For further descriptions of our reportable business segments, see Note 5.

On November 1, 2017, our Board of Directors approved a complete divestiture of our Oil and Gas segment. As of February 23, 2018, we have either closed transactions or signed contracts to sell more than 90% of our oil and gas properties. We have executed agreements to sell all our operated properties and have only non-operated assets left to divest. We plan to conclude the sale of all of our remaining assets by mid-year 2018.

The Oil and Gas segment assets and liabilities have been classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. The consolidated financial statements and accompanying notes for current and prior periods have been restated. At the time the assets were classified as held for sale, depreciation, depletion and amortization expenses were no longer recorded. Unless otherwise noted, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company’s continuing operations. For more information on discontinued operations, see Note 21.

Use of Estimates and Basis of Presentation

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Changes in facts and circumstances or additional information may result in revised estimates and actual results could differ materially from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of Black Hills Corporation and its wholly-owned and majority-owned and controlled subsidiaries. Investment in non-controlled entities over which we have the ability to exercise significant influence over operating and financial policies are accounted for using the equity method of accounting. In applying the equity method of accounting, the investments are initially recognized at cost and subsequently adjusted for our proportionate share of earnings and losses and distributions. Under this method, a proportionate share of pretax income is recorded as Equity earnings (loss) of unconsolidated subsidiaries. All intercompany balances and transactions have been eliminated in consolidation. For additional information on intercompany revenues, see Note 5.

Our Consolidated Statements of Income (Loss) include operating activity of acquired companies beginning with their acquisition date. We use the proportionate consolidation method to account for our working interests in oil and gas properties and for our ownership interest in any jointly-owned electric utility generating facility, wind project or transmission tie. See Note 4 for additional information.

Variable Interest Entities

We evaluate arrangements and contracts with other entities to determine if they are VIEs and if so, if we are the primary beneficiary. GAAP provides a framework for identifying VIEs and determining when a company should include the assets, liabilities, noncontrolling interest and results of activities of a VIE in its consolidated financial statements.

A VIE should be consolidated if a party with an ownership, contractual or other financial interest in the VIE (a variable interest holder) has the power to direct the VIE's most significant activities and the obligation to absorb losses or right to receive benefits of the VIE that could be significant to the VIE. A variable interest holder that consolidates the VIE is called the primary beneficiary. Upon consolidation, the primary beneficiary generally must initially record all of the VIE's assets, liabilities and noncontrolling interests at fair value and subsequently account for the VIE as if it were consolidated.

Our evaluation of whether our interest qualifies as the primary beneficiary of a VIE involves significant judgments, estimates and assumptions and includes a qualitative analysis of the activities that most significantly impact the VIE's economic performance and whether the Company has the power to direct those activities, the design of the entity, the rights of the parties and the purpose of the arrangement. Black Hills Colorado IPP is a VIE. See additional information in Note 12.

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Equivalents

We maintain cash accounts for various specified purposes. Therefore, we classify these amounts as restricted cash.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable for our Electric and Gas Utilities business segments primarily consists of sales to residential, commercial, industrial, municipal and other customers, all of which do not bear interest. These accounts receivable are stated at billed and estimated unbilled amounts net of write-offs and allowance for doubtful accounts. Accounts receivable for our Mining and Power Generation business segments consists of amounts due from sales of coal, natural gas, electric energy and capacity.

We maintain an allowance for doubtful accounts which reflects our estimate of uncollectible trade receivables. We regularly review our trade receivable allowance by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect collectibility.

In specific cases where we are aware of a customer's inability or reluctance to pay, we record an allowance for doubtful accounts to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of commodity prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible or the time allowed for dispute under the contract has expired.

We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty.

Following is a summary of accounts receivable as of December 31 (in thousands):

2017	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 39,347	$ 36,384	$ (586)	$ 75,145
Gas Utilities	81,256	88,967	(2,495)	167,728
Power Generation	1,196	—	—	1,196
Mining	2,804	—	—	2,804
Corporate	1,457	—	—	1,457
Total	$ 126,060	$ 125,351	$ (3,081)	$ 248,330

2016	Accounts Receivable, Trade	Unbilled Revenue	Less Allowance for Doubtful Accounts	Accounts Receivable, net
Electric Utilities	$ 41,730	$ 36,463	$ (353)	$ 77,840
Gas Utilities	88,168	88,329	(2,026)	174,471
Power Generation	1,420	—	—	1,420
Mining	3,352	—	—	3,352
Corporate	2,228	—	—	2,228
Total	$ 136,898	$ 124,792	$ (2,379)	$ 259,311

Revenue Recognition

Revenue is recognized when there is persuasive evidence of an arrangement with a fixed or determinable price and delivery has occurred or services have been rendered. Sales and franchise taxes collected from our customers are recorded on a net basis (excluded from Revenue).

Utility revenues are based on authorized rates approved by the state regulatory agencies and the FERC. Revenues related to the sale, transmission and distribution of energy, and delivery of service are generally recorded when service is rendered or energy is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, our utilities accrue an estimate of the revenue since the latest billing. This estimate is calculated based upon several factors including billings through the last billing cycle in a month and prices in effect in our jurisdictions. Each month the estimated unbilled revenue amounts are trued-up and recorded in Accounts receivable, net on the accompanying Consolidated Balance Sheets.

For long-term non-regulated power sales agreements, revenue is recognized either in accordance with accounting standards for revenue recognition, or in accordance with accounting standards for leases, as appropriate. Under accounting standards for revenue recognition, revenue is generally recognized as the lesser of the amount billed or the average rate expected over the life of the agreement.

Natural gas and crude oil sales included in discontinued operations are recognized when the products are sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectibility of the revenue is reasonably assured. BHEP records its share of revenues based on production volumes and contracted sales prices. The sales price for natural gas, crude oil, condensate and NGLs is adjusted for transportation costs and other related deductions when applicable. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment.

Materials, Supplies and Fuel

The following amounts by major classification are included in Materials, supplies and fuel on the accompanying Consolidated Balance Sheets as of December 31 (in thousands):

	2017	2016
Materials and supplies	$ 69,732	$ 64,852
Fuel - Electric Utilities	2,962	3,667
Natural gas in storage	40,589	35,087
Total materials, supplies and fuel	$ 113,283	$ 103,606

Materials and supplies represent parts and supplies for all of our business segments. Fuel - Electric Utilities represents oil, gas and coal on hand used to produce power. Natural gas in storage primarily represents gas purchased for use by our gas customers. All of our Materials, supplies and fuel are recorded using the weighted-average cost method and are valued at the lower-of-cost or net realizable value. The value of our natural gas in storage fluctuates with seasonal volume requirements of our business and the commodity price of natural gas.

Accrued Liabilities

The following amounts by major classification are included in Accrued liabilities on the accompanying Consolidated Balance Sheets as of December 31 (in thousands):

	2017	2016
Accrued employee compensation, benefits and withholdings	$ 52,467	$ 54,553
Accrued property taxes	42,029	37,379
Customer deposits and prepayments	44,420	55,191
Accrued interest	33,822	33,982
CIAC current portion	1,552	1,575
Other (none of which is individually significant)	45,172	52,868
Total accrued liabilities	$ 219,462	$ 235,548

Property, Plant and Equipment

Additions to property, plant and equipment are recorded at cost. Included in the cost of regulated construction projects is AFUDC, when applicable, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a regulated utility project. We also capitalize interest, when applicable, on undeveloped leasehold costs and certain non-regulated construction projects. In addition, asset retirement costs associated with tangible long-lived regulated utility assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived regulated utility assets in the period incurred. The amounts capitalized are included in Property, plant and equipment on the accompanying Consolidated Balance Sheets. We also classify our base or “cushion gas” as property, plant and equipment. Cushion gas is the portion of natural gas necessary to force saleable gas from a storage field into the transmission system and for system balancing, representing a permanent investment necessary to use storage facilities and maintain reliability.

The cost of regulated utility property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage plus retirement costs, is charged to accumulated depreciation. Estimated removal costs associated with non-legal retirement obligations related to our regulated properties are reclassified from accumulated depreciation and reflected as regulatory liabilities. Retirement or disposal of all other assets, except for crude oil and natural gas properties as described below, result in gains or losses recognized as a component of operating income. Ordinary repairs and maintenance of property, except as allowed under rate regulations, are charged to operations as incurred.

Depreciation provisions for property, plant and equipment are generally computed on a straight-line basis based on the applicable estimated service life of the various classes of property. Capitalized coal mining costs and coal leases are amortized on a unit-of-production method based on volumes produced and estimated reserves. For certain non-utility power plant components, depreciation is computed on a unit-of-production methodology based on plant hours run.

Goodwill and Intangible Assets

Goodwill and intangible assets with indefinite lives are not amortized, but the carrying values are reviewed upon an indicator of impairment or at least annually. Intangible assets with a finite life continue to be amortized over their estimated useful lives.

We perform a goodwill impairment test on an annual basis or upon the occurrence of events or changes in circumstances that indicate that the asset might be impaired. Beginning in 2016, we changed our annual goodwill impairment testing date from November 30 to October 1 to better align the testing date with our financial planning process. We believe that the change in the date of the annual goodwill impairment test from November 30 to October 1 is not a material change in the application of an accounting principle. The new and old testing dates are close in proximity and both are in the fourth quarter of the year. We would not expect a materially different outcome as a result of testing on October 1 as compared to November 30. The change in assessment date does not have a material effect on the financial statements.

We estimated the fair value of the goodwill using discounted cash flow methodology, EBITDA multiple method and an analysis of comparable transactions. This analysis required the input of several critical assumptions, including future growth rates, cash flow projections, operating cost escalation rates, rates of return, a risk-adjusted discount rate, timing and level of success in regulatory rate proceedings, the cost of debt and equity capital and long-term earnings and merger multiples for comparable companies.

The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. See Note 5 for additional business segment information.

Goodwill at our Electric Utilities primarily arose from Colorado Electric, acquired in the Aquila acquisition, which allocated approximately $246 million, or 72% of the transaction to Colorado Electric. Goodwill at our Gas Utilities is primarily from the SourceGas Acquisition, which was allocated entirely to the Gas Utilities adding $940 million in goodwill and the Aquila Transaction, which allocated approximately $94 million, or 28% of the transaction, to the Gas Utilities.

We believe that the goodwill reflects the inherent value of the relatively stable, long-lived cash flows of the regulated electric and gas utility businesses, considering the regulatory environment, and the long-lived cash flow and rate base growth opportunities at our utilities. Goodwill balances were as follows (in thousands):

	Electric Utilities	Gas Utilities	Power Generation	Total
Ending balance at December 31, 2015	$ 248,479	$ 102,515	$ 8,765	$ 359,759
Additions [(a)]	—	939,695	—	939,695
Ending balance at December 31, 2016	$ 248,479	$ 1,042,210	$ 8,765	$ 1,299,454
Additions	—	—	—	—
Ending balance at December 31, 2017	$ 248,479	$ 1,042,210	$ 8,765	$ 1,299,454

(a) Represents goodwill recorded with the acquisition of SourceGas. See Note 2 for more information.

Our intangible assets represent easements, rights-of-way, customer listings and trademarks. The finite-lived intangible assets are amortized using a straight-line method based on estimated useful lives; these assets are currently being amortized from 2 years to 40 years. Changes to intangible assets for the years ended December 31, were as follows (in thousands):

	2017	2016	2015
Intangible assets, net, beginning balance	$ 8,392	$ 3,380	$ 3,176
Additions	—	5,522	434
Amortization expense [(a)]	(833)	(510)	(230)
Intangible assets, net, ending balance	$ 7,559	$ 8,392	$ 3,380

(a) Amortization expense for existing intangible assets is expected to be $0.8 million for each year of the next five years.

Asset Retirement Obligations

Accounting standards for asset retirement obligations associated with long-lived assets require that the present value of retirement costs for which we have a legal obligation be recorded as liabilities with an equivalent amount added to the asset cost and depreciated over an appropriate period. The associated ARO accretion expense for our non-regulated operations is included within Depreciation, depletion and amortization on the accompanying Consolidated Statements of Income (Loss). The accounting for the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset or a regulatory liability.

We initially record liabilities for the present value of retirement costs for which we have a legal obligation, with an equivalent amount added to the asset cost. The asset is then depreciated or depleted over the appropriate useful life and the liability is accreted over time by applying an interest method of allocation. Any difference in the actual cost of the settlement of the liability and the recorded amount is recognized as a gain or loss in the results of operations at the time of settlement for our non-regulated operations. For oil and gas liabilities classified as held for sale, differences in the settlement of the liability and the recorded amount are generally reflected as adjustments to the capitalized cost of oil and gas properties and prior to held-for-sale classification were depleted pursuant to the use of the full cost method of accounting. Additional information is included in Note 8 and 21.

Fair Value Measurements

Derivative Financial Instruments

Assets and liabilities are classified and disclosed in one of the following fair value categories:

Level 1 — Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities. This level primarily consists of financial instruments such as exchange-traded securities or listed derivatives.

Level 2 — Pricing inputs include quoted prices for identical or similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 — Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs reflect management’s best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable such as the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

Valuation Methodologies for Derivatives

Electric Utilities and Gas Utilities Segments:

- The commodity contracts for the Electric and Gas Utilities, valued using the market approach, include exchange-traded futures, options, basis swaps and over-the-counter swaps (Level 2) for natural gas contracts. For exchanged-traded futures, options and basis swap Level 2 assets and liabilities, fair value was derived using broker quotes validated by the Chicago Mercantile Exchange pricing for similar instruments. For over-the-counter swaps and option Level 2 assets and liabilities, fair value was derived from, or corroborated by, observable market pricing data. In addition, the fair value for the over-the-counter swaps and option derivatives include a CVA component. The CVA considers the fair value of the derivative and the probability of default based on the life of the contract. For the probability of a default component, we utilize observable inputs supporting Level 2 disclosure by using our credit default spread, if available, or a generic credit default spread curve that takes into account our credit ratings.

Corporate Segment:

- Interest rate swaps are valued using the market valuation approach. We establish fair value by obtaining price quotes directly from the counterparty which are based on the floating three-month LIBOR curve for the term of the contract. The fair value obtained from the counterparty is then validated by utilizing a nationally recognized service that obtains observable inputs to compute fair value for the same instrument. In addition, the fair value for the interest rate swap derivatives includes a CVA component. The CVA considers the fair value of the interest rate swap and the probability of default based on the life of the contract. For the probability of a default component, we utilize observable inputs supporting Level 2 disclosure by using our credit default spread, if available, or a generic credit default spread curve that takes into account our credit ratings. We have no interest rate swaps as of December 31, 2017.

Additional information is included in Note 10.

Derivatives and Hedging Activities

The accounting standards for derivatives and hedging require that derivative instruments be recorded on the balance sheet as either an asset or liability measured at its fair value and changes in the derivative instrument’s fair value be recognized currently in earnings unless specific hedge accounting criteria are met and designated accordingly, if they qualify for certain exemptions, including the normal purchases and normal sales exemption, or if regulatory rulings require a different accounting treatment. Changes in the fair value for derivative instruments that do not meet any of these criteria are recognized in the income statement as they occur. Each Consolidated Balance Sheet reflects the offsetting of net derivative positions with fair value amounts for cash collateral with the same counterparty when a legal right of offset exists.

Revenues and expenses on contracts that qualify as derivatives may be elected under the normal purchases and normal sales exception and are recognized when the underlying physical transaction is completed under the accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable amount of time, and price is not tied to an unrelated underlying derivative. As part of our electric and gas utility operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it was determined that a transaction designated as a normal purchase or normal sale no longer met the exceptions, the fair value of the related contract would be reflected as either an asset or liability, under the accounting standards for derivatives and hedging.

We utilize master netting agreements which consist of an agreement between two parties who have multiple contracts with each other that provide for the net settlement of all contracts in the event of default on or termination of any one contract. When the right of offset exists, accounting standards permit the netting of receivables and payables under a legally enforceable master netting agreement between counterparties. Accounting standards also permit offsetting of fair value amounts recognized for the right to reclaim, or the obligation to return, cash collateral against fair value amounts recognized for derivative instruments executed with the same counterparty.

Deferred Financing Costs

Deferred financing costs are amortized over the estimated useful life of the related debt. Deferred financing costs are presented on the balance sheet as an adjustment to the related debt liabilities.

Regulatory Accounting

Our Electric Utilities and Gas Utilities follow accounting standards for regulated operations and reflect the effects of the numerous rate-making principles followed by the various state and federal agencies regulating the utilities. The accounting policies followed are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by our non-regulated businesses. If rate recovery becomes unlikely or uncertain due to competition or regulatory action, these accounting standards may no longer apply which could require these net regulatory assets to be charged to current income or OCI. Our regulatory assets represent amounts for which we will recover the cost, but generally are not allowed a return, except as described below. In the event we determine that our regulated net assets no longer meet the criteria for accounting standards for regulated operations, the accounting impact to us could be an extraordinary non-cash charge to operations, which could be material.

We had the following regulatory assets and liabilities as of December 31 (in thousands):

	Maximum Amortization (in years)	2017	2016
Regulatory assets			
Deferred energy and fuel cost adjustments - current [a]	1	$ 20,187	$ 17,491
Deferred gas cost adjustments [a]	1	31,844	15,329
Gas price derivatives [a]	3	11,935	8,843
Deferred taxes on AFUDC [b]	45	7,847	15,227
Employee benefit plans [c]	12	109,235	108,556
Environmental [a]	subject to approval	1,031	1,108
Asset retirement obligations [a]	44	517	505
Loss on reacquired debt [a]	30	20,667	22,266
Renewable energy standard adjustment [a]	5	1,088	1,605
Deferred taxes on flow through accounting [c]	54	26,978	37,498
Decommissioning costs	10	13,287	16,859
Gas supply contract termination [a]	4	20,001	26,666
Other regulatory assets [a]	30	32,837	24,189
		$ 297,454	$ 296,142
Regulatory liabilities			
Deferred energy and gas costs [a]	1	$ 3,427	$ 10,368
Employee benefit plan costs and related deferred taxes [c]	12	40,629	68,654
Cost of removal [a]	44	130,932	118,410
Excess deferred income taxes [c] [d]	40	301,553	62
Revenue subject to refund	1	1,488	2,485
Other regulatory liabilities [c]	25	7,097	6,777
		$ 485,126	$ 206,756

(a) Recovery of costs, but we are not allowed a rate of return.
(b) In addition to recovery of costs, we are allowed a rate of return.
(c) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base.
(d) The increase in the regulatory tax liability is primarily related to the revaluation of deferred income tax balances at the lower income tax rate. As of December 31, 2017, all of the liability has been classified as non-current due to uncertainties around the timing and other regulatory decisions that will affect the amount of regulatory tax liability amortized and returned to customers through rate reductions or other revenue offsets in 2018.

Regulatory assets represent items we expect to recover from customers through probable future rates.

Deferred Energy and Fuel Cost Adjustments - Current - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our electric utility customers that is either higher or lower than the current rates and will be recovered or refunded in future rates. Deferred energy and fuel cost adjustments are recorded and recovered or amortized as approved by the appropriate state commission. Our electric and gas utilities file periodic quarterly, semi-annual and/or annual filings to recover these costs based on the respective cost mechanisms approved by their applicable state utility commissions.

Deferred Gas Cost Adjustment - Our regulated gas utilities have GCA provisions that allow them to pass the cost of gas on to their customers. The GCA is based on forecasts of the upcoming gas costs and recovery or refund of prior under-recovered or over-recovered costs. To the extent that gas costs are under-recovered or over-recovered, they are recorded as a regulatory asset or liability, respectively. Our Gas Utilities file periodic estimates of future gas costs based on market forecasts with state utility commissions.

Gas Price Derivatives - Our regulated utilities, as allowed or required by state utility commissions, have entered into certain exchange-traded natural gas futures and options to reduce our customers' underlying exposure to fluctuations in gas prices. Gas price derivatives represent our unrealized positions on our commodity contracts supporting our utilities. The 3-year term represents the maximum forward term hedged.

Deferred Taxes on AFUDC - The equity component of AFUDC is considered a permanent difference for tax purposes with the tax benefit being flowed through to customers as prescribed or allowed by regulators. If, based on a regulator's action, it is probable the utility will recover the future increase in taxes payable represented by this flow-through treatment through a rate revenue increase, a regulatory asset is recognized. This regulatory asset is a temporary difference for which a deferred tax liability must be recognized. Accounting standards for income taxes specifically address AFUDC-equity and require a gross-up of such amounts to reflect the revenue requirement associated with a rate-regulated environment.

Employee Benefit Plans - Employee benefit plans include the unrecognized prior service costs and net actuarial loss associated with our defined benefit pension plan and post-retirement benefit plans in regulatory assets rather than in AOCI, including costs being amortized from the Aquila and SourceGas Transactions.

Environmental - Environmental expenditures are costs associated with manufactured gas plant sites. The amortization of this asset is first offset by recognition of insurance proceeds and settlements with other third parties. Any remaining recovery will be requested in future rate filings. Recovery has not yet been approved by the applicable commission or board and therefore, the recovery period is unknown.

Asset Retirement Obligations - Asset retirement obligations represent the estimated recoverable costs for legal obligations associated with the retirement of a tangible long-lived asset. See Note 8 for additional details.

Loss on Reacquired Debt - Loss on reacquired debt is recovered over the remaining life of the original issue or, if refinanced, over the life of the new issue.

Renewable Energy Standard Adjustment - The renewable energy standard adjustment is associated with incentives for our Colorado Electric customers to install renewable energy equipment at their location. These incentives are recovered over time with an additional rider charged on customers' bills.

Deferred Taxes on Flow-Through Accounting - Under flow-through accounting, the income tax effects of certain tax items are reflected in our cost of service for the customer in the year in which the tax benefits are realized and result in lower utility rates. A regulatory asset was established to reflect that future increases in income taxes payable will be recovered from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a tax benefit for costs considered currently deductible for tax purposes, but are capitalized for book purposes.

Decommissioning Costs - South Dakota Electric and Colorado Electric received approval in 2014 for recovery of the remaining net book values and decommissioning costs of their decommissioned coal plants.

Gas Supply Contract Termination - Black Hills Gas Holdings had agreements under the previous ownership that required the Company to purchase all of the natural gas produced over the productive life of specific leaseholds in

the Bowdoin Field in Montana. The majority of these purchases were committed to distribution customers in Nebraska, Colorado, and Wyoming, which are subject to cost recovery mechanisms. The prices to be paid under these agreements varied, ranging from $6 to $8 per MMBtu at the time of acquisition, and exceeded market prices. We recorded a liability for this contract in our purchase price allocation. We were granted approval to terminate these agreements from the NPSC, CPUC and WPSC, on the basis that these agreements are not beneficial to customers over the long term. We received written orders allowing us to create a regulatory asset for the net buyout costs associated with the contract termination, and recover the majority of costs from customers over a period of five years. We terminated the contract and settled the liability on April 29, 2016.

Regulatory liabilities represent items we expect to refund to customers through probable future decreases in rates.

Deferred Energy and Gas Costs - Deferred energy costs and gas costs related to over-recovery of purchased power, transmission and natural gas costs.

Employee Benefit Plan Costs and Related Deferred Taxes - Employee benefit plans represent the cumulative excess of pension and retiree healthcare costs recovered in rates over pension expense recorded in accordance with accounting standards for compensation - retirement benefits. In addition, this regulatory liability includes the income tax effect of the adjustment required under accounting for compensation - defined benefit plans, to record the full pension and post-retirement benefit obligations. Such income tax effect has been grossed-up to account for the revenue requirement associated with a rate regulated environment.

Cost of Removal - Cost of removal represents the estimated cumulative net provisions for future removal costs for which there is no legal obligation for removal included in depreciation expense.

Excess Deferred Income Taxes - The revaluation of the regulated utilities' deferred tax assets and liabilities due to the passage of the TCJA is recorded as an excess deferred income tax to be refunded to customers primarily using the normalization principles as prescribed in the TCJA.

Income Taxes

The Company and its subsidiaries file consolidated federal income tax returns. As a result of the SourceGas transaction, certain subsidiaries acquired file as a separate consolidated group. Where applicable, each tax-paying entity records income taxes as if it were a separate taxpayer and consolidating adjustments are allocated to the subsidiaries based on separate company computations of taxable income or loss.

We use the asset and liability method in accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA makes broad and complex changes to the U.S. tax code, including, but not limited to reducing the U.S. federal corporate tax rate from 35% to 21%. The Company uses the asset and liability method in accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. As such, the Company has remeasured the deferred income taxes at the 21% federal tax rate as of December 31, 2017.

It is our policy to apply the flow-through method of accounting for investment tax credits as allowed by our rate-regulated jurisdictions. Under the flow-through method, investment tax credits are reflected in net income as a reduction to income tax expense in the year they qualify. An exception to this general policy is the deferral method, which applies to our regulated businesses. Such a method results in the investment tax credit being amortized as a reduction to income tax expense over the estimated useful lives of the underlying property that gave rise to the credit.

We recognize interest income or interest expense and penalties related to income tax matters in Income tax (expense) benefit on the Consolidated Statements of Income (Loss).

We account for uncertainty in income taxes recognized in the financial statements in accordance with the accounting standards for income taxes. The unrecognized tax benefit is classified in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets. See Note 15 for additional information.

Earnings per Share of Common Stock

Basic earnings per share from continuing and discontinued operations is computed by dividing Net income (loss) from continuing and discontinued operations by the weighted average number of common shares outstanding during each year. Diluted earnings per share is computed by including all dilutive common shares outstanding during each year. Diluted common shares are primarily due to equity units, and outstanding stock options, restricted stock and performance shares under our equity compensation plans.

A reconciliation of share amounts used to compute earnings (loss) per share is as follows for the years ended December 31 (in thousands):

	2017	2016	2015
Net income (loss) available for common stock	$ 177,034	$ 72,970	$ (32,111)
Weighted average shares - basic	53,221	51,922	45,288
Dilutive effect of:			
Equity Units	1,783	1,222	—
Equity compensation	116	127	—
Weighted average shares - diluted	55,120	53,271	45,288
Net income (loss) available for common stock, per share - Diluted	$ 3.21	$ 1.37	$ (0.71)

Due to our Net loss available for common stock for the year ended December 31, 2015, potentially diluted securities were excluded from the diluted loss per share calculation due to their anti-dilutive effect. In computing diluted net loss per share, 83,000 equity compensation shares were excluded from the computation for the year ended December 31, 2015.

The following outstanding securities were not included in the computation of diluted earnings per share as their effect would have been anti-dilutive for the years ended December 31 (in thousands):

	2017	2016	2015
Equity compensation	11	3	112
Equity units	—	—	6,440
Anti-dilutive shares excluded from computation of earnings (loss) per share	11	3	6,552

Business Combinations

We record acquisitions in accordance with ASC 805, *Business Combinations,* with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. The excess of the purchase price over the estimated fair values of the net tangible and net intangible assets acquired is recorded as goodwill. The application of ASC 805, *Business Combinations* requires management to make significant estimates and assumptions in the determination of the fair value of assets acquired and liabilities assumed in order to properly allocate purchase price consideration between goodwill and assets that are depreciated and amortized. Our estimates are based on historical experience, information obtained from the management of the acquired companies and, when appropriate, include assistance from independent third-party appraisal firms. These estimates are inherently uncertain and unpredictable. In addition, unanticipated events or circumstances may occur which may affect the accuracy or validity of such estimates. See Note 2 for additional detail on the accounting for the SourceGas Acquisition.

Noncontrolling Interest

We account for changes in our controlling interests of subsidiaries according to ASC 810, *Consolidations.* ASC 810 requires that the Company record such changes as equity transactions, recording no gain or loss on such a sale. GAAP requires that noncontrolling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet. In addition, the amounts attributable to the noncontrolling interest net income (loss) of those subsidiaries are reported separately in the consolidated statements of income and comprehensive income. See Note 12 for additional detail on Noncontrolling Interests.

Share-Based Compensation

We account for our share-based compensation arrangements in accordance with ASC 718, *Compensation-Stock Compensation*, by recognizing compensation costs for all share-based awards over the respective service period for employee services received in exchange for an award of equity or equity-based compensation. Awards that will be settled in stock are accounted for as equity and the compensation expense is based on the grant date fair value. Awards that are settled in cash are accounted for as liabilities and the compensation expense is re-measured each period based on the current market price and performance achievement measures.

Recently Issued Accounting Standards

Revenue from Contracts with Customers, ASU 2014-09

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*. The standard provides companies with a single model for use in accounting for revenue arising from contracts with customers and supersedes current revenue recognition guidance, including industry-specific revenue guidance. The core principle of the model is to recognize revenue when control of the goods or services transfers to the customer. The new disclosure requirements will provide information about the nature, amount, timing and uncertainty of revenue and cash flows from revenue contracts with customers. The guidance is effective for annual and interim reporting periods beginning after December 15, 2017. Entities have the option of using either a full retrospective or modified retrospective approach to adopting this guidance. Under the modified approach, an entity would recognize the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption.

We have implemented this standard effective January 1, 2018 on a modified retrospective basis. We have completed our assessment of all revenue from existing contracts with customers and there is no significant impact to our revenue recognition practices, financial position, results of operations or cash flows. A majority of our revenues are from regulated tariff offerings that provide natural gas or electricity with a defined contractual term, generally limited to the services requested and received to date for such arrangements. For such arrangements, the performance obligation transfer of control and revenue recognition occurs when the electricity or natural gas is delivered, consistent with the previous revenue recognition guidance. The same transfer of control and revenue recognition based on delivery principles also apply to our revenue contracts for wholesale and off-system power sales arrangements, coal supply agreements, and other non-regulated services. Therefore, we did not have a cumulative adjustment to Retained earnings or an impact on our revenue recognition policies as a result of the adoption of the new standard. The new standard will require us to provide more robust disclosures than required by previous guidance, including disclosures related to disaggregation of revenue into appropriate categories, performance obligations, and the judgments made in revenue recognition determinations.

Compensation - Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost, ASU 2017-07

In March 2017, the FASB issued ASU 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost*. The changes to the standard require employers to report the service cost component in the same line item(s) as other compensation costs, and require the other components of net periodic pension and post-retirement benefit costs to be separately presented in the income statement outside of income from operations. Additionally, only the service cost component may be eligible for capitalization, when applicable. However, all cost components remain eligible for capitalization under FERC regulations. This ASU will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension and post-retirement benefit costs in the income statement. The capitalization of only the service cost component of net periodic pension and post-retirement benefit costs in assets will be applied on a prospective basis. This new guidance is effective for annual periods beginning after December 15, 2017, including interim periods within those annual periods. We have implemented this standard effective January 1, 2018. For our rate-regulated entities, we will capitalize the other components of net periodic benefit costs into

regulatory assets or regulatory liabilities and maintain a FERC to GAAP reporting difference for these capitalized costs. The presentation changes required for net periodic pension and post-retirement costs will result in offsetting changes to Operating income and Other income, which are not expected to be material.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments, ASU 2016-15

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force)*. This ASU requires changes in the presentation of certain items, including but not limited to, debt prepayment or debt extinguishment costs; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies and distributions received from equity method investees. The ASU will be effective for fiscal years beginning after December 15, 2017. We have implemented this standard effective January 1, 2018 using the retrospective transition method. This standard will not have a material impact on our financial position, results of operations or cash flows.

Leases, ASU 2016-02

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842), which supersedes ASC 840, *Leases*. This ASU requires lessees to recognize a right-of-use asset and lease liability on the balance sheet for most leases, whereas today only financing-type lease liabilities (capital leases) are recognized on the balance sheet. In addition, the definition of a lease has been revised in regards to when an arrangement conveys the right to control the use of the identified asset under the arrangement which may result in changes to the classification of an arrangement as a lease. The ASU does not significantly change the lessees' recognition, measurement and presentation of expenses and cash flows from the previous accounting standard. Lessors' accounting under the ASU is largely unchanged from the previous accounting standard. The ASU expands the disclosure requirements of lease arrangements. Under the current guidance, lessees and lessors will use a modified retrospective transition approach, which requires application of the new guidance at the beginning of the earliest comparative period presented in the year of adoption. The guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted. In January 2018, the FASB issued amendments to the new lease standard, ASU No. 2018-01, allowing an entity to elect not to assess whether certain land easements are, or contain, leases when transitioning to the new lease standard.

We currently expect to adopt this standard on January 1, 2019 and anticipate electing the transition approach to not assess existing or expired land easements that were not previously accounted for as a lease. We continue to evaluate the impact of this new standard on our financial position, results of operations and cash flows as well as monitor emerging guidance on such topics as easements and rights of way, pipeline laterals, purchase power agreements, secondary use assets, and other industry-related areas. We continue the process of identifying and categorizing our lease contracts and evaluating our current business processes and systems.

Derivatives and Hedging: Targeted Improvement to Accounting for Hedging Activities, 2017-12

In August 2017, the FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvement to Accounting for Hedging Activities*. This standard better aligns risk management activities and financial reporting for hedging relationships, simplifies hedge accounting requirements and improves disclosures of hedging arrangements. This ASU is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. We are currently reviewing this standard to assess the impact on our financial position, results of operations and cash flows.

Simplifying the Test for Goodwill Impairment, 2017-04

In January 2017, the FASB issued ASU 2017-04, *Simplifying the Test for Goodwill Impairment* by eliminating step 2 from the goodwill impairment test. Under the new guidance, if the carrying amount of a reporting unit exceeds its fair value, an impairment loss will be recognized in an amount equal to that excess, limited to the amount of goodwill allocated to that reporting unit. The new standard is effective for interim and annual reporting periods beginning after December 15, 2019, applied on a prospective basis with early adoption permitted. We do not anticipate the adoption of this guidance to have any impact on our financial position, results of operations or cash flows.

Recently Adopted Accounting Standards

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income, ASU 2018-02

In February 2018, the FASB issued ASU 2018-02, *Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income.* This ASU was issued to address industry concerns regarding the application of current accounting guidance to certain provisions of the new tax reform legislation. This ASU permits entities to make a one-time reclassification from AOCI to retained earnings for stranded tax effects resulting from the newly enacted corporate tax rate. The amount of the reclassification is calculated on the basis of the difference between the historical and newly enacted tax rates for deferred tax liabilities and assets related to items within AOCI. The ASU is effective for fiscal years beginning after December 15, 2018, including interim periods therein, and early adoption is permitted. We have implemented this ASU effective December 22, 2017, the enactment date of the TCJA, which resulted in a reclassification of $7.0 million of stranded tax effects from AOCI to retained earnings. Adoption of this ASU did not have a material impact on our consolidated financial position, results of operations or cash flows.

Improvements to Employee Share-Based Payment Accounting, ASU 2016-09

In March 2016, the FASB issued ASU 2016-09, *Improvements to Employee Share-Based Payment Accounting*. This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for forfeitures, income taxes, and statutory tax withholding requirements. The ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, with early adoption permitted. Certain amendments of this guidance are to be applied retrospectively and others prospectively. We implemented this ASU effective January 1, 2017, recording a cumulative-effect adjustment of $3.2 million to Retained earnings in the Consolidated Balance Sheets as of the date of adoption, representing previously recorded forfeitures and excess tax benefits generated in years prior to 2017 that were previously not recognized in stockholders' equity due to NOLs in those years. Adoption of this ASU did not have a material impact on our consolidated financial position, results of operations or cash flows.

(2) ACQUISITION

Acquisition of SourceGas

On February 12, 2016, Black Hills Corporation acquired SourceGas, pursuant to the purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, including the assumption of $760 million in debt at closing. The purchase price was subject to post-closing adjustments for capital expenditures, indebtedness and working capital. Post-closing adjustments of approximately $11 million were agreed to and received from the sellers in June 2016. SourceGas is a 100% owned subsidiary of Black Hills Utility Holdings, Inc., a wholly-owned subsidiary of Black Hills Corporation and has been renamed Black Hills Gas Holdings, LLC. Black Hills Gas Holdings primarily operates four regulated natural gas utilities serving approximately 429,000 customers in Arkansas, Colorado, Nebraska and Wyoming, and a 512-mile regulated intrastate natural gas transmission pipeline in Colorado.

Cash consideration of $1.135 billion paid on February 12, 2016 to close the SourceGas Acquisition included net proceeds of approximately $536 million from the November 23, 2015 issuance of 6.325 million shares of our common stock, 5.98 million equity units, and $546 million in net proceeds from our debt offerings on January 13, 2016. We funded the cash consideration and out-of-pocket expenses payable with the SourceGas Acquisition using the proceeds listed above, cash on hand, and draws under our revolving credit facility.

In connection with the acquisition, the Company recorded pre-tax, incremental acquisition costs of approximately $45 million and $10 million for the years ending December 31, 2016 and 2015, respectively. These costs consisted of transaction costs, professional fees, employee-related expenses and other miscellaneous costs. The costs are recorded primarily in Other operating expenses and Interest expense on the Consolidated Statements of Income (Loss).

Our consolidated operating results for the year ended December 31, 2016 include revenues of $348 million and net income (loss) of $15 million, attributable to SourceGas for the period from February 12 through December 31, 2016. The SourceGas operating results are reported in our Gas Utilities segment. We believe the SourceGas Acquisition enhances Black Hills Corporation’s utility growth strategy, providing greater operating scale, driving more efficient delivery of services and benefiting customers.

We accounted for the SourceGas Acquisition in accordance with ASC 805, *Business Combinations*, with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date. Substantially all of SourceGas’ operations are subject to the rate-setting authority of state regulatory commissions, and are accounted for in accordance with GAAP for regulated operations. SourceGas’ assets and liabilities subject to rate setting provisions provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. As such, the fair value of these assets and liabilities equal their historical net book values.

The final purchase price allocation of the fair value of the assets acquired and liabilities assumed is included in the table below. The cash consideration paid of $1.124 billion, net of long-term debt assumed of $760 million and a working capital adjustment received of approximately $11 million, resulted in goodwill of $940 million. We had up to one year from the acquisition date to finalize the purchase price allocation. The working capital adjustment received in 2016 of $11 million reflected changes in valuation estimates for intangible assets, accrued liabilities and deferred taxes. Approximately $252 million of the goodwill balance is amortizable for tax purposes, relating to the partnership interests that were directly acquired in the transaction. The remainder of the goodwill balance is not amortizable for tax purposes. Goodwill generated from the acquisition reflects the benefits of increased operating scale and organic growth opportunities.

		(in thousands)
Purchase Price	$	1,894,882
Less: Long-term debt assumed		(760,000)
Less: Working capital adjustment received		(10,644)
Consideration paid, net of working capital adjustment received	$	1,124,238
Allocation of Purchase Price:		
Current Assets	$	112,983
Property, plant & equipment, net		1,058,093
Goodwill		939,695
Deferred charges and other assets, excluding goodwill		133,299
Current liabilities		(172,454)
Long-term debt		(758,874)
Deferred credits and other liabilities		(188,504)
Total consideration paid, net of working-capital adjustment received	$	1,124,238

Conditions of SourceGas Acquisition Regulatory Approval

The acquisition was subject to regulatory approvals from the public utility commissions in Arkansas (APSC), Colorado (CPUC), Nebraska (NPSC), and Wyoming (WPSC). Approvals were obtained from all commissions, subject to various conditions as set forth below:

The APSC order includes a twelve-month base rate moratorium, an annual $0.25 million customer credit for a term of up to five years or until we file the next rate review, whichever comes first, and provides the Company recovery of a portion of specific labor synergies at the time of the next base rate review, as well as various other terms and reporting requirements.

The CPUC order includes a two-year base rate moratorium for our regulated transmission and wholesale natural gas provider, a three-year base rate moratorium for our regulated gas distribution utility, an annual $0.2 million customer credit for a term of up to five-years or until we file the next rate review, whichever comes first, and provides the Company recovery of a portion of specific labor synergies at the time of the next base rate case, as well as various other terms and reporting requirements.

The NPSC order includes a three-year base rate moratorium, a three-year continuation of the Choice Gas Program, and provides the Company recovery of a portion of specific labor synergies at the time of the next base rate review, as well as various other terms and reporting requirements.

The WPSC order includes a three-year continuation of the Choice Gas Program, as well as various other terms and reporting requirements.

All four orders also disallowed recovery of goodwill and transaction costs. Recovery of transition costs is disallowed in Arkansas, Colorado and Nebraska. However, Wyoming allows for request of recovery of transition costs. Transition costs are those non-recurring costs related to the transition and integration of SourceGas. In the conditions mentioned above, the orders that include base rate moratoriums over a specified period of time do not impact our ability to adjust rates through riders or gas supply cost recovery mechanisms as allowed under the current enacted state tariffs. In certain cases, we may file for leave to increase general base rates and/or cost of sales recovery limited to material adverse changes, but only if there are changes in law or regulations or the occurrence of other extraordinary events outside of our control which result in a material adverse change in revenues, revenue requirement and/or increase in operating costs.

Settlement of Gas Supply Contract

On April 29, 2016, we settled for $40 million, a former SourceGas contract that required the Company to purchase all of the natural gas produced over the productive life of specific leaseholds in the Bowdoin Field in Montana. This contract’s intangible negative fair value is included with Current liabilities in the purchase price allocation. Approximately 75% of these purchases were committed to distribution customers in Nebraska, Colorado and Wyoming, which are subject to cost recovery mechanisms, while the remaining 25% was not subject to regulatory recovery. The prices to be paid under this contract varied,

ranging from $6 to $8 per MMBtu at the time of acquisition and exceeded market prices. We applied for and were granted approval to terminate this agreement from the NPSC, CPUC and WPSC, on the basis that the agreement was not beneficial to customers in the long term. We received written orders allowing recovery of the net buyout costs associated with the contract termination that were allocated to regulated subsidiaries. These costs were recorded as a regulatory asset of approximately $30 million that is being recovered over a five-year period beginning April 29, 2016.

Pro Forma Results (unaudited)

We calculated the pro forma impact of the SourceGas Acquisition and the associated debt and equity financings on our operating results for the year ended December 31, 2016 and 2015. The following pro forma results give effect to the acquisition, assuming the transaction closed on January 1, 2015:

	Pro Forma Results December 31,	
	2016	2015
	(in thousands, except per share amounts)	
Revenue	$ 1,617,878	$ 1,720,618
Income from continuing operations	$ 177,040	$ 160,290
Net income (loss)	$ 112,878	$ (13,369)
Earnings from continuing operations per share, Basic	$ 3.41	$ 3.15
Earnings from continuing operations per share, Diluted	$ 3.32	$ 3.15

We derived the pro forma results for the SourceGas Acquisition based on historical financial information obtained from the sellers and certain management assumptions. Our pro forma adjustments relate to incremental interest expense associated with the financings to effect the transaction, and for the year ended December 31, 2015, also include adjustments to shares outstanding to reflect the equity issuances as if they had occurred on January 1, 2015, and to reflect pro forma dilutive effects of the equity units issued. The pro forma results do not reflect any cost savings, (or associated costs to achieve such savings) from operating efficiencies or restructuring that could result from the acquisition, and exclude any unique one-time items resulting from the acquisition that are not expected to have a continuing impact on the combined consolidated results. Pro forma results for the year ended December 31, 2016 reflect unfavorable weather impacts resulting in lower gas usage by our customers than in the same periods of the prior year. In addition, we calculated the tax impact of these adjustments at an estimated combined federal and state income tax rate of 37%.

These pro forma results are for illustrative purposes only and do not purport to be indicative of the results that would have been obtained had the SourceGas Acquisition been completed on January 1, 2015, or that may be obtained in the future.

Seller’s noncontrolling interest

As part of the SourceGas Transaction, a seller retained a 0.5% noncontrolling interest and we entered into an associated option agreement with the holder for the 0.5% retained interest. In March 2017, we exercised our call option and purchased the remaining 0.5% equity interest in SourceGas for $5.6 million.

(3) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment at December 31 consisted of the following (dollars in thousands):

	2017		2016		Lives (in years)	
Electric Utilities	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Property, Plant and Equipment	Weighted Average Useful Life (in years)	Minimum	Maximum
Electric plant:						
Production	$ 1,315,044	39	$ 1,303,101	41	30	55
Electric transmission	407,203	51	354,801	52	40	70
Electric distribution	755,213	48	712,575	48	15	75
Plant acquisition adjustment [(a)]	4,870	32	4,870	32	32	32
General	232,842	31	164,761	25	3	65
Capital lease - plant in service [(b)]	261,441	20	261,441	20	20	20
Total electric plant in service	2,976,613		2,801,549			
Construction work in progress	13,595		74,045			
Total electric plant	2,990,208		2,875,594			
Less accumulated depreciation and amortization	644,022		578,162			
Electric plant net of accumulated depreciation and amortization	$ 2,346,186		$ 2,297,432			

(a) The plant acquisition adjustment is included in rate base and is being recovered with 13 years remaining.
(b) Capital lease - plant in service represents the assets accounted for as a capital lease under the PPA between Colorado Electric and Black Hills Colorado IPP. The capital lease ends in conjunction with the expiration of the PPA on December 31, 2031.

Gas Utilities	2017 Property, Plant and Equipment	2017 Weighted Average Useful Life (in years)	2016 Property, Plant and Equipment	2016 Weighted Average Useful Life (in years)	Lives (in years) Minimum	Lives (in years) Maximum
Gas plant:						
Production	$ 10,495	35	$ 10,821	35	17	71
Gas transmission	366,433	48	338,729	48	22	70
Gas distribution	1,413,431	42	1,303,366	42	33	47
Cushion gas - depreciable [(a)]	3,539	28	3,539	28	28	28
Cushion gas - not depreciated [(a)]	47,466	0	47,055	0	0	0
Storage	28,520	31	27,686	31	15	48
General	336,869	19	339,382	19	3	44
Total gas plant in service	2,206,753		2,070,578			
Construction work in progress	44,440		28,446			
Total gas plant	2,251,193		2,099,024			
Less accumulated depreciation and amortization	229,170		194,585			
Gas plant net of accumulated depreciation and amortization	$ 2,022,023		$ 1,904,439			

(a) Cushion gas is the portion of natural gas necessary to force saleable gas from a storage field into the transmission system and for system balancing, representing a permanent investment necessary to use storage facilities and maintain reliability. Depreciation of cushion gas is determined by the respective regulatory jurisdiction in which the cushion gas resides.

	2017					Lives (in years)	
	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Power Generation	$ 155,569	$ 224	$ 155,793	$ 57,813	$ 97,980	33	2	40
Mining	158,370	—	158,370	108,844	49,526	14	2	59

	2016					Lives (in years)	
	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Power Generation	$ 161,430	$ 1,298	$ 162,728	$ 55,157	$ 107,571	33	2	40
Mining	151,709	4,642	156,351	105,219	51,132	13	2	59

	2017						Lives (in years)		
	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Add Accumulated Depreciation - Capital Lease Elimination [(a)]	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Corporate	$ 5,580	$ 6,374	$ 11,954	$ 309	$ 14,070	$ 25,715	8	3	30

(a) Reflects the elimination of the capital lease accumulated depreciation difference between Colorado Electric and Black Hills Colorado IPP of $14 million.

	2016						Lives (in years)		
	Property, Plant and Equipment	Construction Work in Progress	Total Property Plant and Equipment	Less Accumulated Depreciation, Depletion and Amortization	Add Accumulated Depreciation - Capital Lease Elimination [(a)]	Net Property, Plant and Equipment	Weighted Average Useful Life	Minimum	Maximum
Corporate	$ 9,625	$ 11,974	$ 21,599	$ 2,106	$ 6,110	$ 25,603	8	3	30

(a) Reflects the elimination of the capital lease accumulated depreciation difference between Colorado Electric and Black Hills Colorado IPP of $6.1 million.

(4) JOINTLY OWNED FACILITIES

Utility Plant

Our consolidated financial statements include our share of several jointly-owned utility facilities as described below. Our share of the facilities' expenses are reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income (Loss). Each owner of the facility is responsible for financing its investment in the jointly-owned facilities.

- South Dakota Electric owns a 20% interest in the Wyodak Plant, a coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp owns the remaining ownership percentage and operates the Wyodak Plant. South Dakota Electric receives its proportionate share of the Wyodak Plant's capacity and is committed to pay its proportionate share of its additions, replacements and operating and maintenance expenses. In addition to supplying South Dakota Electric with coal for its share of the Wyodak Plant, our Mining subsidiary, WRDC, supplies PacifiCorp's share of the coal to the Wyodak Plant under a separate long-term agreement. This coal supply agreement is collateralized by a mortgage on and a security interest in some of WRDC's coal reserves.

- South Dakota Electric also owns a 35% interest in, and is the operator of, the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. Basin Electric owns the remaining ownership percentage. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the WECC region and the MAPP region. The total transfer capacity of the tie is 400 MW, including 200 MW from West to East and 200 MW from East to West. South Dakota Electric is committed to pay its proportionate share of the additions and replacements and operating and maintenance expenses of the transmission tie.

- South Dakota Electric owns 52% of the Wygen III coal-fired generation facility. MDU and the City of Gillette each owns an undivided ownership interest in Wygen III and are obligated to make payments for costs associated with administrative services and their proportionate share of the costs of operating the plant for the life of the facility. We retain responsibility for plant operations. Our Mining subsidiary supplies coal to Wygen III for the life of the plant.

- Colorado Electric owns 50% of the Busch Ranch Wind Farm while AltaGas owns the remaining undivided ownership interest and is obligated to make payments for costs associated with their proportionate share of the costs of operating the wind farm for the life of the facility. We retain responsibility for operations of the wind farm.

Non-Regulated Plants

Our consolidated financial statements include our share of a jointly-owned non-regulated power generation facility as described below. Our share of direct expenses for the jointly-owned facility is included in the corresponding categories of operating expenses in the accompanying Consolidated Statements of Income (Loss). Each of the respective owners is responsible for providing its own financing.

- Black Hills Wyoming owns 76.5% of the Wygen I plant while MEAN owns the remaining ownership percentage. MEAN is obligated to make payments for its share of the costs associated with administrative services, plant operations and coal supply provided by our Mining subsidiary during the life of the facility. We retain responsibility for plant operations.

At December 31, 2017, our interests in jointly-owned generating facilities and transmission systems were (in thousands):

	Plant in Service	Construction Work in Progress	Accumulated Depreciation
Wyodak Plant	$ 114,405	$ 727	$ 58,955
Transmission Tie	$ 20,037	$ 242	$ 6,215
Wygen I	$ 109,552	$ 209	$ 40,465
Wygen III	$ 138,688	$ 406	$ 19,239
Busch Ranch Wind Farm	$ 18,899	$ —	$ 3,858

(5) BUSINESS SEGMENT INFORMATION

Our reportable segments are based on our method of internal reporting, which is generally segregated by differences in products, services and regulation. All of our operations and assets are located within the United States.

Segment information was as follows (in thousands):

Total Assets (net of intercompany eliminations) as of December 31,	2017	2016
Electric [(a)]	$ 2,906,275	$ 2,859,559
Gas	3,426,466	3,307,967
Power Generation [(a)]	60,852	73,445
Mining	65,455	67,347
Corporate and Other	115,612	112,760
Discontinued operations [(b)]	84,242	120,695
Total assets	$ 6,658,902	$ 6,541,773

(a) The PPA under which Black Hills Colorado IPP provides generation to support Colorado Electric customers from the Pueblo Airport Generation station is accounted for as a capital lease. As such, assets owned by our Power Generation segment are recorded at Colorado Electric under accounting for a capital lease.

(b) On November 1, 2017, the BHC Board of Directors approved a complete divestiture of our Oil and Gas segment. See Note 21 for additional information.

Capital Expenditures and Asset Acquisitions [a] for the years ended December 31,	2017	2016
Capital expenditures		
Electric Utilities	$ 138,060	$ 258,739
Gas Utilities	184,389	173,930
Power Generation	1,864	4,719
Mining	6,708	5,709
Corporate and Other	6,668	17,353
Total capital expenditures	337,689	460,450
Asset acquisitions		
Gas Utilities [b]	—	1,124,238
Total capital expenditures and asset acquisitions of continuing operations	337,689	1,584,688
Total capital expenditures of discontinued operations	23,222	6,669
Total capital expenditures and asset acquisitions	$ 360,911	$ 1,591,357

(a) Includes accruals for property, plant and equipment.
(b) SourceGas was acquired on February 12, 2016. Net cash paid of $1.124 billion was net of long-term debt assumed and working capital adjustments received. See Note 2.

Property, Plant and Equipment as of December 31,	2017	2016
Electric Utilities [a]	$ 2,990,208	$ 2,875,594
Gas Utilities	2,251,193	2,099,024
Power Generation [a]	155,793	162,728
Mining	158,370	156,351
Corporate and Other	11,954	21,599
Total property, plant and equipment	$ 5,567,518	$ 5,315,296

(a) The PPA under which Black Hills Colorado IPP provides generation to support Colorado Electric customers from the Pueblo Airport Generation station is accounted for as a capital lease. As such, assets owned by our Power Generation segment are recorded at Colorado Electric under accounting for a capital lease.

Year ended December 31, 2017	Consolidating Income Statement							
	Electric Utilities	Gas Utilities	Power Generation	Mining	Corporate	Intercompany Eliminations	Discontinued Operations	Total
Revenue	$ 689,945	$ 947,595	$ 7,263	$ 35,463	$ —	$ —	$ —	$ 1,680,266
Intercompany revenue	14,705	35	84,283	31,158	344,685	(474,866)	—	—
Total revenue	704,650	947,630	91,546	66,621	344,685	(474,866)	—	1,680,266
Fuel, purchased power and cost of natural gas sold	268,405	409,603	—	—	151	(114,871)	—	563,288
Operations and maintenance	172,307	269,190	32,382	44,882	296,067	(302,832)	—	511,996
Depreciation, depletion and amortization	93,315	83,732	5,993	8,239	21,031	(24,064)	—	188,246
Operating income (loss)	170,623	185,105	53,171	13,500	27,436	(33,099)	—	416,736
Interest expense	(55,229)	(80,829)	(3,959)	(228)	(152,416)	154,543	—	(138,118)
Interest income	2,955	2,254	1,123	23	115,382	(120,721)	—	1,016
Other income (expense), net	1,730	(829)	(54)	2,191	330,373	(331,303)	—	2,108
Income tax benefit (expense) [(a)]	(9,997)	(39,799)	10,333	(1,100)	(32,433)	(371)	—	(73,367)
Income (loss) from continuing operations	110,082	65,902	60,614	14,386	288,342	(330,951)	—	208,375
Income (loss) from discontinued operations, net of tax [(b)]	—	—	—	—	—	—	(17,099)	(17,099)
Net income (loss)	110,082	65,902	60,614	14,386	288,342	(330,951)	(17,099)	191,276
Net income attributable to noncontrolling interest	—	(107)	(14,135)	—	—	—	—	(14,242)
Net income (loss) available for common stock	$ 110,082	$ 65,795	$ 46,479	$ 14,386	$ 288,342	$ (330,951)	$ (17,099)	$ 177,034

(a) The effective tax rate is lower in 2017 resulting from revaluation of net deferred tax liabilities in accordance with ASC 740 and the enactment of the TCJA on December 22, 2017.

(b) Discontinued operations includes oil and gas property impairments (see Note 21).

Year ended December 31, 2016	Consolidating Income Statement							
	Electric Utilities	Gas Utilities	Power Generation	Mining	Corporate	Intercompany Eliminations	Discontinued Operations	Total
Revenue	$ 664,330	$ 838,343	$ 7,176	$ 29,067	$ —	$ —	$ —	$ 1,538,916
Intercompany revenue	12,951	—	83,955	31,213	347,500	(475,619)	—	—
Total revenue	677,281	838,343	91,131	60,280	347,500	(475,619)	—	1,538,916
Fuel, purchased power and cost of natural gas sold	261,349	352,165	—	—	456	(114,838)	—	499,132
Operations and maintenance	158,134	245,826	32,636	39,576	378,744	(326,846)	—	528,070
Depreciation, depletion and amortization	84,645	78,335	4,104	9,346	22,930	(23,827)	—	175,533
Operating income (loss)	173,153	162,017	54,391	11,358	(54,630)	(10,108)	—	336,181
Interest expense	(56,237)	(76,586)	(3,758)	(401)	(114,597)	115,469	—	(136,110)
Interest income	5,946	1,573	1,983	24	97,147	(105,244)	—	1,429
Other income (expense), net	3,193	184	2	2,209	179,838	(181,032)	—	4,394
Income tax benefit (expense)	(40,228)	(27,462)	(17,129)	(3,137)	28,398	457	—	(59,101)
Income (loss) from continuing operations	85,827	59,726	35,489	10,053	136,156	(180,458)	—	146,793
(Loss) from discontinued operations, net of tax [(a)]	—	—	—	—	—	—	(64,162)	(64,162)
Net income (loss)	85,827	59,726	35,489	10,053	136,156	(180,458)	(64,162)	82,631
Net income attributable to noncontrolling interest	—	(102)	(9,559)	—	—	—	—	(9,661)
Net income (loss) available for common stock	$ 85,827	$ 59,624	$ 25,930	$ 10,053	$ 136,156	$ (180,458)	$ (64,162)	$ 72,970

(a) Discontinued operations includes oil and gas property impairments (see Note 21).

Year ended December 31, 2015	Consolidating Income Statement							
	Electric Utilities	Gas Utilities	Power Generation	Mining	Corporate	Intercompany Eliminations	Discontinued Operations	Total
Revenue	$ 668,226	$ 551,300	$ 7,483	$ 34,313	$ —	$ —	$ —	$ 1,261,322
Intercompany revenue	11,617	—	83,307	30,753	227,708	(353,385)	—	—
Total revenue	679,843	551,300	90,790	65,066	227,708	(353,385)	—	1,261,322
Fuel, purchased power and cost of natural gas sold	269,409	299,645	—	—	122	(112,289)	—	456,887
Operations and maintenance	160,924	140,723	32,140	41,630	231,855	(229,790)	—	377,482
Depreciation, depletion and amortization	80,929	32,326	4,329	9,806	9,723	(10,580)	—	126,533
Operating income (loss)	168,581	78,606	54,321	13,630	(13,992)	(726)	—	300,420
Interest expense	(55,159)	(17,912)	(4,218)	(433)	(61,496)	54,568	—	(84,650)
Interest income	4,114	601	1,015	34	48,799	(52,942)	—	1,621
Other income (expense), net	1,216	315	71	2,247	70,929	(71,964)	—	2,814
Income tax benefit (expense)	(41,173)	(22,304)	(18,539)	(3,608)	6,606	361	—	(78,657)
Income (loss) from continuing operations	77,579	39,306	32,650	11,870	50,846	(70,703)	—	141,548
Income (loss) from discontinued operations, net of tax [(a)]	—	—	—	—	—	—	(173,659)	(173,659)
Net income (loss)	77,579	39,306	32,650	11,870	50,846	(70,703)	(173,659)	(32,111)
Net income attributable to noncontrolling interest	—	—	—	—	—	—	—	—
Net income (loss) available for common stock	$ 77,579	$ 39,306	$ 32,650	$ 11,870	$ 50,846	$ (70,703)	$ (173,659)	$ (32,111)

(a) Discontinued operations includes oil and gas property impairments (see Note 21).

Corporate expense reallocation

In accordance with GAAP, indirect corporate operating costs previously allocated to BHEP were not reclassified to discontinued operations. These corporate operating costs for 2017 were reallocated to our operating segments; allocated interest was reclassified to Corporate and Other. Indirect corporate operating costs for 2016 and 2015 were reclassified to Corporate and Other. The reallocation of these costs to our operating segments in 2017 and an estimate of how these costs could have been allocated to segments other than Corporate and Other in 2016 and 2015 is as follows (in thousands):

Business Segment	Year Ended		
	December 31, 2017	December 31, 2016	December 31, 2015
Electric Utilities	$ 1,323	$ 2,079	$ 3,344
Gas Utilities	1,571	2,292	1,815
Power Generation	177	320	543
Mining	101	196	321
Total reportable segments	3,172	4,887	6,023
Corporate and Other [(a)]	6,405	6,037	3,957
Total	$ 9,577	$ 10,924	$ 9,980

(a) Includes interest allocations in 2017, 2016 and 2015 of approximately $4.9 million, $5.6 million and $3.4 million, respectively.

(6) LONG-TERM DEBT

Long-term debt outstanding was as follows (dollars in thousands):

	Due Date	Interest Rate at December 31, 2017	Balance Outstanding December 31, 2017	Balance Outstanding December 31, 2016
Corporate				
Senior unsecured notes due 2023	November 30, 2023	4.25%	$ 525,000	$ 525,000
Senior unsecured notes due 2020	July 15, 2020	5.88%	200,000	200,000
Remarketable junior subordinated notes [b]	November 1, 2028	3.50%	299,000	299,000
Senior unsecured notes due 2019	January 11, 2019	2.50%	250,000	250,000
Senior unsecured notes due 2026	January 15, 2026	3.95%	300,000	300,000
Senior unsecured notes due 2027	January 15, 2027	3.15%	400,000	400,000
Senior unsecured notes, due 2046	September 15, 2046	4.20%	300,000	300,000
Corporate term loan due 2019 [a]	August 9, 2019	2.55%	300,000	400,000
Corporate term loan due 2021	June 7, 2021	2.32%	18,664	24,406
Total Corporate debt			2,592,664	2,698,406
Less unamortized debt discount			(3,808)	(4,413)
Total Corporate debt, net			2,588,856	2,693,993
Electric Utilities				
First Mortgage Bonds due 2044	October 20, 2044	4.43%	85,000	85,000
First Mortgage Bonds due 2044	October 20, 2044	4.53%	75,000	75,000
First Mortgage Bonds due 2032	August 15, 2032	7.23%	75,000	75,000
First Mortgage Bonds due 2039	November 1, 2039	6.13%	180,000	180,000
First Mortgage Bonds due 2037	November 20, 2037	6.67%	110,000	110,000
Industrial development revenue bonds due 2021 [c]	September 1, 2021	1.78%	7,000	7,000
Industrial development revenue bonds due 2027 [c]	March 1, 2027	1.78%	10,000	10,000
Series 94A Debt, variable rate [c]	June 1, 2024	1.83%	2,855	2,855
Total Electric Utilities debt			544,855	544,855
Less unamortized debt discount			(90)	(94)
Total Electric Utilities debt, net			544,765	544,761
Total long-term debt			3,133,621	3,238,754
Less current maturities			5,743	5,743
Less deferred financing costs [d]			18,478	21,822
Long-term debt, net of current maturities and deferred financing costs			$ 3,109,400	$ 3,211,189

(a) Variable interest rate, based on LIBOR plus a spread.
(b) See Note 12 for RSN details.
(c) Variable interest rate.
(d) Includes deferred financing costs associated with our Revolving Credit Facility of $1.7 million and $2.3 million as of December 31, 2017 and December 31, 2016, respectively.

Scheduled maturities of long-term debt, excluding amortization of premiums or discounts, for future years are (in thousands):

2018	$	5,743
2019	$	555,742
2020	$	205,743
2021	$	8,436
2022	$	—
Thereafter	$	2,361,855

Our debt securities contain certain restrictive financial covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2017.

Substantially all of the tangible utility property of South Dakota Electric and Wyoming Electric is subject to the lien of indentures securing their first mortgage bonds. First mortgage bonds of South Dakota Electric and Wyoming Electric may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures. The first mortgage bonds issued by South Dakota Electric and Wyoming Electric are callable, but are subject to make-whole provisions which would eliminate any economic benefit for us to call the bonds.

Assumption of Long-Term Debt

At the closing of the SourceGas Acquisition on February 12, 2016, we assumed $760 million in long-term debt, consisting of the following:

- $325 million, 5.9% senior unsecured notes with an original issue date of April 16, 2007, due April 1, 2017.
- $95 million, 3.98% senior secured notes with an original issue date of September 29, 2014, due September 29, 2019.
- $340 million unsecured corporate term loan due June 30, 2017. Interest under this term loan was LIBOR plus a margin of 0.875%.

The $760 million in long-term debt assumed in the SourceGas Acquisition was repaid in August 2016.

Debt Transactions

On May 16, 2017, we paid down $50 million on our Corporate term loan due August 9, 2019. On July 17, 2017, we paid down an additional $50 million on the same term loan. Short-term borrowings from our CP program were used to fund the payments on the Corporate term loan.

On August 19, 2016, we completed a public debt offering of $700 million principal amount of senior unsecured notes. The debt offering consisted of $400 million of 3.15% 10-year senior notes due January 15, 2027 and $300 million of 4.20% 30-year senior notes due September 15, 2046 (together the “Notes”). The proceeds of the Notes were used for the following:

- Repay the $325 million 5.9% senior unsecured notes assumed in the SourceGas Acquisition;
- Repay the $95 million, 3.98% senior secured notes assumed in the SourceGas Acquisition;
- Repay $100 million on the $340 million unsecured term loan assumed in the SourceGas Acquisition;
- Pay down $100 million of the $500 million three-year unsecured term loan discussed below;
- Payment of $29 million for the settlement of $400 million notional interest rate swap; and
- Remainder was used for general corporate purposes.

On August 9, 2016, we entered into a $500 million, three-year, unsecured term loan expiring on August 9, 2019. The proceeds of this term loan were used to pay down $240 million of the $340 million unsecured term loan assumed in the SourceGas

Acquisition and the $260 million term loan expiring on April 12, 2017. This new term loan has substantially similar terms and covenants as the amended and restated Revolving Credit Facility.

In accordance with regulatory orders related to the early termination and settlement of the gas supply contract described in Note 1, on June 7, 2016, we entered into a 2.32%, $29 million term loan, due June 7, 2021. Proceeds from this term loan were used to finance the early termination of the gas supply contract, resulting in a regulatory asset. Principal and interest are payable quarterly at approximately $1.6 million.

On January 13, 2016, we completed a public debt offering of $550 million principal amount of senior unsecured notes. The debt offering consisted of $300 million of 3.95%, ten-year senior notes due 2026, and $250 million of 2.50%, three-year senior notes due 2019. After discounts and underwriter fees, net proceeds from the offering totaled $546 million and were used as funding for the SourceGas Acquisition. The discounts are amortized over the life of each respective note.

Amortization Expense

Our deferred financing costs and associated amortization expense included in Interest expense on the accompanying Consolidated Statements of Income (Loss) were as follows (in thousands):

	Deferred Financing Costs Remaining at	Amortization Expense for the years ended December 31,		
	December 31, 2017	2017	2016	2015
Revolving Credit Facility	$ 1,703	$ 638	$ 537	$ 504
Senior unsecured notes due 2023	2,427	494	494	494
Senior unsecured notes due 2019	59	704	643	—
Senior unsecured notes due 2020	425	167	167	167
Senior unsecured notes due 2026	2,031	287	262	—
Senior unsecured notes due 2027	2,918	363	121	—
Senior unsecured notes due 2046	3,082	111	37	—
Corporate term loan due 2019	86	201	144	—
Bridge Term Loan	—	—	843	4,213
RSNs due 2028	1,326	122	122	10
First mortgage bonds due 2044 (South Dakota Electric)	639	24	24	24
First mortgage bonds due 2044 (Wyoming Electric)	591	22	23	22
First mortgage bonds due 2032	485	33	33	33
First mortgage bonds due 2039	1,657	76	76	76
First mortgage bonds due 2037	613	31	31	31
Other	436	76	304	43
Total	$ 18,478	$ 3,349	$ 3,861	$ 5,617

Dividend Restrictions

Our credit facility and other debt obligations contain restrictions on the payment of cash dividends when a default or event of default occurs. In addition, the agreements governing our equity units contain restrictions on the payment of cash dividends upon any time we have exercised our right to defer payment of contract adjustment payments under the purchase contracts or interest payments under the RSNs included in such equity units. As of December 31, 2017, we were in compliance with these covenants.

Due to our holding company structure, substantially all of our operating cash flows are provided by dividends paid or distributions made by our subsidiaries. The cash to pay dividends to our shareholders is derived from these cash flows. As a result, certain statutory limitations or regulatory or financing agreements could affect the levels of distributions allowed to be made by our subsidiaries. The following restrictions on distributions from our subsidiaries existed at December 31, 2017:

- Our utilities are generally limited to the amount of dividends allowed to be paid to our utility holding company under the Federal Power Act and settlement agreements with state regulatory jurisdictions. As of December 31, 2017, the restricted net assets at our Electric and Gas Utilities were approximately $257 million.

(7) NOTES PAYABLE

Our Revolving Credit Facility and debt securities contain certain restrictive financial covenants. As of December 31, 2017, we were in compliance with all of these financial covenants.

We had the following short-term debt outstanding at the Consolidated Balance Sheets date (in thousands):

	Balance Outstanding at	
	December 31, 2017	December 31, 2016
Revolving Credit Facility	$ —	$ 96,600
CP Program	211,300	—
Total	$ 211,300	$ 96,600

Revolving Credit Facility

On August 9, 2016, we amended and restated our corporate Revolving Credit Facility to increase total commitments to $750 million from $500 million and extend the term through August 9, 2021 with two one-year extension options (subject to consent from the lenders). This facility is similar to the former agreement, which includes an accordion feature that allows us, with the consent of the administrative agent and issuing agents and subject to receipt of additional commitments from existing or new lenders, to increase total commitments of the facility up to $1.0 billion. Borrowings continue to be available under a base rate or various Eurodollar rate options. The interest costs associated with the letters of credit or borrowings and the commitment fee under the Revolving Credit Facility are determined based upon our most favorable Corporate credit rating from either S&P or Moody’s for our unsecured debt. Based on our credit ratings, the margins for base rate borrowings, Eurodollar borrowings, and letters of credit were 0.250%, 1.250%, and 1.250%, respectively, at December 31, 2017. A 0.200% commitment fee is charged on the unused amount of the Revolving Credit Facility.

On December 22, 2016, we implemented a $750 million, unsecured CP Program that is backstopped by the Revolving Credit Facility. Amounts outstanding under the Revolving Credit Facility and the CP Program, either individually or in the aggregate, cannot exceed $750 million. The notes issued under the CP Program may have maturities not to exceed 397 days from the date of issuance and bear interest (or are sold at par less a discount representing an interest factor) based on, among other things, the size and maturity date of the note, the frequency of the issuance and our credit ratings. Under the CP Program, any borrowings rank equally with our unsecured debt. Notes under the CP Program are not registered and are offered and issued pursuant to a registration exemption. Our net amount borrowed under the CP Program during 2017 and our notes outstanding as of December 31, 2017 were $211 million. We did not borrow under the CP Program in 2016 and did not have any notes outstanding as of December 31, 2016. As of December 31, 2017, the weighted average interest rate on CP Program borrowings was 1.76%.

As of December 31, 2017 and 2016, we had outstanding letters of credit totaling approximately $27 million and approximately $36 million, respectively.

Deferred financing costs on the Revolving Credit Facility of $5.4 million are being amortized over its estimated useful life and included in Interest expense on the accompanying Consolidated Statements of Income (Loss).

Debt Covenants

On December 7, 2016, we amended our Revolving Credit Facility and term loan agreements, allowing the exclusion of the Remarketable Junior Subordinated Notes (RSNs) from our Consolidated Indebtedness to Capitalization Ratio covenant calculation. Under the amended and restated Revolving Credit Facility and term loan agreements, we are required to maintain a Consolidated Indebtedness to Capitalization Ratio not to exceed 0.65 to 1.00. Our Consolidated Indebtedness to

Capitalization Ratio is calculated by dividing (i) Consolidated Indebtedness, which includes letters of credit, certain guarantees issued and excludes RSNs by (ii) Capital, which includes Consolidated Indebtedness plus Net Worth, which excludes noncontrolling interests in subsidiaries and includes the aggregate outstanding amount of the RSNs.

Our Revolving Credit Facility and our Term Loans require compliance with the following financial covenant at the end of each quarter:

	At December 31, 2017	Covenant Requirement at December 31, 2017	
Consolidated Indebtedness to Capitalization Ratio	61%	Less than	65%

(8) ASSET RETIREMENT OBLIGATIONS

We have identified legal retirement obligations related to reclamation of coal mining sites in the Mining segment and removal of fuel tanks, asbestos, transformers containing polychlorinated biphenyls, an evaporation pond and wind turbines at the regulated Electric Utilities segment, retirement of gas pipelines at our Gas Utilities and asbestos at our Electric and Gas Utilities. We periodically review and update estimated costs related to these asset retirement obligations. The actual cost may vary from estimates because of regulatory requirements, changes in technology and increased costs of labor, materials and equipment.

The following tables present the details of AROs which are included on the accompanying Consolidated Balance Sheets in Other deferred credits and other liabilities (in thousands):

	December 31, 2016	Liabilities Incurred	Liabilities Settled	Accretion	Liabilities Acquired	Revisions to Prior Estimates [b]	December 31, 2017
Electric Utilities	$ 4,661	$ —	$ (4)	$ 268	$ —	$ 1,362	$ 6,287
Gas Utilities	29,775	—	—	1,142	—	2,321	33,238
Mining	12,440	—	(107)	651	—	(485)	12,499
Total	$ 46,876	$ —	$ (111)	$ 2,061	$ —	$ 3,198	$ 52,024

	December 31, 2015	Liabilities Incurred	Liabilities Settled	Accretion	Liabilities Acquired [a]	Revisions to Prior Estimates [b][c]	December 31, 2016
Electric Utilities	$ 4,462	$ —	$ —	$ 191	$ —	$ 8	$ 4,661
Gas Utilities	136	—	—	791	22,412	6,436	29,775
Mining	18,633	—	(105)	822	—	(6,910)	12,440
Total	$ 23,231	$ —	$ (105)	$ 1,804	$ 22,412	$ (466)	$ 46,876

(a) Represents our legal liability for retirement of gas pipelines, specifically to purge and cap these lines in accordance with Federal regulations. Approximately $22 million was recorded with the purchase price allocation of SourceGas.
(b) The Gas Utilities Revision to Prior Estimates represents our legal liability for retirement of gas pipelines, specifically to purge and cap these lines in accordance with Federal regulations.
(c) The 2016 Mining Revision to Prior Estimates reflects an approximately 33% reduction in equipment costs as promulgated by the State of Wyoming.

We also have legally required AROs related to certain assets within our electric transmission and distribution systems. These retirement obligations are pursuant to an easement or franchise agreement and are only required if we discontinue our utility service under such easement or franchise agreement. Accordingly, it is not possible to estimate a time period when these obligations could be settled and therefore, a liability for the cost of these obligations cannot be measured at this time.

We have identified legal retirement obligations related to plugging and abandonment of natural gas and oil wells. These obligations are classified as held for sale at December 31, 2017. See Note 21.

(9) RISK MANAGEMENT ACTIVITIES

Our activities in the regulated and non-regulated energy sectors expose us to a number of risks in the normal operations of our businesses. Depending on the activity, we are exposed to varying degrees of market risk and credit risk. To manage and mitigate these identified risks, we have adopted the Black Hills Corporation Risk Policies and Procedures. Valuation methodologies for our derivatives are detailed within Note 1.

Market Risk

Market risk is the potential loss that may occur as a result of an adverse change in market price or rate. We are exposed to the following market risks, including, but not limited to:

- Commodity price risk associated with our retail natural gas marketing activities and our fuel procurement for certain of our gas-fired generation assets; and
- Interest rate risk associated with our variable rate debt.

Credit Risk

Credit risk is the risk of financial loss resulting from non-performance of contractual obligations by a counterparty.

For production and generation activities, we attempt to mitigate our credit exposure by conducting business primarily with high credit quality entities, setting tenor and credit limits commensurate with counterparty financial strength, obtaining master netting agreements and mitigating credit exposure with less creditworthy counterparties through parental guarantees, prepayments, letters of credit and other security agreements.

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by review of their current credit information. We maintain a provision for estimated credit losses based upon historical experience and any specific customer collection issue that is identified.

Our credit exposure at December 31, 2017 was concentrated primarily among retail utility customers, investment grade companies, cooperative utilities and federal agencies. Our derivative and hedging activities included in the accompanying Consolidated Balance Sheets, Consolidated Statements of Income (Loss) and Consolidated Statements of Comprehensive Income (Loss) are detailed below and within Note 10.

Utilities

The operations of our utilities, including natural gas sold by our Gas Utilities and natural gas used by our Electric Utilities' generation plants or those plants under PPAs where our Electric Utilities must provide the generation fuel (tolling agreements) expose our utility customers to volatility in natural gas prices. Therefore, as allowed or required by state utility commissions, we have entered into commission-approved hedging programs utilizing natural gas futures, options, over-the-counter swaps and basis swaps to reduce our customers' underlying exposure to these fluctuations. These transactions are considered derivatives, and in accordance with accounting standards for derivatives and hedging, mark-to-market adjustments are recorded as Derivative assets or Derivative liabilities on the accompanying Consolidated Balance Sheets, net of balance sheet offsetting as permitted by GAAP.

For our regulated utilities' hedging plans, unrealized and realized gains and losses, as well as option premiums and commissions on these transactions are recorded as Regulatory assets or Regulatory liabilities in the accompanying Consolidated Balance Sheets in accordance with the state utility commission guidelines. When the related costs are recovered through our rates, the hedging activity is recognized in the Consolidated Statements of Income (Loss).

We buy, sell and deliver natural gas at competitive prices by managing commodity price risk. As a result of these activities, this area of our business is exposed to risks associated with changes in the market price of natural gas. We manage our exposure to such risks using over-the-counter and exchange traded options and swaps with counterparties in anticipation of forecasted purchases and/or sales during time frames ranging from January 2018 through May 2020. A portion of our over-the-counter swaps have been designated as cash flow hedges to mitigate the commodity price risk associated with deliveries under fixed price forward contracts to deliver gas to our Choice Gas Program customers. The effective portion of the gain or loss on these designated derivatives is reported in AOCI in the accompanying Consolidated Balance Sheets and the ineffective portion,

if any is reported in Fuel, purchased power and cost of natural gas sold. Effectiveness of our hedging position is evaluated at least quarterly.

The contract or notional amounts and terms of the natural gas derivative commodity instruments held by our Utilities are comprised of both short and long positions. We had the following net long positions as of:

	December 31, 2017		December 31, 2016	
	Notional (MMBtus)	Maximum Term (months) [a]	Notional (MMBtus)	Maximum Term (months) [a]
Natural gas futures purchased	8,330,000	36	14,770,000	48
Natural gas options purchased, net [b]	3,540,000	14	3,020,000	5
Natural gas basis swaps purchased	8,060,000	36	12,250,000	48
Natural gas over-the-counter swaps, net [c]	3,820,000	29	4,622,302	28
Natural gas physical commitments, net [d]	12,826,605	35	21,504,378	10

(a) Term reflects the maximum forward period hedged.
(b) Volumes purchased as of December 31, 2016 is net of 2,133,000 MMBtus of collar options (call purchase and put sale) transactions.
(c) As of December 31, 2017, 1,650,000 MMBtus of natural gas over-the-counter swaps purchased were designated as cash flow hedges.
(d) Volumes exclude contracts that qualify for normal purchase, normal sales exception.

Based on December 31, 2017 prices, a $0.7 million loss would be realized, reported in pre-tax earnings and reclassified from AOCI during the next 12 months. As market prices fluctuate, estimated and actual realized gains or losses will change during future periods.

Financing Activities

At December 31, 2017, we had no outstanding interest rate swap agreements. In October 2015 and January 2016, we entered into forward starting interest rate swaps with a notional value totaling $400 million to fix the Treasury yield component associated with the anticipated issuance of senior notes. These swaps were settled at a loss of $29 million in connection with the issuance of our $400 million of unsecured ten-year senior notes in August 2016. The effective portion of the loss in the amount of $28 million was recognized as a component of AOCI and will be recognized as interest expense over the ten-year life of the $400 million unsecured note issued on August 19, 2016. The ineffective portion of $1.0 million, related to the timing of the debt issuance, was recognized in earnings as a component of interest expense in 2016. The contract or notional amounts, terms of our interest rate swaps and the interest rate swaps balances reflected on the Consolidated Balance Sheets were as follows (dollars in thousands) as of:

	December 31, 2016	
	Interest Rate Swaps [a]	
Notional	$	50,000
Weighted average fixed interest rate		4.94%
Maximum terms in months		1
Derivative assets, non-current	$	—
Derivative liabilities, current	$	90
Derivative liabilities, non-current	$	—

(a) The $50 million in swaps expired in January 2017. These swaps were designated to borrowings on our Revolving Credit Facility and were priced using three-month LIBOR, matching the floating portion of the related borrowings.

Discontinued Operations

Our Oil and Gas segment was exposed to risks associated with changes in the market prices through the sale and delivery of oil and gas to its customers at competitive prices. Through December 2017, we used exchange traded futures, swaps and options to hedge portions of our crude oil and natural gas production to mitigate commodity price risk and preserve cash flows. Hedge accounting was elected on the swaps and futures contracts. These transactions were designated upon inception as cash flow hedges, documented under accounting standards for derivatives and hedging and initially met prospective effectiveness testing. As a result of divesting our Oil and Gas segment assets, these activities were discontinued and there were no outstanding derivative agreements as of December 31, 2017. Any cash flows associated with our crude oil and natural gas cash flow hedges

were no longer probable of occurring; therefore, we discontinued hedge accounting as of November 1, 2017. As a result, we reclassified the loss in accumulated other comprehensive income associated with the commodity contracts into earnings as a reduction of revenues and recognized a pre-tax loss of $0.3 million, which is included in net loss from discontinued operations on the Consolidated Statements of Income (Loss) for the year ended December 31, 2017.

At December 31, 2016, we had outstanding crude oil futures and swap contracts with notional volumes of 108,000 Bbls, crude oil options contracts with notional volumes of 36,000 Bbls and natural gas futures and swap contracts with notional volumes of 2,700,000 MMBtus.

Cash Flow Hedges

The impact of cash flow hedges on our Consolidated Statements of Income (Loss) is presented below for the years ended December 31, 2017, 2016 and 2015 (in thousands). Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

	December 31, 2017			
Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (2,941)	Interest expense	$ —
Commodity derivatives	Net (loss) from discontinued operations	913	Net (loss) from discontinued operations	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(243)	Fuel, purchased power and cost of natural gas sold	(75)
Total impact from cash flow hedges		$ (2,271)		$ (75)

	December 31, 2016			
Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (3,899)	Interest expense	$ (953)
Commodity derivatives	Net (loss) from discontinued operations	11,019	Net (loss) from discontinued operations	—
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(14)	Fuel, purchased power and cost of natural gas sold	—
Total		$ 7,106		$ (953)

Derivatives in Cash Flow Hedging Relationships	Location of Reclassifications from AOCI into Income	December 31, 2015 Amount of Gain/(Loss) Reclassified from AOCI into Income (Settlements)	Location of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Derivative (Ineffective Portion)
Interest rate swaps	Interest expense	$ (3,647)	Interest expense	$ —
Commodity derivatives	Net (loss) from discontinued operations	14,460	Net (loss) from discontinued operations	—
Total		$ 10,813		$ —

The following table summarizes the gains and losses arising from hedging transactions that were recognized as a component of other comprehensive income (loss) for the years ended December 31, 2017, 2016 and 2015. The amounts included in the table below exclude gains and losses arising from ineffectiveness because these amounts are immediately recognized in the Consolidated Statements of Net Income (Loss) as incurred.

	December 31, 2017	December 31, 2016	December 31, 2015
		(In thousands)	
Increase (decrease) in fair value:			
Interest rate swaps	$ —	$ (31,222)	$ 2,888
Forward commodity contracts	366	(573)	9,782
Recognition of (gains) losses in earnings due to settlements:			
Interest rate swaps	2,941	3,899	3,647
Forward commodity contracts	(670)	(11,005)	(14,460)
Total other comprehensive income (loss) from hedging	$ 2,637	$ (38,901)	$ 1,857

Derivatives Not Designated as Hedge Instruments

The following table summarizes the impacts of derivative instruments not designated as hedge instruments on our Consolidated Statements of Income (Loss) for the years ended December 31, 2017, 2016 and 2015 (in thousands). Note that this presentation does not reflect the expected gains or losses arising from the underlying physical transactions; therefore, it is not indicative of the economic gross profit we realized when the underlying physical and financial transactions were settled.

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) on Derivatives Recognized in Income	2017 Amount of Gain/(Loss) on Derivatives Recognized in Income	2016 Amount of Gain/(Loss) on Derivatives Recognized in Income	2015 Amount of Gain/(Loss) on Derivatives Recognized in Income
Commodity derivatives	Net (loss) from discontinued operations	$ —	$ (50)	$ —
Commodity derivatives	Fuel, purchased power and cost of natural gas sold	(2,207)	940	—
		$ (2,207)	$ 890	$ —

As discussed above, financial instruments used in our regulated utilities are not designated as cash flow hedges. However, there is no earnings

impact because the unrealized gains and losses arising from the use of these financial instruments are recorded as Regulatory assets or Regulatory liabilities. The net unrealized losses included in our Regulatory assets or Regulatory liability accounts related to the hedges in our Utilities were $12 million and $8.8 million at December 31, 2017 and 2016, respectively.

(10) FAIR VALUE MEASUREMENTS

Recurring Fair Value Measurements

There have been no significant transfers between Level 1 and Level 2 derivative balances during 2017 or 2016. Amounts included in cash collateral and counterparty netting in the following tables represent the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions, netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as cash collateral posted with the same counterparties.

A discussion of fair value of financial instruments is included in Note 11. Oil and gas derivative instruments are included in assets and liabilities held for sale discussed in Note 21. The following tables set forth, by level within the fair value hierarchy, our gross assets and gross liabilities and related offsetting as permitted by GAAP that were accounted for at fair value on a recurring basis for derivative instruments (in thousands):

	As of December 31, 2017				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives - Utilities	$ —	$ 1,586	$ —	$ (1,282)	$ 304
Total	$ —	$ 1,586	$ —	$ (1,282)	$ 304
Liabilities:					
Commodity derivatives - Utilities	$ —	$ 13,756	$ —	$ (11,497)	$ 2,259
Total	$ —	$ 13,756	$ —	$ (11,497)	$ 2,259

	As of December 31, 2016				
	Level 1	Level 2	Level 3	Cash Collateral and Counterparty Netting	Total
Assets:					
Commodity derivatives - Utilities	$ —	$ 7,469	$ —	$ (3,262)	$ 4,207
Total	—	7,469	—	(3,262)	4,207
Liabilities:					
Commodity derivatives - Utilities	$ —	$ 12,201	$ —	$ (11,144)	$ 1,057
Interest rate swaps	—	90	—	—	90
Total	$ —	$ 12,291	$ —	$ (11,144)	$ 1,147

Fair Value Measures by Balance Sheet Classification

As required by accounting standards for derivatives and hedges, fair values within the following tables are presented on a gross basis, aside from the netting of asset and liability positions permitted in accordance with accounting standards for offsetting and under terms of our master netting agreements and the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions.

The following tables present the fair value and balance sheet classification of our derivative instruments as of December 31, (in thousands):

		2017		2016	
	Balance Sheet Location	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives	Fair Value of Asset Derivatives	Fair Value of Liability Derivatives
Derivatives designated as hedges:					
Commodity derivatives	Derivative assets - current	$ —	$ —	$ 1,007	$ —
Commodity derivatives	Derivative assets - non-current	—	—	124	—
Commodity derivatives	Current assets held for sale	—	—	154	—
Commodity derivatives	Derivative liabilities - current	—	817	—	—
Commodity derivatives	Other deferred credits and other liabilities	—	67	—	7
Commodity derivatives	Current liabilities held for sale	—	—	—	1,090
Commodity derivatives	Noncurrent liabilities held for sale	—	—	—	231
Interest rate swaps	Derivative liabilities - current	—	—	—	90
Total derivatives designated as hedges		$ —	$ 884	$ 1,285	$ 1,418
Derivatives not designated as hedges:					
Commodity derivatives	Derivative assets - current	$ 304	$ —	$ 2,977	$ —
Commodity derivatives	Derivative assets - non-current	—	—	98	—
Commodity derivatives	Derivative liabilities - current	—	1,264	—	1,014
Commodity derivatives	Other deferred credits and other liabilities	—	111	—	36
Commodity derivatives	Current liabilities held for sale	—	—	—	265
Total derivatives not designated as hedges		$ 304	$ 1,375	$ 3,075	$ 1,315

Derivatives Offsetting

It is our policy to offset in our Consolidated Balance Sheets contracts which provide for legally enforceable netting of our accounts receivable and payable and derivative activities.

As required by accounting standards for derivatives and hedges, fair values within the following tables reconcile the gross amounts to the net amounts. Amounts included in Gross Amounts Offset on Consolidated Balance Sheets in the following tables include the netting of asset and liability positions permitted in accordance with accounting standards for offsetting as well as the impact of legally enforceable master netting agreements that allow us to settle positive and negative positions as well as cash collateral posted with the same counterparties. Additionally, the amounts reflect cash collateral on deposit in margin accounts at December 31, 2017 and December 31, 2016, to collateralize certain financial instruments, which are included in Derivative assets and/or Derivative liabilities. Therefore, the gross amounts are not indicative of either our actual credit exposure or net economic exposure.

Offsetting of derivative assets and derivative liabilities on our Consolidated Balance Sheets at December 31, 2017 was as follows (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Assets on Consolidated Balance Sheets
Subject to master netting agreement or similar arrangement:			
Commodity derivative:			
Utilities	$ 1,282	$ (1,282)	$ —
Total derivative assets subject to a master netting agreement or similar arrangement	1,282	(1,282)	—
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Utilities	304	—	304
Total derivative assets not subject to a master netting agreement or similar arrangement	304	—	304
Total derivative assets	$ 1,586	$ (1,282)	$ 304

Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Liabilities on Consolidated Balance Sheets
Subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Utilities	$ 11,497	$ (11,497)	$ —
Total derivative liabilities subject to a master netting agreement or similar arrangement	11,497	(11,497)	—
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Utilities	2,259	—	2,259
Total derivative liabilities not subject to a master netting agreement or similar arrangement	2,259	—	2,259
Total derivative liabilities	$ 13,756	$ (11,497)	$ 2,259

Offsetting of derivative assets and derivative liabilities on our Consolidated Balance Sheets as of December 31, 2016 were as follows (in thousands):

Derivative Assets	Gross Amounts of Derivative Assets	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Assets on Consolidated Balance Sheets
Subject to master netting agreement or similar arrangement:			
Commodity derivative:			
Utilities	$ 4,269	$ (3,262)	$ 1,007
Total derivative assets subject to a master netting agreement or similar arrangement	4,269	(3,262)	1,007
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Utilities	3,200	—	3,200
Total derivative assets not subject to a master netting agreement or similar arrangement	3,200	—	3,200
Total derivative assets	$ 7,469	$ (3,262)	$ 4,207

Derivative Liabilities	Gross Amounts of Derivative Liabilities	Gross Amounts Offset on Consolidated Balance Sheets	Net Amount of Total Derivative Liabilities on Consolidated Balance Sheets
Subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Utilities	$ 11,144	$ (11,144)	$ —
Total derivative liabilities subject to a master netting agreement or similar arrangement	11,144	(11,144)	—
Not subject to a master netting agreement or similar arrangement:			
Commodity derivative:			
Utilities	1,057	—	1,057
Interest Rate Swaps	90	—	90
Total derivative liabilities not subject to a master netting agreement or similar arrangement	1,147	—	1,147
Total derivative liabilities	$ 12,291	$ (11,144)	$ 1,147

(11) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments, excluding derivatives which are presented in Note 10, were as follows at December 31 (in thousands):

	2017		2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents [(a)]	$ 15,420	$ 15,420	$ 13,518	$ 13,518
Restricted cash and equivalents [(a)]	$ 2,820	$ 2,820	$ 2,274	$ 2,274
Notes payable [(b)]	$ 211,300	$ 211,300	$ 96,600	$ 96,600
Long-term debt, including current maturities [(c) (d)]	$ 3,115,143	$ 3,350,544	$ 3,216,932	$ 3,351,305

(a) Carrying value approximates fair value. Cash and restricted cash are classified in Level 1 in the fair value hierarchy.
(b) Notes payable consist of commercial paper borrowings in 2017 and borrowings on our Revolving Credit Facility in 2016. Carrying value approximates fair value due to the short-term length of maturity; since these borrowings are not traded on an exchange, they are classified in Level 2 in the fair value hierarchy.
(c) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy.
(d) Carrying amount of long-term debt is net of deferred financing costs.

Cash and Cash Equivalents

Included in cash and cash equivalents is cash, money market mutual funds, and term deposits. As part of our cash management process, excess operating cash is invested in money market mutual funds with our bank. Money market mutual funds are not deposits and are not insured by the U.S. Government, the FDIC, or any other government agency and involve investment risk including possible loss of principal. We believe however, that the market risk arising from holding these financial instruments is minimal.

Restricted Cash and Equivalents

Restricted cash and cash equivalents represent restricted cash and uninsured term deposits.

Notes Payable and Long-Term Debt

For additional information on our notes payable and long-term debt, see Note 6 and Note 7.

(12) EQUITY

Equity Units

On November 23, 2015, we issued 5.98 million equity units for total gross proceeds of $299 million. Each Equity Unit has a stated amount of $50 and consists of (i) a forward purchase contract to purchase the Company's common stock and (ii) a 1/20, or 5%, undivided beneficial ownership interest in $1,000 principal amount of RSNs due 2028. The RSNs, a debt instrument, and the forward purchase contracts, an equity instrument, are deemed to be separate instruments as the investor may trade the RSNs separately from the forward purchase contract and may also settle the forward purchase contract separately.

The forward purchase contracts obligate the holders to purchase from the Company on the settlement date, which shall be no later than November 1, 2018, for a price of $50 in cash, the following number of shares of our common stock, subject to anti-dilution adjustments:

- if the "Applicable Market Value" (AMV) of the Company's common stock, which is the average volume-weighted average price of the Company's common stock for the trading days during the 20 consecutive scheduled trading day period ending on the third scheduled trading day immediately preceding the forward purchase contract settlement date, equals or exceeds $47.2938, 1.0572 shares of the Company's common stock per Equity Unit;

- if the AMV is less than $47.2938 but greater than $40.25, a number of shares of the Company's common stock having a value, based on the AMV, equal to $50; and

- if the AMV is less than or equal to $40.25, 1.2422 shares of the Company's common stock.

The RSNs bear interest at a rate of 3.5% per year, payable quarterly, and mature on November 1, 2028. The RSNs will be remarketed in 2018. If this remarketing is successful, the interest rate on the RSNs will be reset, and thereafter interest will be payable semi-annually at the reset rate. If there is no successful remarketing, the interest rate on the RSNs will not be reset, and the holders of the RSNs will have the right to put the RSNs to the Company at a price equal to 100% of the principal amount, and the proceeds of the put right will be deemed to have been applied against the holders' obligation under the forward purchase contracts.

The Company also pays the Equity Unit holders quarterly contract adjustment payments at a rate of 4.25% per year of the stated amount of $50 per Equity Unit, or $2.125 per year up to November 1, 2018. The present value of the future contract adjustment payments, $33 million, was recorded as a reduction of shareholders' equity in the accompanying Consolidated Balance Sheets. Until settlement of the forward purchase contracts, the shares of stock underlying each forward purchase contract are not outstanding. The forward purchase contracts will only be included in the computation of diluted earnings per share to the extent they are dilutive. As of December 31, 2017, the forward purchase contracts were dilutive and therefore included in the computation of diluted earnings per share. Basic earnings per share will not be affected until the forward purchase contracts are settled and the holders thereof become stockholders.

Selected information about our equity units is presented below (in thousands except for percentages):

Issuance Date	Units Issued	Total Net Proceeds	Total Long-term Debt (RSNs)	RSN Interest Rate (annual)	Stock Purchase Contract Rate (annual)	Stock Purchase Contract Liability as of December 31, 2017
11/23/2015	5,980	$ 290,030	$ 299,000	3.50%	4.25%	$ 12,115

At-the-Market Equity Offering Program

On August 4, 2017, we renewed the ATM equity offering program, which reset the size of the program to an aggregate value of up to $300 million. The renewed program, which allows us to sell shares of our common stock, is the same as the prior year program other than the aggregate value increased from $200 million to $300 million. The shares may be offered from time to time pursuant to a sales agreement dated August 4, 2017. Shares of common stock are offered pursuant to our shelf registration statement filed with the SEC. We did not issue any common shares under the ATM equity offering program during the twelve months ended December 31, 2017. During the three months ended December 31, 2016, we issued 218,647 common shares for $13 million, net of $0.1 million in commissions under the ATM equity offering program. During the twelve months ended December 31, 2016, we issued an aggregate of 1,968,738 shares of common stock under the ATM equity offering program for $119 million, net of $1.2 million in commissions.

Common Stock Offering

On November 23, 2015, we issued 6.325 million shares of common stock pursuant to a public offering at $40.25 per share. Net proceeds were $246 million. The proceeds from the offering were used to partially fund the purchase of SourceGas, which closed on February 12, 2016.

Equity Compensation Plans

Our 2015 Omnibus Incentive Plan allows for the granting of stock, restricted stock, restricted stock units, stock options and performance shares. We had 979,464 shares available to grant at December 31, 2017.

Compensation expense is determined using the grant date fair value estimated in accordance with the provisions of accounting standards for stock compensation and is recognized over the vesting periods of the individual awards. As of December 31, 2017, total unrecognized compensation expense related to non-vested stock awards was approximately $12.0 million and is expected to be recognized over a weighted-average period of 1.9 years. Stock-based compensation expense included in Operations and maintenance on the accompanying Consolidated Statements of Income (Loss) was as follows for the years ended December 31 (in thousands):

	2017	2016	2015
Stock-based compensation expense	$ 7,626	$ 10,885	$ 4,076

Stock Options

The Company has not issued any stock options since 2014 and has 96,749 stock options outstanding at December 31, 2017. The amount of stock options granted during the last three years, and related exercise activity are not material to the Company's consolidated financial statements.

Restricted Stock

The fair value of restricted stock and restricted stock unit awards equals the market price of our stock on the date of grant.

The shares carry a restriction on the ability to sell the shares until the shares vest. The shares substantially vest over 3 years, contingent on continued employment. Compensation expense related to the awards is recognized over the vesting period.

A summary of the status of the restricted stock and restricted stock units at December 31, 2017, was as follows:

	Restricted Stock	Weighted-Average Grant Date Fair Value
	(in thousands)	
Balance at beginning of period	295	$ 52.15
Granted	111	60.63
Vested	(128)	51.44
Forfeited	(11)	53.80
Balance at end of period	267	$ 55.94

The weighted-average grant-date fair value of restricted stock granted and the total fair value of shares vested during the years ended December 31, was as follows:

	Weighted-Average Grant Date Fair Value	Total Fair Value of Shares Vested
		(in thousands)
2017	$ 60.63	$ 7,909
2016	$ 53.55	$ 4,602
2015	$ 50.01	$ 6,009

As of December 31, 2017, there was $9.9 million of unrecognized compensation expense related to non-vested restricted stock that is expected to be recognized over a weighted-average period of 2.0 years.

Performance Share Plan

Certain officers of the Company and its subsidiaries are participants in a performance share award plan, a market-based plan. Performance shares are awarded based on our total shareholder return over designated performance periods as measured against a selected peer group. In addition, certain stock price performance must be achieved for a payout to occur. The final value of the performance shares will vary according to the number of shares of common stock that are ultimately granted based upon the actual level of attainment of the performance criteria.

The performance awards are paid 50% in cash and 50% in common stock. The cash portion accrued is classified as a liability and the stock portion is classified as equity. In the event of a change-in-control, performance awards are paid 100% in cash. If it is determined that a change-in-control is probable, the equity portion of $2.5 million at December 31, 2017 would be reclassified as a liability.

Outstanding performance periods at December 31 were as follows (shares in thousands):

			Possible Payout Range of Target	
Grant Date	Performance Period	Target Grant of Shares	Minimum	Maximum
January 1, 2015	January 1, 2015 - December 31, 2017	43	0%	200%
January 1, 2016	January 1, 2016 - December 31, 2018	53	0%	200%
January 1, 2017	January 1, 2017 - December 31, 2019	51	0%	200%

A summary of the status of the Performance Share Plan at December 31 was as follows:

	Equity Portion		Liability Portion	
	Shares	Weighted-Average Grant Date Fair Value [(a)]	Shares	Weighted-Average Fair Value at December 31, 2017
	(in thousands)		(in thousands)	
Performance Shares balance at beginning of period	71	$ 52.29	71	
Granted	26	63.52	26	
Forfeited	(1)	55.01	(1)	
Vested	(22)	55.18	(22)	
Performance Shares balance at end of period	74	$ 55.31	74	$ 22.31

(a) The grant date fair values for the performance shares granted in 2017, 2016 and 2015 were determined by Monte Carlo simulation using a blended volatility of 23%, 24% and 21%, respectively, comprised of 50% historical volatility and 50% implied volatility and the average risk-free interest rate of the three-year United States Treasury security rate in effect as of the grant date.

The weighted-average grant-date fair value of performance share awards granted was as follows in the years ended:

	Weighted Average Grant Date Fair Value
December 31, 2017	$ 63.52
December 31, 2016	$ 47.76
December 31, 2015	$ 54.92

Performance plan payouts have been as follows (dollars and shares in thousands):

Performance Period	Year of Payment	Shares Issued	Cash Paid	Total Intrinsic Value
January 1, 2014 to December 31, 2016	2017	—	$ —	$ —
January 1, 2013 to December 31, 2015	2016	—	$ —	$ —
January 1, 2012 to December 31, 2014	2015	69	$ 3,657	$ 7,314

On January 30, 2018, the Compensation Committee of our Board of Directors determined that the Company's performance criteria for the January 1, 2015 through December 31, 2017 performance period was not met. As a result, there will be no payout for this period.

As of December 31, 2017, there was $2.1 million of unrecognized compensation expense related to outstanding performance share plans that is expected to be recognized over a weighted-average period of 1.6 years.

Shareholder Dividend Reinvestment and Stock Purchase Plan

We have a DRSPP under which shareholders may purchase additional shares of common stock through dividend reinvestment and/or optional cash payments at 100% of the recent average market price. We have the option of issuing new shares or purchasing the shares on the open market. We issued new shares during 2017 and 2016.

A summary of the DRSPP for the years ended December 31 is as follows (shares in thousands):

	2017	2016
Shares Issued	48	51
Weighted Average Price	$ 65.40	$ 58.24
Unissued Shares Available	308	356

Preferred Stock

Our articles of incorporation authorize the issuance of 25 million shares of preferred stock of which we had no shares of preferred stock outstanding.

Sale of Noncontrolling Interest in Subsidiary

Black Hills Colorado IPP owns and operates a 200 MW, combined-cycle natural gas generating facility located in Pueblo, Colorado. On April 14, 2016, Black Hills Electric Generation sold a 49.9%, noncontrolling interest in Black Hills Colorado IPP for $216 million to a third-party buyer. FERC approval of the sale was received on March 29, 2016. Black Hills Electric Generation is the operator of the facility, which is contracted to provide capacity and energy through 2031 to Black Hills Colorado Electric. Proceeds from the sale were used to pay down short-term debt and for other general corporate purposes.

ASC 810 requires the accounting for a partial sale of a subsidiary in which control is maintained and the subsidiary continues to be consolidated. The partial sale is required to be recorded as an equity transaction with no resulting gain or loss on the sale. GAAP requires that noncontrolling interests in subsidiaries and affiliates be reported in the equity section of a company's balance sheet. Distributions of net income attributable to noncontrolling interests are due within 30 days following the end of a quarter, but may be withheld as necessary by Black Hills Electric Generation.

Net income available for common stock for the years ended December 31, 2017 and December 31, 2016 was reduced by $14 million and $9.6 million, respectively, attributable to this noncontrolling interest. The net income allocable to the noncontrolling interest holders is based on ownership interests with the exception of certain agreed upon adjustments.

Black Hills Colorado IPP has been determined to be a variable interest entity (VIE) in which the Company has a variable interest. Black Hills Electric Generation has been determined to be the primary beneficiary of the VIE as Black Hills Electric Generation is the operator and manager of the generation facility and, as such, has the power to direct the activities that most significantly impact Black Hills Colorado IPP's economic performance. Black Hills Electric Generation, as the primary beneficiary, continues to consolidate Black Hills Colorado IPP. Black Hills Colorado IPP has not received financial or other support from the Company outside of pre-existing contractual arrangements during the reporting period. Black Hills Colorado IPP does not have any debt and its cash flows from operations are sufficient to support its ongoing operations.

We have recorded the following assets and liabilities on our consolidated balance sheets related to the VIE described above as of December 31:

	2017	2016
	(in thousands)	
Assets		
Current assets	$ 14,837	$ 12,627
Property, plant and equipment of variable interest entities, net	$ 208,595	$ 218,798
Liabilities		
Current liabilities	$ 4,565	$ 4,342

(13) REGULATORY MATTERS

Electric Utilities Rate Activity

South Dakota Electric Common Use System (CUS): The annual rate determination process is governed by the FERC formula rate protocols established in the filed FERC joint-access transmission tariff. Effective January 1, 2018 the annual revenue requirement increased by $3.3 million and included estimated weighted average capital additions of $45 million for 2017 and 2018. The annual transmission revenue requirement has a true up mechanism that is posted in June of each year.

South Dakota Electric Settlement: On June 16, 2017, South Dakota Electric received approval from the SDPUC on a settlement reached with the SDPUC staff agreeing to a 6-year moratorium period effective July 1, 2017. As part of this agreement, South Dakota Electric will not increase base rates, absent an extraordinary event. The moratorium period also includes suspension of both the Transmission Facility Adjustment and the Environmental Improvement Adjustment, and a $1.0 million increase to the annual power marketing margin guarantee during this period. Additionally, existing regulatory asset balances of approximately $13 million related to decommissioning and Winter Storm Atlas are being amortized over the moratorium period. These balances were previously being amortized over a 10-year period ending September 30, 2024. The vegetation management regulatory asset of $14 million, previously unamortized, is also being amortized over the moratorium period. The change in amortization periods for these costs increased annual amortization expense by approximately $2.7 million. The June 16, 2017 settlement had no impact to base rates.

Colorado Electric Rate Case filing: On December 19, 2016, Colorado Electric received approval from the CPUC to increase its annual revenues by $1.2 million to recover investments in a $63 million, 40 MW natural gas-fired combustion turbine and normal increases in operating expenses. This increase is in addition to approximately $5.9 million in annualized revenue being recovered under the Clean Air Clean Jobs Act construction financing rider. This turbine was completed in the fourth quarter of 2016, achieving commercial operation on December 29, 2016. The approval allowed a return on rate base of 6.02% for this turbine, with a 9.37% return on equity and a capital structure of 67.34% debt and 32.66% equity. Whereas, an authorized return on rate base of 7.4% was received for the remaining system investments, with a return on equity of 9.37% and an approved capital structure of 47.6% debt and 52.4% equity.

On January 9, 2017, we filed an application with the CPUC for rehearing, reargument or reconsideration of the Commission's December 19, 2016 decision which reduced our proposed $8.9 million annual revenue increase to $1.2 million. Concurrent with this application, we filed a motion for a Commissioner to recuse themselves from continuing to participate in any further proceedings in the rate review. On October 4, 2017, the Company filed an Opening Brief. The Company filed a Reply Brief on November 22, 2017. The matter is pending.

We believe the CPUC made errors in their December decision by demonstrating bias, making decisions not supported by evidence, making findings inconsistent with cost-recovery provisions of the Colorado Clean Air-Clean Jobs Act and the

Commission’s own prior decisions, and treating Colorado Electric differently than other regulated utilities in Colorado have been treated in similar situations.

Gas Utilities Rate Activity

On December 15, 2017, Arkansas Gas filed a rate review application with the APSC requesting an annual increase in revenue of approximately $30 million. The annual increase is based on a return on equity of 10.2% and a capital structure of 45.3% debt and 54.7% equity. This rate review was driven by approximately $160 million of investments made since 2016 to replace, upgrade and maintain Arkansas Gas’ approximately 5,500 miles of natural gas transmission and distribution pipelines. If approved, new rates would be implemented in the fourth quarter of 2018. We are reviewing the impact of tax reform as it applies to the filing.

On November 17, 2017, Wyoming Gas filed a rate review application with the WPSC requesting an annual increase in revenue of approximately $1.4 million for natural gas system improvements supporting its Northwest Wyoming customers. The annual increase is based on a return on equity of 10.2% and a capital structure of 46.0% debt and 54.0% equity. This rate review was driven by approximately $6 million of investments made since 2015 to replace, upgrade and maintain approximately 620 miles of natural gas transmission and distribution pipelines. If approved, new rates would be implemented in mid-2018. We are reviewing the impact of tax reform as it applies to the filing.

On November 1, 2017, RMNG filed a rate review with the CPUC requesting recovery of $3.1 million, which includes $0.2 million of new revenue related to system safety and integrity expenditures on projects for the period of 2014 through 2018. This SSIR request was approved by the CPUC in December 2017, and is effective January 1, 2018.

On October 3, 2017, RMNG filed a rate review application with the CPUC requesting an annual increase in revenue of $2.2 million and an extension of the SSIR to recover costs from 2018 through 2022. The annual increase is based on a return on equity of 12.25% and a capital structure of 53.37% debt and 46.63% equity. This rate review was driven by the impending expiration of the SSIR on May 31, 2018; this application requests a continuation of the SSIR through 2022. We are reviewing the impact of tax reform as it applies to the filing.

Monthly, Arkansas Gas files for recovery of projects related to the replacement of eligible mains (MRP) and projects for the relocation of certain at risk meters (ARMRP). On February 1, 2018, Arkansas Gas requested MRP revenue of $2.8 million and ARMPR revenue of $0.5 million for assets placed in service between April 1, 2016 and December 31, 2017. Pursuant to the Arkansas Gas Tariff, the filed rates are effective the date filed.

Annually, Arkansas Gas files for recovery of Stockton Storage revenue requirement through the Stockton Storage Acquisition Rates regulatory mechanism. On November 16, 2017 Arkansas Gas filed a request for recovery of $3.3 million for the revenue requirement year ended September 30, 2017. Rates were effective January 1, 2017.

On October 2, 2017, Nebraska Gas Distribution filed with the NPSC requesting recovery of $6.8 million, which includes $0.3 million of increased annual revenue related to system safety and integrity expenditures on projects for the period of 2012 through 2017. This SSIR tariff was approved by the NPSC in January 2018, and went into effect on February 1, 2018.

In February 2016, Arkansas Gas implemented new base rates resulting in a revenue increase of $8.0 million. The APSC modified a stipulation reached between the APSC Staff and all intervenors except the Attorney General and Arkansas Gas in its order issued on January 28, 2016. The modified stipulation revised the capital structure to 52% debt and 48% equity and also limited recovery of portions of cost related to incentive compensation.

(14) OPERATING LEASES

We have entered into lease agreements for vehicles, equipment and office facilities. Rental expense incurred under these operating leases, including month to month leases, for the years ended December 31 was as follows (in thousands):

	2017	2016	2015
Rent expense	$ 10,325	$ 9,568	$ 7,177

The following is a schedule of future minimum payments required under the operating lease agreements (in thousands):

2018	$ 5,030
2019	$ 3,840
2020	$ 1,957
2021	$ 918
2022	$ 808
Thereafter	$ 3,085

(15) INCOME TAXES

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA reduced the U.S. federal corporate tax rate from 35% to 21%. The Company uses the asset and liability method in accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the book and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. As such, the Company has remeasured the deferred income taxes at the 21% federal tax rate as of December 31, 2017. The entities subject to regulatory construct have made their best estimate regarding the probability of settlements of net regulatory liabilities established pursuant to the TCJA. The amount of the settlements may change based on decisions and actions by the rate regulators, which could have a material impact on the Company's future results of operations, cash flows or financial position. As a result of the revaluation, deferred tax assets and liabilities were reduced by approximately $309 million. Of the $309 million, approximately $301 million is related to our regulated utilities and is reclassified to a regulatory liability. This regulatory liability will generally be amortized over the remaining life of the related assets using the normalization principles as specifically prescribed in the TCJA.

In addition, as allowed under SEC Staff Accounting Bulletin No. 118 (SAB 118), the Company has recorded provisional income tax amounts as of December 31, 2017 for changes pursuant to the TCJA related to depreciation, for which the impacts could not be finalized upon issuance of the Company's financial statements but reasonable estimates could be determined. The provisional amounts may change as the Company finalizes the analysis and computations, and such changes could be material to the Company's future results of operations, cash flows or financial position.

Income tax expense (benefit) from continuing operations for the years ended December 31 was (in thousands):

	2017	2016	2015
Current:			
Federal	$ (6,193)	$ (21,806)	$ 2,624
State	(1,432)	(1,797)	1,329
	(7,625)	(23,603)	3,953
Deferred:			
Federal	76,567	78,997	71,332
State	4,470	3,759	3,485
Tax credit amortization	(45)	(52)	(113)
	80,992	82,704	74,704
	$ 73,367	$ 59,101	$ 78,657

Included in discontinued operations is a tax benefit of $8.4 million, $49 million and $101 million for 2017, 2016 and 2015, respectively.

The temporary differences, which gave rise to the net deferred tax liability, for the years ended December 31 were as follows (in thousands):

	2017	2016
Deferred tax assets:		
Regulatory liabilities	$ 90,742	$ 58,200
Employee benefits	18,724	28,873
Federal net operating loss	155,276	252,780
Other deferred tax assets[(a)]	74,561	83,675
Less: Valuation allowance	(9,121)	(9,263)
Total deferred tax assets	330,182	414,265
Deferred tax liabilities:		
Accelerated depreciation, amortization and other property-related differences[(b)]	(510,774)	(782,674)
Regulatory assets	(26,245)	(49,471)
Goodwill	(46,392)	(60,544)
State deferred tax liability	(58,930)	(50,258)
Deferred costs	(16,063)	(18,551)
Other deferred tax liabilities	(8,298)	(14,702)
Total deferred tax liabilities	(666,702)	(976,200)
Net deferred tax liability	$ (336,520)	$ (561,935)

(a) Other deferred tax assets consist primarily of alternative minimum tax credit and federal research and development credits. No single item exceeds 5% of the total net deferred tax liability.

(b) The net deferred tax liabilities were revalued for the change in federal tax rate to 21% under the TCJA. The revaluation resulted in a reduction to net deferred tax liabilities of approximately $309 million. Due to the regulatory construct, approximately $301 million of the revaluation was reclassified to a regulatory liability.

The effective tax rate differs from the federal statutory rate for the years ended December 31, as follows:

	2017	2016	2015
Federal statutory rate	35.0 %	35.0 %	35.0 %
State income tax (net of federal tax effect)	0.9	1.2	1.5
Percentage depletion	(0.6)	(0.8)	(0.7)
Non-controlling interest [(a)]	(1.8)	(1.6)	—
Equity AFUDC	(0.2)	(0.5)	(0.1)
Tax credits	(1.7)	(0.4)	(0.1)
Transaction costs	—	0.5	—
Accounting for uncertain tax positions adjustment	(0.2)	(2.7)	0.8
Flow-through adjustments [(b)]	(1.1)	(2.1)	(1.0)
Other tax differences	(0.9)	0.1	0.3
IRC 172(f) carryback claim	(0.7)	—	—
Tax Cuts & Jobs Act corporate rate reduction [(c)]	(2.7)	—	—
	26.0 %	28.7 %	35.7 %

(a) The effective tax rate reflects the income attributable to the noncontrolling interest in Black Hills Colorado IPP for which a tax provision was not recorded.
(b) Flow-through adjustments related primarily to accounting method changes for tax purposes that allow us to take a current tax deduction for repair costs and certain indirect costs. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and flowed the tax benefit through to tax expense. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record tax benefits consistent with the flow-through method.
(c) On December 22, 2017, the TCJA was signed into law reducing the federal corporate rate from 35% to 21% effective January 1, 2018. The 2017 effective tax rate reduction reflects the revaluation of deferred income taxes associated with non-regulated operations required by the change.

At December 31, 2017, we have federal and state NOL carryforwards that will expire at various dates as follows (in thousands):

		Amounts	Expiration Dates		
Federal Net Operating Loss Carryforward	$	739,184	2019	to	2037
State Net Operating Loss Carryforward	$	688,335	2017	to	2038

As of December 31, 2017, we had a $1.3 million valuation allowance against the state NOL carryforwards. Our 2017 analysis of the ability to utilize such NOLs resulted in a slight increase in the valuation allowance of approximately $0.4 million, which resulted in an increase to tax expense. The valuation allowance adjustment was primarily attributable to a projected decrease in state taxable income for years beyond 2017. This projected decrease impacted the utilization of NOL carryforward in those states where the carryforward period is significantly shorter than the federal carryforward period of 20 years. In certain states, the carryforward period is limited to 5 years. Ultimate usage of these NOLs depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the NOLs, the offsetting amount will affect tax expense.

The following table reconciles the total amounts of unrecognized tax benefits, without interest, at the beginning and end of the period included in Other deferred credits and other liabilities on the accompanying Consolidated Balance Sheets (in thousands):

	Changes in Uncertain Tax Positions
Beginning balance at January 1, 2015	$ 32,192
Additions for prior year tax positions	3,285
Reductions for prior year tax positions	(3,491)
Additions for current year tax positions	—
Settlements	—
Ending balance at December 31, 2015	31,986
Additions for prior year tax positions	2,423
Reductions for prior year tax positions	(19,174)
Additions for current year tax positions	—
Settlements	(11,643)
Ending balance at December 31, 2016	3,592
Additions for prior year tax positions	358
Reductions for prior year tax positions	(5,713)
Additions for current year tax positions	5,026
Settlements	—
Ending balance at December 31, 2017	$ 3,263

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately $0.2 million.

We recognized no interest expense for the years ended December 31, 2017 and December 31, 2016, and approximately $1.6 million for the year ended December 31, 2015. We had no accrued interest (before tax effect) associated with income taxes at December 31, 2017 and December 31, 2016.

Black Hills Corporation and its subsidiaries are currently under examination by the IRS for the 2010 to 2012 tax years. A 30-day Letter was received in second quarter 2016 along with a Revenue Agent’s Report from the IRS in regard to the audit of the 2010 to 2012 tax years disallowing certain R&D credits and deductions claimed with respect to certain costs and projects. In response to the 30-day Letter, a protest was timely filed with IRS Appeals in the second quarter of 2016 and a final settlement at IRS Appeals is expected to be reached in 2018. Black Hills Gas, Inc. and subsidiaries, which files a separate consolidated tax return from Black Hills Corporation and subsidiaries, is under examination by the IRS for 2014.

We had deferred a substantial amount of tax payments through various tax planning strategies including the deferral of approximately $125 million in income taxes attributable to the like-kind exchange effectuated in connection with the IPP Transaction and Aquila Transaction that occurred in 2008. The IRS had challenged our position with respect to the like-kind exchange. In the first quarter of 2016, we reached a settlement agreement in principle with IRS Appeals related to both the like-kind exchange transaction in addition to the R&D credits and deductions issues. In 2016, the settlement resulted in a reduction to the liability for unrecognized tax benefits of approximately $29 million excluding interest. Approximately $17 million of the reduction was to restore accumulated deferred income taxes and the remaining portion of approximately $12 million was reclassified to current taxes payable.

As of December 31, 2017, we do not have any tax positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease on or before December 31, 2018.

State tax credits have been generated and are available to offset future state income taxes. At December 31, 2017, we had the following state tax credit carryforwards (in thousands):

State Tax Credit Carryforwards			Expiration Year
Investment tax credit	$	20,285	2023 to 2036
Research and development	$	179	No expiration

As of December 31, 2017, we had a $7.8 million valuation allowance against the state tax credit carryforwards. The re-evaluation of our ability to utilize such credits resulted in an increase of the valuation allowance of approximately $1.2 million of which approximately $0.6 million resulted in an increase to tax expense. The remaining $0.6 million increase is attributable to our regulated business and is being accounted for under the deferral method whereby the credits are amortized to tax expense over the estimated useful life of the underlying asset that generated the credit. The valuation allowance adjustment was primarily attributable to the impact of lower projected apportionment factors resulting in decreased state taxable income in years beyond 2017. Ultimate usage of these credits depends upon our future tax filings. If the valuation allowance is adjusted due to higher or lower than anticipated utilization of the state tax credit carryforwards, the offsetting amount will affect tax expense.

(16) OTHER COMPREHENSIVE INCOME

We record deferred gains (losses) in AOCI related to interest rate swaps designated as cash flow hedges, commodity contracts designated as cash flow hedges and the amortization of components of our defined benefit plans. Deferred gains (losses) for our commodity contracts designated as cash flow hedges are recognized in earnings upon settlement, while deferred gains (losses) related to our interest rate swaps are recognized in earnings as they are amortized.

The following table details reclassifications out of AOCI and into net income. The amounts in parentheses below indicate decreases to net income in the Consolidated Statements of Income (Loss) for the period, net of tax (in thousands):

	Location on the Consolidated Statements of Income (Loss)	Amount Reclassified from AOCI	
		December 31, 2017	December 31, 2016
Gains and (losses) on cash flow hedges:			
Interest rate swaps	Interest expense	$ (2,941)	$ (3,899)
Commodity contracts	(Loss) from discontinued operations	913	11,019
Commodity contracts	Fuel, purchased power and cost of natural gas sold	(243)	(14)
		(2,271)	7,106
Income tax	Income tax benefit (expense)	875	(2,702)
Total reclassification adjustments related to cash flow hedges, net of tax		$ (1,396)	$ 4,404
Amortization of components of defined benefit plans:			
Prior service cost	Operations and maintenance	$ 168	$ 194
Prior service cost	(Loss) from discontinued operations	29	27
Actuarial gain (loss)	Operations and maintenance	(1,599)	(1,881)
Actuarial gain (loss)	(Loss) from discontinued operations	(58)	(97)
		(1,460)	(1,757)
Income tax	Income tax benefit (expense)	(516)	533
Total reclassification adjustments related to defined benefit plans, net of tax		$ (1,976)	$ (1,224)
Total reclassifications		$ (3,372)	$ 3,180

Balances by classification included within AOCI, net of tax on the accompanying Consolidated Balance Sheets were as follows (in thousands):

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2016	$ (18,109)	$ (233)	$ (16,541)	$ (34,883)
Other comprehensive income (loss) before reclassifications	—	231	(1,890)	(1,659)
Amounts reclassified from AOCI	1,912	(516)	944	2,340
Reclassification of certain tax effects from AOCI	(3,384)	—	(3,616)	(7,000)
As of December 31, 2017	$ (19,581)	$ (518)	$ (21,103)	$ (41,202)

	Derivatives Designated as Cash Flow Hedges			
	Interest Rate Swaps	Commodity Derivatives	Employee Benefit Plans	Total
As of December 31, 2015	$ (341)	$ 7,066	$ (15,780)	$ (9,055)
Other comprehensive income (loss) before reclassifications	(20,302)	(361)	(1,985)	(22,648)
Amounts reclassified from AOCI	2,534	(6,938)	1,224	(3,180)
As of December 31, 2016	$ (18,109)	$ (233)	$ (16,541)	$ (34,883)

(17) SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Years ended December 31,	2017	2016	2015
		(in thousands)	
Non-cash investing activities and financing from continuing operations -			
Property, plant and equipment acquired with accrued liabilities	$ 28,191	$ 27,034	$ 25,039
Increase (decrease) in capitalized assets associated with asset retirement obligations	$ 3,198	$ 8,577	$ (1,498)
Cash (paid) refunded during the period for continuing operations-			
Interest (net of amount capitalized)	$ (132,428)	$ (113,627)	$ (78,744)
Income taxes (paid) refunded	$ 1,775	$ (1,156)	$ (1,202)

(18) EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

We sponsor 401(k) retirement savings plans (the 401(k) Plans). Participants in the 401(k) Plans may elect to invest a portion of their eligible compensation in the 401(k) Plans up to the maximum amounts established by the IRS. The 401(k) Plans provide employees the opportunity to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis.

The 401(k) Plans provide either a Company Matching Contribution or a Non-Elective Safe Harbor Contribution for all eligible participants, depending upon the Plan in which the employee participates. Certain eligible participants receive a Company Retirement Contribution based on the participant's age and years of service or a Company Discretionary Contribution, depending upon the pension plan in which the employee participates. Vesting of all Company contributions ranges from immediate vesting to graduated vesting at 20% per year with 100% vesting when the participant has 5 years of service with the Company.

The SourceGas Retirement Savings Plan was merged into the Black Hills Corporation Retirement Savings Plan effective December 31, 2017. The plan design of the Black Hills Corporation 401(k) Plan will apply to all employees as of January 1, 2018.

Defined Benefit Pension Plan (Pension Plan)

At December 31, 2016 our three previous defined benefit pension plans consisting of the Black Hills Corporation Pension Plan, the Black Hills Utility Holding, Inc. Pension Plan and the SourceGas Retirement Plan were merged into one single plan, the Black Hills Retirement Plan (Pension Plan). The Pension Plan covers certain eligible employees of the Company. The benefits for the Pension Plan are based on years of service and calculations of average earnings during a specific time period prior to retirement. The Pension Plan is closed to new employees and frozen for certain employees who did not meet age and service based criteria.

The Pension Plan assets are held in a Master Trust. Due to the plan merger on December 31, 2016, reporting beginning in 2017 no longer represents an undivided interest in the Master Trust. Our Board of Directors has approved the Pension Plan's investment policy. The objective of the investment policy is to manage assets in such a way that will allow the eventual settlement of our obligations to the Pension Plan's beneficiaries. To meet this objective, our pension assets are managed by an outside adviser using a portfolio strategy that will provide liquidity to meet the Pension Plan's benefit payment obligations. The Pension Plan's assets consist primarily of equity, fixed income and hedged investments.

The expected rate of return on the Pension Plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2017, the expected rate of return on pension plan assets was based on the targeted asset allocation range of 37% to 45% equity securities and 55% to 63% fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets was based on the targeted asset allocation range of 15% to 25% equity securities and 75% to 85% fixed-income securities and the expected rate of return from these asset categories.

The expected long-term rate of return for investments was 6.25% and 6.75% for the Pension Plan 2017 and 2016 plan years, respectively. Our Pension Plan is funded in compliance with the federal government's funding requirements.

Plan Assets

The percentages of total plan asset by investment category for our Pension Plan at December 31 were as follows:

	2017	2016
Equity	26%	28%
Real estate	4	5
Fixed income	63	57
Cash	1	2
Hedge funds	6	8
Total	100%	100%

Supplemental Non-qualified Defined Benefit Plans

We have various supplemental retirement plans for key executives of the Company. The plans are non-qualified defined benefit and defined contribution plans (Supplemental Plans). The Supplemental Plans are subject to various vesting schedules and are not funded by the Company.

Plan Assets

We do not fund our Supplemental Plans. We fund on a cash basis as benefits are paid.

Non-pension Defined Benefit Postretirement Healthcare Plans

BHC sponsors retiree healthcare plans (Healthcare Plans) for employees who meet certain age and service requirements at retirement. Healthcare Plan benefits are subject to premiums, deductibles, co-payment provisions and other limitations. A portion of the Healthcare Plans for participating business units are pre-funded via VEBAs. Pre-65 retirees as well as a grandfathered group of post-65 Cheyenne Light, Fuel and Power (“CLFP”) retirees and a grandfathered group of post-65 former SourceGas employees who retired prior to January 1, 2017 receive their retiree medical benefits through the Black Hills self-insured retiree medical plans.

Healthcare coverage for Medicare-eligible BHC and Black Hills Utility Holdings retirees is provided through an individual market healthcare exchange. Medicare-eligible SourceGas employees who retired after December 31, 2016 also receive retiree medical coverage through an individual market healthcare exchange.

Plan Assets

We fund the Healthcare Plans on a cash basis as benefits are paid. The Black Hills Utility Holding and SourceGas Postretirement - AWG Plans provide for partial pre-funding via VEBAs and a Grantor Trust. Assets related to this pre-funding are held in trust and are for the benefit of the union and non-union employees located in the states of Arkansas, Kansas and Iowa. We do not pre-fund the Healthcare Plans for those employees outside Arkansas, Kansas and Iowa.

Plan Contributions

Contributions to the Pension Plan are cash contributions made directly to the Master Trust. Healthcare and Supplemental Plan contributions are made in the form of benefit payments. Healthcare benefits include company and participant paid premiums. Contributions for the years ended December 31 were as follows (in thousands):

	2017	2016
Defined Contribution Plan		
Company retirement contribution	$ 10,223	$ 9,632
Matching contributions	$ 9,811	$ 9,645

	2017	2016
Defined Benefit Plans		
Defined Benefit Pension Plan	$ 27,700	$ 14,200
Non-Pension Defined Benefit Postretirement Healthcare Plans	$ 4,332	$ 4,965
Supplemental Non-Qualified Defined Benefit Plans	$ 3,217	$ 1,565

While we do not have required contributions, we expect to make approximately $13 million in contributions to our Pension Plan in 2018.

Fair Value Measurements

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect their placement within the fair value hierarchy levels.

The following tables set forth, by level within the fair value hierarchy, the assets that were accounted for at fair value on a recurring basis (in thousands):

Pension Plan	December 31, 2017					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV [a]	Total Investments
AXA Equitable General Fixed Income	$ —	$ 1,280	$ —	$ 1,280	$ —	$ 1,280
Common Collective Trust - Cash and Cash Equivalents	—	2,184	—	2,184	—	2,184
Common Collective Trust - Equity	—	109,496	—	109,496	—	109,496
Common Collective Trust - Fixed Income	—	262,329	—	262,329	—	262,329
Common Collective Trust - Real Estate	—	1,728	—	1,728	15,701	17,429
Hedge Funds	—	—	—	—	23,625	23,625
Total investments measured at fair value	$ —	$ 377,017	$ —	$ 377,017	$ 39,326	$ 416,343

Pension Plan	December 31, 2016					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV [a]	Total Investments
AXA Equitable General Fixed Income	$ —	$ 1,325	$ —	$ 1,325	$ —	$ 1,325
Common Collective Trust - Cash and Cash Equivalents	—	5,307	—	5,307	—	5,307
Common Collective Trust - Equity	—	101,020	—	101,020	—	101,020
Common Collective Trust - Fixed Income	—	209,815	—	209,815	—	209,815
Common Collective Trust - Real Estate	—	2,349	—	2,349	15,563	17,912
Hedge Funds	—	—	—	—	29,316	29,316
Total investments measured at fair value	$ —	$ 319,816	$ —	$ 319,816	$ 44,879	$ 364,695

(a) Certain investments that are measured at fair value using Net Asset Value “NAV” per share (or its equivalent) for practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in these tables for these investments are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the reconciliation of changes in the plan’s benefit obligations and fair value of plan assets above.

Non-pension Defined Benefit Postretirement Healthcare Plans	December 31, 2017					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV [a]	Total Investments
Cash and Cash Equivalents	$ 4,671	$ —	$ —	$ 4,671	$ —	$ 4,671
Equity Securities	1,374	—	—	1,374	—	1,374
Intermediate-term Bond	—	2,576	—	2,576	—	2,576
Total investments measured at fair value	$ 6,045	$ 2,576	$ —	$ 8,621	$ —	$ 8,621

Non-pension Defined Benefit Postretirement Healthcare Plans	December 31, 2016					
	Level 1	Level 2	Level 3	Total Investments Measured at Fair Value	NAV [(a)]	Total Investments
Cash and Cash Equivalents	$ 111	$ —	—	$ 111	—	$ 111
Equity Securities	1,154	—	—	$ 1,154	—	1,154
Registered Investment Company Trust - Money Market Mutual Fund	—	4,732	—	$ 4,732	—	4,732
Intermediate-term Bond	—	2,473	—	$ 2,473	—	2,473
Total investments measured at fair value	$ 1,265	$ 7,205	$ —	$ 8,470	$ —	$ 8,470

(a) Certain investments that are measured at fair value using Net Asset Value "NAV" per share (or its equivalent) for practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in these tables for these investments are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the reconciliation of changes in the plans' benefit obligations and fair value of plan assets above.

Additional information about assets of the benefit plans, including methods and assumptions used to estimate the fair value of these assets, is as follows:

Cash and Cash Equivalents: This represents an investment in Invesco Treasury Portfolio, which is a short-term investment trust, as well as an investment in Northern Institutional Government Assets Portfolio, which is described as a government money market fund. As shares held reflect quoted prices in an active market, they are categorized as Level 1.

Equity Securities: These represent investments in a combination of equity positions for mainly large cap core allocation and Exchange Trade Funds (ETFs) for diversification into the other sectors of the economy. ETFs are a basket of securities traded like individual stocks on the exchange. Value of equity securities held at year end are based on published market quotations of active markets. The ETF funds can be redeemed on a daily basis at their market price and have no redemption restrictions. As shares held reflect quoted prices in an active market, they are categorized as Level 1.

Intermediate-term bond: This is comprised of a diversified pool of high quality, individual municipal bonds. Pricing is evaluated using multi-dimensional relational models, as well as a series of matrices using Standard Inputs, including Municipal Securities Rule Making Board (MSRB) reported trades and material event notices, plus Municipal Market Data (MMD) benchmark yields and new issue data. As the models use observable inputs and standard data, the investments are categorized as Level 2.

AXA Equitable General Fixed Income Fund: This fund is a diversified portfolio, primarily composed of fixed income instruments. Assets are invested in long-term holdings, such as commercial, agricultural and residential mortgages, publicly traded and privately placed bonds and real estate as well as short-term bonds. Fair values of mortgage loans are measured by discounting future contractual cash flows to be received on the mortgage loans using interest rates of loans with similar characteristics. The discount rate is derived from taking the appropriate U.S. Treasury rate with a like term. The fair value of public fixed maturity securities are generally based on prices obtained from independent valuation service providers with reasonableness prices compared with directly observable market trades. The fair value of privately placed securities are determined using a discounted cash flow model. These models use observable inputs with a discount rate based upon the average of spread surveys collected from private market intermediaries and industry sector of the issuer. The Plan's investments in the AXA Equitable General Fixed Income Fund are categorized as Level 2.

Common Collective Trust Funds: These funds are valued based upon the redemption price of units held by the Plan, which is based on the current fair value of the common collective trust funds' underlying assets. Unit values are determined by the financial institution sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation dates. The Plan's investments in common collective trust funds, with the exception of shares of the common collective trust-real estate are categorized as Level 2.

Common Collective Trust-Real Estate Fund: This fund is valued based on various factors of the underlying real estate properties, including market rent, market rent growth, occupancy levels, etc. As part of the trustee's valuation process, properties are externally appraised generally on an annual basis. The appraisals are conducted by reputable independent appraisal firms and signed by appraisers that are members of the Appraisal Institute, with professional designation of Member, Appraisal Institute. All external appraisals are performed in accordance with the Uniform Standards of Professional Appraisal

Practices. We receive monthly statements from the trustee, along with the annual schedule of investments and rely on these reports for pricing the units of the fund. The funds without participant withdrawal limitations are categorized as Level 2.

The following investments are measured at NAV and are not classified in the fair value hierarchy, in accordance with accounting guidance.

Common Collective Trust-Real Estate Fund: This is the same fund as above except that certain of the funds' assets contain participant withdrawal policies with restrictions on redemption and are therefore not included in the fair value hierarchy.

Hedge Funds: These funds represent investments in other investment funds that seek a return utilizing a number of diverse investment strategies. The strategies, when combined aim to reduce volatility and risk while attempting to deliver positive returns under all market conditions. Amounts are reported on a one-month lag. The fair value of hedge funds is determined using net asset value per share based on the fair value of the hedge fund's underlying investments. Generally, shares may be redeemed at the end of each quarter, with a 65 day notice and are limited to a percentage of total net asset value of the fund. The net asset values are based on the fair value of each fund's underlying investments. There are no unfunded commitments related to these hedge funds.

Other Plan Information

The following tables provide a reconciliation of the employee benefit plan obligations, fair value of assets and amounts recognized in the Consolidated Balance Sheets, components of the net periodic expense and elements of AOCI (in thousands):

Benefit Obligations

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
As of December 31,	2017	2016	2017	2016	2017	2016
Change in benefit obligation:						
Projected benefit obligation at beginning of year	$ 440,179	$ 356,575	$ 43,869	$ 40,219	$ 68,023	$ 48,077
Transfer from SourceGas Acquisition	—	75,254	—	—	—	15,091
Service cost	7,034	7,619	2,937	2,099	2,300	1,757
Interest cost	15,520	15,743	1,276	1,257	2,141	1,942
Actuarial (gain) loss [(a)]	36,661	7,001	247	2,049	(396)	2,808
Amendments	—	—	—	—	265	2,203
Benefits paid	(24,669)	(22,013)	(3,217)	(1,755)	(4,332)	(4,965)
Plan participants' contributions	—	—	—	—	1,338	1,110
Projected benefit obligation at end of year	$ 474,725	$ 440,179	$ 45,112	$ 43,869	$ 69,339	$ 68,023

(a) Increase from 2016 is primarily the result of a decrease in the discount rate.

Employee Benefit Plan Assets

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans [(a)]	
As of December 31,	2017	2016	2017	2016	2017	2016
Change in fair value of plan assets:						
Beginning fair value of plan assets	$ 364,695	$ 288,622	$ —	$ —	$ 8,470	$ 4,681
Transfer from SourceGas Acquisition	—	53,067	—	—	—	3,340
Investment income (loss)	48,617	30,819	—	—	120	256
Employer contributions	27,700	14,200	3,217	1,755	3,025	4,048
Retiree contributions	—	—	—	—	1,338	1,110
Benefits paid	(24,669)	(22,013)	(3,217)	(1,755)	(4,332)	(4,965)
Ending fair value of plan assets	$ 416,343	$ 364,695	$ —	$ —	$ 8,621	$ 8,470

(a) Assets of VEBAs and Grantor Trust.

The funded status of the plans and the amounts recognized in the Consolidated Balance Sheets at December 31 consist of (in thousands):

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2017	2016	2017	2016	2017	2016
Regulatory assets	$ 72,756	$ 66,640	$ —	$ —	$ 11,507	$ 11,401
Current liabilities	$ —	$ —	$ 1,372	$ 1,583	$ 4,423	$ 4,360
Non-current assets	$ —	$ —	$ —	$ —	$ 69	$ 21
Non-current liabilities	$ 58,381	$ 75,484	$ 43,739	$ 42,286	$ 56,365	$ 55,214
Regulatory liabilities	$ 5,232	$ 5,195	$ —	$ —	$ 3,334	$ 3,419

Accumulated Benefit Obligation

As of December 31 (in thousands)	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2017	2016	2017	2016	2017	2016
Accumulated Benefit Obligation [a]	$ 450,394	$ 416,786	$ 41,243	$ 32,090	$ 69,339	$ 68,023

(a) The Defined Benefit Pension Plan Accumulated Benefit Obligation for 2017 and 2016 represents the obligation for the merged Black Hills Retirement Plan. The Non-pension Defined Benefit Retirement Healthcare Plans Accumulated Benefit Obligation for 2017 and 2016 represents that obligation for the five postretirement plans maintained by BHC.

Components of Net Periodic Expense

Net periodic expense consisted of the following for the year ended December 31 (in thousands):

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plans		
	2017	2016	2015	2017	2016	2015	2017	2016	2015
Service cost	$ 7,034	$ 7,619	$ 6,093	$ 1,546	$ 1,335	$ 1,380	$ 2,300	$ 1,757	$ 1,808
Interest cost	15,520	15,743	15,522	1,276	1,257	1,455	2,141	1,942	1,801
Expected return on assets	(24,517)	(23,062)	(19,470)	—	—	—	(315)	(279)	(131)
Net amortization of prior service cost	58	58	58	2	2	2	(411)	(428)	(428)
Recognized net actuarial loss (gain)	4,007	7,173	11,037	1,001	829	1,081	499	335	408
Settlement expense[a]	—	10	—	—	—	—	—	—	—
Net periodic expense	$ 2,102	$ 7,541	$ 13,240	$ 3,825	$ 3,423	$ 3,918	$ 4,214	$ 3,327	$ 3,458

(a) Settlement expense is the result of lump-sum payments on the SourceGas Retirement Plan in excess of interest and service costs for the year.

AOCI

For defined benefit plans, amounts included in AOCI, after-tax, that have not yet been recognized as components of net periodic benefit cost at December 31 were as follows (in thousands):

	Defined Benefit Pension Plan		Supplemental Non-qualified Defined Benefit Plans		Non-pension Defined Benefit Postretirement Healthcare Plans	
	2017	2016	2017	2016	2017	2016
Net (gain) loss	$ 10,056	$ 8,472	$ 6,639	$ 7,132	$ 1,309	$ 1,595
Prior service cost (gain)	21	31	4	5	(542)	(694)
Reclassification of certain tax effects from AOCI	2,087	—	1,371	—	158	—
Total AOCI	$ 12,164	$ 8,503	$ 8,014	$ 7,137	$ 925	$ 901

The amounts in AOCI, Regulatory assets or Regulatory liabilities, after-tax, expected to be recognized as a component of net periodic benefit cost during calendar year 2018 are as follows (in thousands):

	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Plans	Non-pension Defined Benefit Postretirement Healthcare Plans
Net loss	$ 5,610	$ 650	$ 141
Prior service cost (credit)	38	1	(258)
Total net periodic benefit cost expected to be recognized during calendar year 2018	$ 5,648	$ 651	$ (117)

Assumptions

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plans		
Weighted-average assumptions used to determine benefit obligations:	2017	2016	2015	2017	2016	2015	2017	2016	2015
Discount rate	3.71%	4.27%	4.58%	3.56%	4.02%	4.28%	3.60%	3.96%	4.17%
Rate of increase in compensation levels	3.43%	3.47%	3.51%	5.00%	5.00%	5.00%	N/A	N/A	N/A

	Defined Benefit Pension Plan			Supplemental Non-qualified Defined Benefit Plans			Non-pension Defined Benefit Postretirement Healthcare Plans		
Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2017	2016	2015	2017	2016	2015	2017	2016	2015
Discount rate [(a)]	4.27%	4.50%	4.19%	4.02%	4.28%	4.19%	4.05%	4.18%	3.82%
Expected long-term rate of return on assets [(b)]	6.75%	6.87%	6.75%	N/A	N/A	N/A	3.88%	3.83%	3.00%
Rate of increase in compensation levels	3.47%	3.42%	3.76%	5.00%	5.00%	5.00%	N/A	N/A	N/A

(a) The estimated discount rate for the merged Black Hills Retirement Plan is 3.71% for the calculation of the 2018 net periodic pension costs.
(b) The expected rate of return on plan assets is 6.25% for the calculation of the 2018 net periodic pension cost.

The healthcare benefit obligation was determined at December 31 as follows:

	2017	2016 [(a)]
Trend Rate - Medical		
Pre-65 for next year - All Plans	7.00%	6.10%
Pre-65 Ultimate trend rate - Black Hills Corp	4.50%	4.50%
Trend Year	2027	2024
Post-65 for next year - All Plans	5.00%	5.10%
Post-65 Ultimate trend rate - Black Hills Corp	4.50%	4.50%
Trend Year	2026	2023

(a) The 2016 Medical Trend Rates include the two additional non-pension defined benefit postretirement plans from SourceGas.

We do not pre-fund our supplemental plans or three of the five healthcare plans. The table below shows the expected impacts of an increase or decrease to our healthcare trend rate for our Healthcare Plans (in thousands):

Change in Assumed Trend Rate	Impact on December 31, 2017 Accumulated Postretirement Benefit Obligation	Impact on 2018 Service and Interest Cost
Increase 1%	$ 2,968	$ 148
Decrease 1%	$ (2,534)	$ (126)

Beginning in 2016, the Company changed the method used to estimate the service and interest cost components of the net periodic pension, supplemental non-qualified defined benefit and other postretirement benefit costs. See “Pension and Postretirement Benefit Obligations” within our Critical Accounting Policies in Item 7 on Form 10-K for additional details.

The following benefit payments, which reflect future service, are expected to be paid (in thousands):

	Defined Benefit Pension Plan	Supplemental Non-qualified Defined Benefit Plans	Non-Pension Defined Benefit Postretirement Healthcare Plans
2018	$ 21,495	$ 1,372	$ 5,633
2019	$ 23,238	$ 1,617	$ 6,231
2020	$ 27,203	$ 1,558	$ 6,328
2021	$ 26,990	$ 1,773	$ 6,072
2022	$ 27,427	$ 1,872	$ 5,920
2023-2027	$ 154,771	$ 11,304	$ 26,365

(19) COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreements

Through our subsidiaries, we have the following significant long-term power purchase contracts with non-affiliated third-parties:

- Black Hills Wyoming sold its CTII 40 MW natural gas-fired generating unit to the City of Gillette, Wyoming on September 3, 2014. Under the terms of the sale, Black Hills Wyoming entered into ancillary agreements to operate CTII, provide use of shared facilities including a ground lease and dispatch generation services. In addition, the agreement includes a 20-year economy energy PPA that contains a sharing arrangement in which the parties share the savings of wholesale power purchases made when market power prices are less than the cost of operating the generating unit.

- South Dakota Electric's PPA with PacifiCorp, expiring December 31, 2023, for the purchase of 50 MW of electric capacity and energy from PacifiCorp's system. The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants.

- South Dakota Electric's firm point-to-point transmission service agreement with PacifiCorp that expires December 31, 2023. The agreement provides 50 MW of capacity and energy to be transmitted annually by PacifiCorp.

- Wyoming Electric's PPA with Duke Energy's Happy Jack wind site, expiring September 3, 2028, provides up to 30 MW of wind energy from Happy Jack to Wyoming Electric. Under a separate intercompany agreement, Wyoming Electric sells 50% of the facility output to South Dakota Electric.

- Wyoming Electric's PPA with Duke Energy's Silver Sage wind site, expiring September 30, 2029, provides up to 30 MW of wind energy. Under a separate intercompany agreement, Wyoming Electric sells 20 MW of energy from Silver Sage to South Dakota Electric.

- Colorado Electric's REPA with AltaGas expiring October 16, 2037, provides up to 14.5 MW of wind energy from the Busch Ranch Wind Farm in which Colorado Electric owns a 50% undivided ownership interest.

Costs under these power purchase contracts for the years ended December 31 were as follows (in thousands):

	2017	2016	2015
PPA with PacifiCorp	$ 13,218	$ 12,221	$ 13,990
Transmission services agreement with PacifiCorp	$ 1,671	$ 1,428	$ 1,213
PPA with Happy Jack	$ 3,846	$ 3,836	$ 3,155
PPA with Silver Sage	$ 4,934	$ 4,949	$ 4,107
Busch Ranch Wind Farm	$ 1,966	$ 2,071	$ 1,734
PPAs with Cargill [(a)]	$ —	$ 10,995	$ 16,112

(a) PPAs with Cargill expired on December 31, 2016.

Other Gas Supply Agreements

Our Utilities also purchase natural gas, including transportation and storage capacity to meet customers' needs, under short-term and long-term purchase contracts. These contracts extend to 2044.

Purchase Commitments

We maintain natural gas supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated baseload gas volumes are established prior to the beginning of the month under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month based on requirements in accordance with the terms of the individual contract.

Our Gas Utilities segment has commitments to purchase physical quantities of natural gas under contracts indexed to various forward natural gas price curves. A portion of our gas purchases are purchased under evergreen contracts and are therefore, for purposes of this disclosure, carried out for 60 days. At December 31, 2017, the long-term commitments to purchase quantities of natural gas under contracts indexed to the following forward indices were as follows (in MMBtus):

	CIG Rockies	NNG-Ventura	NWPL-Wyoming	EP-San Juan Basin	Other
2018	5,784,827	3,759,500	1,298,970	278,600	30,562
2019	5,776,125	3,704,300	786,470	287,000	—
2020	75,075	3,660,000	—	206,600	—
2021	—	3,650,000	—	—	—
2022	—	1,810,000	—	—	—

Purchases under these contracts totaled $65 million, $31 million and $48 million for 2017, 2016 and 2015, respectively.

The following is a schedule of unconditional purchase obligations required under the power purchase, transmission services, coal and natural gas transportation and storage agreements (in thousands):

	Power Purchase Agreements	Transportation, storage and coal agreements
2018	$ 28,041	$ 121,485
2019	$ 6,837	$ 122,351
2020	$ 6,837	$ 117,332
2021	$ 6,203	$ 107,918
2022	$ 6,203	$ 87,393
Thereafter	$ 6,204	$ 202,831

Future Purchase Agreement - Related Party

Wyoming Electric's PPA for 60 MW of capacity and energy from Black Hills Wyoming's Wygen I generating facility expiring on December 31, 2022, includes an option for Wyoming Electric to purchase Black Hills Wyoming's ownership in the Wygen I facility. The purchase price related to the option is $2.6 million per MW which is the equivalent per MW of the pre-construction estimated cost of the Wygen III plant, which was completed in April 2010. This option purchase price is adjusted for capital additions and reduced by an amount equal to annual depreciation based on a 35-year life starting January 1, 2009. The purchase option would be subject to WPSC and FERC approval in order to obtain regulatory treatment.

Power Sales Agreements

Through our subsidiaries, we have the following significant long-term power sales contracts with non-affiliated third-parties:

- During periods of reduced production at Wygen III in which MDU owns a portion of the capacity, or during periods when Wygen III is off-line, MDU will be provided with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU. This agreement expires January 31, 2023.

- South Dakota Electric has an agreement to serve MDU capacity and energy up to a maximum of 50 MW in excess of Wygen III ownership. This agreement expires December 31, 2023.

- During periods of reduced production at Wygen III in which the City of Gillette owns a portion of the capacity, or during periods when Wygen III is off-line, we will provide the City of Gillette with its first 23 MW from our other generating facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, which expires September 3, 2019, South Dakota Electric will also provide the City of Gillette their operating component of spinning reserves.

- South Dakota Electric has a PPA with MEAN expiring May 31, 2023. This contract is unit-contingent on up to 10 MW from Neil Simpson II and up to 10 MW from Wygen III based on the availability of these plants. The capacity purchase requirements decrease over the term of the agreement.

- South Dakota Electric has an agreement from January 1, 2017 through December 31, 2021 to provide 50 MW of energy to Cargill (assigned to Macquarie on January 3, 2018) during heavy and light load timing intervals.

Related Party Lease

Colorado Electric's PPA with Black Hills Colorado IPP expiring on December 31, 2031, provides 200 MW of power to Colorado Electric from Black Hills Colorado IPP's combined-cycle turbines. This PPA is accounted for as a capital lease whereby Colorado Electric, as lessee, has included the combined-cycle turbines as property, plant and equipment along with the related lease obligation and Black Hills Colorado IPP, as lessor, has recorded a lease receivable. Segment revenue and expenses associated with the PPA have been impacted by the lease accounting. The effect of the lease accounting is eliminated in corporate consolidations.

Reimbursement Agreement

We have a reimbursement agreement in place with Wells Fargo on behalf of Wyoming Electric for the 2009A bonds of $10 million due in 2027 and the 2009B bonds of $7.0 million due in 2021. In the case of default, we hold the assumption of liability for drawings on Wyoming Electric's Letter of Credit attached to these bonds.

Environmental Matters

We are subject to costs resulting from a number of federal, state and local laws and regulations which affect future planning and existing operations. Laws and regulations can result in increased capital expenditures, operating and other costs as a result of compliance, remediation and monitoring obligations. Due to the environmental issues discussed below, we may be required to modify, curtail, replace or cease operating certain facilities or operations to comply with statutes, regulations and other requirements of regulatory bodies.

Solid Waste Disposal

Various materials used at our facilities are subject to disposal regulations. Our Osage plant, permanently retired on March 21, 2014, had an on-site ash impoundment that was near capacity. An application to close the impoundment was approved on April 13, 2012. Site closure work was completed in 2013 with the state providing closure certification in 2014. Post closure monitoring activities will continue for 30 years following the closure certification date.

In September 2013, Osage also received a permit to close the small industrial rubble landfill. Site work was completed with the state providing closure certification in 2014. Post closure monitoring will continue for 30 years following the closure certification date.

Our W.N. Clark plant, which has been retired, previously delivered coal ash to a permitted, privately-owned landfill. While we do not believe that any substances from our solid waste disposal activities will pollute underground water, we can provide no assurance that pollution will not occur over time. In this event, we could incur material costs to mitigate any resulting damages.

Reclamation Liability

For our Pueblo Airport Generation site, we posted a bond of $4.1 million with the State of Colorado to cover the costs of remediation for a waste water containment pond permitted to provide wastewater storage and processing for this zero discharge facility. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

Under its land lease for Busch Ranch, Colorado Electric is required to reclaim all land where it has placed wind turbines. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

Under its mining permit, WRDC is required to reclaim all land where it has mined coal reserves. The reclamation liability is recorded at the present value of the estimated future cost to reclaim the land.

See Note 8 for additional information.

Manufactured Gas Processing

As a result of the Aquila Transaction, we acquired whole and partial liabilities for several former manufactured gas processing sites in Nebraska and Iowa which were previously used to convert coal to natural gas. The acquisition provided for an insurance recovery, now valued at $1.5 million recorded in Other assets, non-current on our Consolidated Balance Sheets, which will be used to help offset remediation costs. We also have a $1.0 million regulatory asset for manufactured gas processing sites; see Note 1. The remediation cost estimate could change materially due to results of further investigations, actions of environmental agencies or the financial viability of other responsible parties.

As of December 31, 2017, our estimated liabilities for Iowa's MGP sites currently range from approximately $2.6 million to $6.1 million for which we had $2.6 million accrued for remediation of sites as of December 31, 2017 included in Other deferred credits and other liabilities on our Consolidated Balance Sheets.

For additional information on environmental matters, see Item 1 in this Annual Report on Form 10-K.

Legal Proceedings

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in the consolidated financial statements to satisfy alleged liabilities are adequate in light of the probable and estimable contingencies. However, there can be no assurance that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed, and to comply with applicable laws and regulations will not exceed the amounts reflected in the consolidated financial statements.

In the normal course of business, we enter into agreements that include indemnification in favor of third parties, such as information technology agreements, purchase and sale agreements and lease contracts. We have also agreed to indemnify our directors, officers and employees in accordance with our articles of incorporation, as amended. Certain agreements do not contain any limits on our liability and therefore, it is not possible to estimate our potential liability under these indemnifications. In certain cases, we have recourse against third parties with respect to these indemnities. Further, we maintain insurance policies that may provide coverage against certain claims under these indemnities.

(20) GUARANTEES

We have entered into various agreements providing financial or performance assurance to third parties on behalf of certain of our subsidiaries. The agreements include indemnification for reclamation and surety bonds and a contract performance guarantee.

We had the following guarantees in place as of (in thousands):

Nature of Guarantee	Maximum Exposure at December 31, 2017	Expiration
Indemnification for subsidiary reclamation/surety bonds [(a)]	$ 58,221	Ongoing
	$ 58,221	

(a) We have guarantees in place for reclamation and surety bonds for our subsidiaries. The guarantees were entered into in the normal course of business. To the extent liabilities are incurred as a result of activities covered by the surety bonds, such liabilities are included in our Consolidated Balance Sheets.

(21) DISCONTINUED OPERATIONS

Results of operations for discontinued operations have been classified as Income from discontinued operations, net of income taxes in the accompanying Consolidated Statements of Income. Current assets, noncurrent assets, current liabilities and non-current liabilities of the discontinued operations have been reclassified and reflected on the accompanying Consolidated Balance Sheets as “Current assets held for sale,” “Noncurrent assets held for sale,” “Current liabilities held for sale,” and “Noncurrent liabilities held for sale”, respectively. Prior periods relating to our discontinued operations have also been reclassified to reflect consistency within our consolidated financial statements.

Oil and Gas Segment

On November 1, 2017, the BHC Board of Directors approved a complete divestiture of our Oil and Gas segment. As of February 23, 2018, we have either closed transactions or signed contracts to sell more than 90% of our oil and gas properties. We have executed agreements to sell all our operated properties and have only non-operated assets left to divest. We plan to conclude the sale of all of our remaining assets by mid-year 2018.

We are in the process of divesting our Oil and Gas segment; therefore, we performed a fair value assessment of the assets and liabilities classified as held for sale. We evaluated our disposal groups classified as held for sale based on the lower of carrying value or fair value less cost to sell. The market approach was based on our recent fourth quarter 2017 sale of our Powder River Basin assets and pending sale transactions of our other properties.

There is risk involved when determining the fair value of assets, as there may be unforeseen events and changes in circumstances and market conditions that have a material impact on the estimated amount and timing of future cash flows. In addition, the fair value of the assets and liabilities could be different using different estimates and assumptions in the valuation techniques used. We believe that the estimates used in calculating the fair value of our assets and liabilities held for sale are reasonable based on the information that was known when the estimates were made.

At December 31, 2017, the fair value of our held for sale assets was less than our carrying value, which required an after-tax write down of $13 million. There were no adjustments made to the fair value of our held for sale liabilities.

Total assets and liabilities of BHEP at December 31, 2017 have been classified as Current assets held for sale and Current liabilities held for sale on the accompanying Consolidated Balance Sheets due to the expected final disposals occurring by mid-year 2018. Held for sale assets and liabilities at December 31, 2016 are classified as current and non-current.

	As of	
(in thousands)	December 31, 2017	December 31, 2016
Other current assets	$ 10,360	$ 11,401
Derivative assets, current and noncurrent	—	153
Deferred income tax assets, noncurrent, net	16,966	26,329
Property, plant and equipment, net	56,916	82,812
Other current liabilities	(18,966)	(9,834)
Derivative liabilities, current and noncurrent	—	(1,586)
Other noncurrent liabilities	(22,808)	(22,803)
Net assets	$ 42,468	$ 86,472

At December 31, 2017 and 2016, the Oil and Gas segment’s net deferred tax assets were primarily comprised of basis differences on oil and gas properties.

BHEP’s accrued liabilities at December 31, 2017 and 2016 consisted primarily of accrued royalties, payroll and property taxes. Other liabilities at December 31, 2017 and 2016 consisted primarily of ARO obligations relating to plugging and abandonment of oil and gas wells.

Operating results of the Oil and Gas segment included in Discontinued operations on the accompanying Consolidated Statements of Income were as follows (in thousands):

	For the Years Ended		
	December 31, 2017	December 31, 2016	December 31, 2015
Revenue	$ 25,382	$ 34,058	$ 43,283
Operations and maintenance	22,872	27,187	35,461
Depreciation, depletion and amortization	7,521	13,510	28,838
Impairment of long-lived assets	20,385	106,957	249,608
Total operating expenses	50,778	147,654	313,907
Operating (loss)	(25,396)	(113,596)	(270,624)
Interest income (expense), net	181	698	931
Other income (expense), net	(297)	110	(378)
Impairment of equity investments	—	—	(4,405)
Income tax benefit (expense)	8,413	48,626	100,817
(Loss) from discontinued operations	$ (17,099)	$ (64,162)	$ (173,659)

Full Cost Accounting

Historically, we used the full cost method of accounting for oil and gas production activities. Under the full cost method, costs related to acquisition, exploration and estimated future expenditures to be incurred in developing proved reserves as well as estimated reclamation and abandonment costs, net of estimated salvage values are capitalized. These costs are amortized using a unit-of-production method based on volumes produced and proved reserves. Any conveyances of properties, including gains or losses on abandonment of properties, are typically treated as adjustments to the cost of the properties with no gain or loss recognized.

Costs directly associated with unproved properties and major development projects, if any, are excluded from the costs to be amortized. These excluded costs are subsequently included within the costs to be amortized when it is determined whether or not proved reserves can be assigned to the properties. The properties excluded from the costs to be amortized are assessed for impairment at least annually and any amount of impairment is added to the costs to be amortized.

Under the full cost method, net capitalized costs, less accumulated amortization and related deferred income taxes, are subject to a ceiling test which limits the pooled costs to the aggregate of the discounted value of future net revenue attributable to proved natural gas and crude oil reserves using a discount rate defined by the SEC, plus the lower of cost or market value of unevaluated properties. Future net cash flows are estimated based on SEC-defined end-of-period commodity prices adjusted for contracted price changes and held constant for the life of the reserves. An average price is calculated using the price at the first day of each month for each of the preceding 12 months. If the net capitalized costs exceed the full cost “ceiling” at period end, a permanent non-cash write-down would be charged to earnings in that period.

Impairment of long-lived assets

As discussed above, at December 31, 2017, the fair value of our held for sale assets was less than our carrying value, which required a write down of $20 million. There were no adjustments made to the fair value of our held for sale liabilities.

As a result of continued low commodity prices throughout 2016, we recorded non-cash ceiling test impairments of oil and gas assets totaling approximately $92 million for the year ended December 31, 2016. In determining the ceiling value of our assets, we utilized the average of the quoted prices from the first day of each month from the previous 12 months. For natural gas, the average NYMEX price was $2.48 per Mcf, adjusted to $2.25 per Mcf at the wellhead; for crude oil, the average NYMEX price was $42.75 per barrel, adjusted to $37.35 per barrel at the wellhead.

In 2015, we recorded a non-cash ceiling test impairment of oil and gas assets totaling approximately $250 million for the year ended December 31, 2015. In determining the ceiling value of our assets, we utilized the average of the quoted prices from the

first day of each month from the previous 12 months. For natural gas, the average NYMEX price was $2.59 per Mcf, adjusted to $1.27 per Mcf at the wellhead; for crude oil, the average NYMEX price was $50.28 per barrel, adjusted to $44.72 per barrel at the wellhead.

During the second quarter of 2016, certain non-core assets were identified that were not suitable for inclusion in a possible Cost of Service Gas Program. We assessed these assets for impairment in accordance with ASC 360. We valued the assets applying a market method approach utilizing assumptions consistent with similar known and measurable transactions and determined that the carrying amount exceeded the fair value. As a result, we recorded a pre-tax impairment of depreciable properties at June 30, 2016 of $14 million, in addition to the ceiling test impairments noted above.

Equity investments in unconsolidated subsidiaries

BHEP owned a 25% interest in a pipeline and gathering system, accounted for under the equity method of accounting. During the second quarter of 2015, due to sustained low commodity prices, recurring operating losses and future expectations we reviewed this investment interest for impairment utilizing the other-than-temporary impairment model under ASC 820, *Fair Value Measurements*. We valued the investment applying a market method approach utilizing assumptions consistent with similar known and measurable transactions. The carrying amount of this equity method investment exceeded the fair value, and we concluded the decline was considered to be other than temporary. As a result, we recorded a pre-tax impairment loss in 2015 of $4.4 million, the difference between the carrying amount and the fair value of the investment. In December of 2015, we sold our 25% interest in this pipeline and gathering system.

(22) OIL AND GAS RESERVES (Unaudited)

On November 1, 2017, we initiated the process of divesting all Oil and Gas segment assets in order to fully exit the oil and gas business. On November 1, 2017, we stopped the use of the full-cost method of accounting for our oil and gas business. The assets and liabilities have been classified as held for sale and the results of operations are included in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. As a result, our oil and gas reserves are no longer considered significant. For more information, see Note 21.

Costs Incurred

Following is a summary of costs incurred in oil and gas property acquisition, exploration and development during the years ended December 31 (in thousands):

	2016	2015
Acquisition of properties:		
Proved	$ —	$ 1,407
Unproved	910	669
Exploration costs	1,102	35,434
Development costs	4,657	128,998
Asset retirement obligations incurred	—	566
Total costs incurred	$ 6,669	$ 167,074

Reserves

The following table summarizes BHEP's quantities of proved developed and undeveloped oil, natural gas and NGL reserves, estimated using SEC-defined product prices, as of December 31, 2016 and 2015 and a reconciliation of the changes between these dates. The summary information presented for our estimated proved developed and undeveloped crude oil, natural gas, and NGL reserves and the 10% discounted present value of estimated future net revenues is based on reports prepared by Cawley Gillespie & Associates (CG&A), an independent consulting and engineering firm located in Fort Worth, Texas. CG&A is a Texas Registered Engineering Firm. Our primary contact at CG&A is Mr. Zane Meekins. Mr. Meekins has been practicing consulting petroleum engineering since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas, a member of the Society of Petroleum Evaluation Engineers (SPEE), and has over 30 years of practical experience in petroleum engineering and over 28 years of experience in the estimation and evaluation of reserves. Reserves were determined consistent with SEC requirements using a 12-month average product price calculated using the first-day-of-the-month price for each of the 12 months in the reporting period held constant for the life of the properties. Reserves for crude oil, natural gas, and NGLs

are reported separately and then combined for a total MMcfe (where oil and NGLs in Mbbl are converted to an MMcfe basis by multiplying Mbbl by six). Such reserve estimates were inherently imprecise and may be subject to revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

Minor differences in amounts may result in the following tables relating to oil and gas reserves due to rounding.

	2016			2015		
	Oil	Gas	NGL	Oil	Gas	NGL
	(in Mbbls of oil and NGL, and MMcf of gas)					
Proved developed and undeveloped reserves:						
Balance at beginning of year	3,450	73,412	1,752	4,276	65,440	1,720
Production [(a)]	(319)	(9,430)	(133)	(371)	(10,058)	(102)
Sales	(570)	(1,291)	(17)	(11)	(828)	—
Additions - extensions and discoveries	3	52	—	199	24,462	232
Revisions to previous estimates	(322)	(8,173)	110	(643)	(5,604)	(98)
Balance at end of year	2,242	54,570	1,712	3,450	73,412	1,752
Proved developed reserves at end of year included above	2,242	54,570	1,712	3,436	73,390	1,752
Proved undeveloped reserves at the end of year included in above	—	—	—	14	22	—
NYMEX prices	$ 42.75	$ 2.48	$ — [(b)]	$ 50.28	$ 2.59	$ — [(b)]
Well-head reserve prices[(c)]	$ 37.35	$ 2.25	$ 11.92	$ 44.72	$ 1.27	$ 18.96

(a) Production for reserve calculations did not include volumes for natural gas liquids (NGLs) for historical periods.

(b) A specific NYMEX price for NGL was not available. Market prices for NGL are broken down by various liquid components, including ethane, propane, isobutane, normal butane, and natural gasoline. Each of these components is traded as an index. Ethane was not being recovered at any of the facilities that process our natural gas production.

(c) For reserves purposes, costs to gather gas previously netted from the gas price were reclassified into operating expenses in 2016, with approximate rates of $1.54/Mcf for Piceance, $0.92/Mcf for San Juan and $0.53/Mcf for all others. The sales price for natural gas was adjusted for transportation costs and other related deductions when applicable.

Capitalized Costs

Following is information concerning capitalized costs for the years ended December 31 (in thousands):

	2016	2015
Unproved oil and gas properties	$ 18,547	$ 47,254
Proved oil and gas properties	1,043,558	1,008,466
Gross capitalized costs	1,062,105	1,055,720
Accumulated depreciation, depletion and amortization and valuation allowances	(1,000,091)	(888,775)
Net capitalized costs	$ 62,014	$ 166,945

Results of Operations

For more on oil and gas producing activities included in discontinued operations, see Note 21. Following is a summary of results of operations for producing activities for the years ended December 31 (in thousands):

	2016	2015
Revenue	$ 34,058	$ 43,283
Production costs	17,231	19,762
Depreciation, depletion and amortization	12,574	28,062
Impairment of long-lived assets	106,957	249,608
Total costs	136,762	297,432
Results of operations from producing activities before tax	(102,704)	(254,149)
Income tax benefit (expense)	37,916	93,743
Results of operations from producing activities (excluding general and administrative costs and interest costs)	$ (64,788)	$ (160,406)

Unproved Properties

Unproved properties not subject to amortization at December 31, 2016 and 2015 consisted mainly of exploration costs on various existing work-in-progress projects as well as leasehold acquired through significant natural gas and oil property acquisitions and through direct purchases of leasehold. We capitalized approximately $0.9 million and $1.0 million of interest during 2016 and 2015, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full-cost pool.

The table below sets forth the cost of unproved properties excluded from the amortization base as of December 31, 2016 and notes the year in which the associated costs were incurred (in thousands):

	2016	2015	Prior	Total
Leasehold acquisition cost	$ 963	$ —	$ —	$ 963
Exploration cost	532	441	—	973
Capitalized interest	50	23	—	73
Total	$ 1,545	$ 464	$ —	$ 2,009

Standardized Measure of Discounted Future Net Cash Flows

Following is a summary of the standardized measure of discounted future net cash flows and changes relating to proved oil and gas reserves for the years ended December 31 (in thousands):

	2016	2015
Future cash inflows	$ 246,221	$ 295,173
Future production costs	(166,248)	(146,552)
Future development costs, including plugging and abandonment	(18,333)	(24,833)
Future net cash flows	61,640	123,788
10% annual discount for estimated timing of cash flows	(26,574)	(44,760)
Standardized measure of discounted future net cash flows	$ 35,066	$ 79,028

The following are the principal sources of change in the standardized measure of discounted future net cash flows during the years ended December 31 (in thousands):

	2016	2015
Standardized measure - beginning of year	$ 79,028	$ 183,022
Sales and transfers of oil and gas produced, net of production costs	(4,314)	(29,948)
Net changes in prices and production costs	(32,698)	(127,199)
Extensions, discoveries and improved recovery, less related costs	—	15,718
Changes in future development costs	1,825	(7,387)
Development costs incurred during the period	—	27,211
Revisions of previous quantity estimates	(7,477)	(6,941)
Accretion of discount	7,903	18,870
Net change in income taxes	—	5,682
Sales of reserves	(9,201)	—
Standardized measure - end of year	$ 35,066	$ 79,028

Changes in the standardized measure from “revisions of previous quantity estimates” were driven by reserve revisions, modifications of production profiles and timing of future development. For all years presented, we had minimal net reserve revisions to prior estimates due to performance. Production forecast modifications were generally made at the well level each year through the reserve review process. These production profile modifications were based on incorporation of the most recent production information and applicable technical studies. Timing of future development investments were reviewed each year and were often modified in response to current market conditions for items such as permitting and service availability.

(23) QUARTERLY HISTORICAL DATA (Unaudited)

The Company operates on a calendar year basis. The following tables set forth select unaudited historical operating results and market data for each quarter of 2017 and 2016.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2017				
Revenue	$ 547,528	$ 341,829	$ 335,611	$ 455,298
Operating income (loss)	$ 150,186	$ 69,796	$ 79,559	$ 117,195
Income (loss) from continuing operations	$ 81,715	$ 25,927	$ 32,898	$ 67,835
Income (loss) from discontinued operations	$ (1,569)	$ (616)	$ (1,300)	$ (13,614)
Net income attributable to noncontrolling interest	$ (3,623)	$ (3,116)	$ (3,935)	$ (3,568)
Net income (loss) available for common stock	$ 76,523	$ 22,195	$ 27,663	$ 50,653
Amounts attributable to common shareholders:				
Net income (loss) from continuing operations	$ 78,092	$ 22,811	$ 28,963	$ 64,267
Net income (loss) from discontinued operations	$ (1,569)	$ (616)	$ (1,300)	$ (13,614)
Net income (loss) available for common stock	$ 76,523	$ 22,195	$ 27,663	$ 50,653
Income (loss) per share for continuing operations - Basic	$ 1.47	$ 0.43	$ 0.54	$ 1.21
Income (loss) per share for discontinued operations - Basic	$ (0.03)	$ (0.01)	$ (0.02)	$ (0.26)
Earnings (loss) per share - Basic	$ 1.44	$ 0.42	$ 0.52	$ 0.95
Income (loss) per share for continuing operations - Diluted	$ 1.42	$ 0.41	$ 0.52	$ 1.17
Income (loss) per share for discontinued operations - Diluted	$ (0.03)	$ (0.01)	$ (0.02)	$ (0.25)
Earnings (loss) per share - Diluted	1.39	0.40	0.50	0.92
Dividends paid per share	$ 0.445	$ 0.445	$ 0.445	$ 0.475
Common stock prices - High	$ 67.02	$ 72.02	$ 71.01	$ 69.79
Common stock prices - Low	$ 60.02	$ 65.37	$ 67.08	$ 57.01

Income from continuing operations for each quarter of 2017 included external incremental acquisition and transaction costs. We incurred after-tax external incremental acquisition and transaction expenses of $0.9 million during the first quarter, $0.3 million during the second quarter, $0.2 million during the third quarter and $1.3 million during the fourth quarter.

Included within the Income (loss) from continuing operations in the fourth quarter of 2017 is a net tax benefit of $7.6 million from the impact of the TCJA, as well as a tax benefit of $4.1 million from a true-up to the filed 2016 SourceGas tax returns related to the SourceGas acquisition.

Included within the Loss from discontinued operations in the fourth quarter of 2017 is an after-tax non-cash impairment of oil and gas properties of $13.0 million.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts, dividends and common stock prices)			
2016				
Revenue	$ 441,584	$ 317,795	$ 324,147	$ 455,390
Operating income (loss)	$ 91,281	$ 63,725	$ 70,844	$ 110,330
Income (loss) from continuing operations	$ 45,320	$ 21,128	$ 24,964	$ 55,381
Income (loss) from discontinued operations	$ (5,270)	$ (17,845)	$ (7,080)	$ (33,967)
Net income attributable to noncontrolling interest	$ (48)	$ (2,614)	$ (3,753)	$ (3,246)
Net income (loss) available for common stock	$ 40,002	$ 669	$ 14,131	$ 18,168
Amounts attributable to common shareholders:				
Net income (loss) from continuing operations	45,272	18,514	21,211	52,135
Net income (loss) from discontinued operations	(5,270)	(17,845)	(7,080)	(33,967)
Net income (loss) available for common stock	40,002	669	14,131	18,168
Income (loss) per share for continuing operations - Basic	$ 0.88	$ 0.36	$ 0.41	$ 0.98
Income (loss) per share for discontinued operations - Basic	(0.10)	(0.35)	(0.14)	(0.64)
Earnings (loss) per share - Basic	$ 0.78	$ 0.01	$ 0.27	$ 0.34
Income (loss) per share for continuing operations - Diluted	$ 0.87	$ 0.35	$ 0.39	$ 0.96
Income (loss) per share for discontinued operations - Diluted	(0.10)	(0.34)	(0.13)	(0.63)
Earnings (loss) per share - Diluted	$ 0.77	$ 0.01	$ 0.26	$ 0.33
Dividends paid per share	$ 0.420	$ 0.420	$ 0.420	$ 0.420
Common stock prices - High	$ 61.13	$ 63.53	$ 64.58	$ 62.83
Common stock prices - Low	$ 44.65	$ 56.16	$ 56.86	$ 54.76

Income from continuing operations for each quarter of 2016 included external incremental acquisition and transaction costs. We incurred after-tax external incremental acquisition and transaction expenses of $15 million during the first quarter, $4.1 million during the second quarter, $4.1 million during the third quarter and $5.5 million during the fourth quarter.

Included with loss from discontinued operations in each quarter of 2016 are non-cash impairments of oil and gas properties. We recorded after-tax impairments of oil and gas properties of $8.8 million during the first quarter, $16 million during the second quarter, $7.9 million during the third quarter and $34 million during the fourth quarter.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)) as of December 31, 2017. Based on their evaluation, they have concluded that our disclosure controls and procedures are effective.

Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Security Exchange Act of 1934, as amended, is recorded, processed, summarized and reported, within the time periods specified in the Commission's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2017, there were no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting is presented on Page 88 of this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required under this item with respect to directors and information required by Items 401, 405, 406, 407(c)(3), 407(d)(4) and 407(d)(5) of Regulation S-K, is set forth in the Proxy Statement for our 2018 Annual Meeting of Shareholders, which is incorporated herein by reference.

Executive Officers

David R. Emery, age 55, has been Chairman and Chief Executive Officer since January 2016 and Chairman, President and Chief Executive Officer from 2005 through 2015. Prior to that, he held various positions with the Company, including President and Chief Executive Officer and member of the Board of Directors from 2004 to 2005, President and Chief Operating Officer — Retail Business Segment from 2003 to 2004 and Vice President — Fuel Resources from 1997 to 2003. Mr. Emery has 28 years of experience with the Company.

Scott A. Buchholz, age 56, has been our Senior Vice President — Chief Information Officer since the closing of the Aquila Transaction in 2008. Prior to joining the Company, he was Aquila's Vice President of Information Technology from 2005 until 2008, Six Sigma Deployment Leader/Black Belt from 2004 until 2005, and General Manager, Corporate Information Technology from 2002 until 2004. Mr. Buchholz has 37 years of experience with the Company, including 28 years with Aquila.

Linden R. Evans, age 55, has been President and Chief Operating Officer of the Company since January 2016 and President and Chief Operating Officer — Utilities from 2004 through 2015. Mr. Evans served as the Vice President and General Manager of our former communication subsidiary in 2003 and 2004, and served as our Associate Counsel from 2001 to 2003. Mr. Evans has 16 years of experience with the Company.

Brian G. Iverson, age 55, has been Senior Vice President, General Counsel and Chief Compliance Officer since April 2016. He served as Senior Vice President - Regulatory and Governmental Affairs and Assistant General Counsel from 2014 to April 2016, Vice President and Treasurer from 2011 to 2014, Vice President - Electric Regulatory Services from 2008 to 2011 and as Corporate Counsel from 2004 to 2008. Mr. Iverson has 14 years of experience with the Company.

Richard W. Kinzley, age 52, has been Senior Vice President and Chief Financial Officer since January 2015. He served as Vice President - Corporate Controller from 2013 to 2014, Vice President - Strategic Planning and Development from 2008 to 2013, and as Director of Corporate Development from 2000 to 2008. Mr. Kinzley has 18 years of experience with the Company.

Jennifer C. Landis, age 43, has been Senior Vice President - Chief Human Resources Officer since February 1, 2017. She served as Vice President of Human Resources from April 2016 through January 2017, Director of Corporate Human Resources and Talent Management from 2013 to April 2016, and Director of Organization Development from 2008 to 2013. Ms. Landis has 16 years of experience with the Company.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is set forth in the Proxy Statement for our 2018 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information regarding the security ownership of certain beneficial owners and management is set forth in the Proxy Statement for our 2018 Annual Meeting of Shareholders, which is incorporated herein by reference.

EQUITY COMPENSATION PLAN INFORMATION

The following table includes information as of December 31, 2017 with respect to our equity compensation plans. These plans include the 2005 Omnibus Incentive Plan and 2015 Omnibus Incentive Plan.

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	240,190 (1)	$ 44.83 (1)	979,464 (2)
Equity compensation plans not approved by security holders	—	$ —	—
Total	240,190	$ 44.83	979,464

(1) Includes 143,441 full value awards outstanding as of December 31, 2017, comprised of restricted stock units, performance shares, short-term incentive plan (STIP) units and Director common stock units. The weighted average exercise price does not include the restricted stock units, performance shares, STIP or common stock units. In addition, 267,284 shares of unvested restricted stock were outstanding as of December 31, 2017, which are not included in the above table because they have already been issued.

(2) Shares available for issuance are from the 2015 Omnibus Incentive Plan. The 2015 Omnibus Incentive Plan permits the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock based awards.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information regarding certain relationships and related transactions and director independence is set forth in the Proxy Statement for our 2018 Annual Meeting of Shareholders, which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information regarding principal accounting fees and services is set forth in the Proxy Statement for our 2018 Annual Meeting to Shareholders, which is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Consolidated Financial Statements

Financial statements required under this item are included in Item 8 of Part II

2. Schedules

Schedule II — Consolidated Valuation and Qualifying Accounts for the years ended December 31, 2017, 2016 and 2015

3. Exhibits

All other schedules have been omitted because of the absence of the conditions under which they are required or because the required information is included in our consolidated financial statements and notes thereto.

SCHEDULE II

BLACK HILLS CORPORATION
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2017, 2016 AND 2015

Description	Balance at Beginning of Year	Adjustments [a]	Additions Charged to Costs and Expenses	Recoveries and Other Additions	Write-offs and Other Deductions	Balance at End of Year
			(in thousands)			
Allowance for doubtful accounts:						
2017	$ 2,392	$ —	$ 4,926	$ 8,262	$ (12,499)	$ 3,081
2016	$ 1,741	$ 2,158	$ 2,704	$ 4,915	$ (9,126)	$ 2,392
2015	$ 1,516	$ —	$ 3,860	$ 4,132	$ (7,767)	$ 1,741

(a) Represents allowance balances added with the SourceGas acquisition.

3. Exhibits

Exhibit Number	Description
2.1*	Purchase and Sale Agreement by and among Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer, dated as of July 12, 2015 (filed as Exhibit 2.1 to the Registrant's Form 8-K filed on July 14, 2015).
2.2*	First Amendment to Purchase and Sale Agreement effective December 10, 2015, by and among, Alinda Gas Delaware LLC, Alinda Infrastructure Fund I, L.P. and Aircraft Services Corporation, as Sellers, and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 10-K for 2015).
2.3*	Option Agreement, by and among, Aircraft Services Corporation, as ASC, SourceGas Holdings LLC, as the Company and Black Hills Utility Holdings, Inc., as Buyer (filed as Exhibit 2.2 to the Registrant's Form 8-K filed on July 14, 2015).
3.1*	Restated Articles of Incorporation of the Registrant (filed as Exhibit 3 to the Registrant's Form 8-K filed on February 5, 2018).
3.2*	Amended and Restated Bylaws of the Registrant dated April 24, 2017 (filed as Exhibit 3 to the Registrant's Form 8-K filed on April 28, 2017).
4.1*	Indenture dated as of May 21, 2003 between the Registrant and Wells Fargo Bank, National Association (as successor to LaSalle Bank National Association), as Trustee (filed as Exhibit 4.1 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). First Supplemental Indenture dated as of May 21, 2003 (filed as Exhibit 4.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2003). Second Supplemental Indenture dated as of May 14, 2009 (filed as Exhibit 4 to the Registrant's Form 8-K filed on May 14, 2009). Third Supplemental Indenture dated as of July 16, 2010 (filed as Exhibit 4 to Registrant's Form 8-K filed on July 15, 2010). Fourth Supplemental Indenture dated as of November 19, 2013 (filed as Exhibit 4 to the Registrant's Form 8-K filed on November 18, 2013). Fifth Supplemental Indenture dated as of January 13, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on January 13, 2016). Sixth Supplemental Indenture dated as of August 19, 2016 (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on August 19, 2016).
4.2*	Restated and Amended Indenture of Mortgage and Deed of Trust of Black Hills Corporation (now called Black Hills Power, Inc.) dated as of September 1, 1999 (filed as Exhibit 4.19 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). First Supplemental Indenture, dated as of August 13, 2002, between Black Hills Power, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank), as Trustee (filed as Exhibit 4.20 to the Registrant's Post-Effective Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). Second Supplemental Indenture, dated as of October 27, 2009, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 4.21 to the Registrant's Post-Effective Amendment No. 2 to the Registrant's Registration Statement on Form S-3 (No. 333-150669)). Third Supplemental Indenture, dated as of October 1, 2014, between Black Hills Power, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on October 2, 2014).
4.3*	Restated Indenture of Mortgage, Deed of Trust, Security Agreement and Financing Statement, amended and restated as of November 20, 2007, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on October 2, 2014). First Supplemental Indenture, dated as of September 3, 2009, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on October 2, 2014). Second Supplemental Indenture, dated as of October 1, 2014, between Cheyenne Light, Fuel and Power Company and Wells Fargo Bank, National Association (filed as Exhibit 10.4 to the Registrant's Form 8-K filed on October 2, 2014).
4.4*	Junior Subordinated Indenture dated as of November 23, 2015 between Black Hills Corporation and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Registrant's Form 8-K filed on November 23, 2015). First Supplemental Indenture dated as of November 23, 2015 (filed as Exhibit 4.2 to the Registrant's Form 8-K filed on November 23, 2015).

4.5*	Purchase Contract and Pledge Agreement dated as of November 23, 2015 between Black Hills Corporation and U.S. Bank National Association, as purchase contract agent, collateral agent, custodial agent and securities intermediary (filed as Exhibit 4.4 to the Registrant's Form 8-K filed on November 23, 2015).
4.6*	Form of Stock Certificate for Common Stock, Par Value $1.00 Per Share (filed as Exhibit 4.2 to the Registrant's Form 10-K for 2000).
10.1*†	Amended and Restated Pension Equalization Plan of Black Hills Corporation dated November 6, 2001 (filed as Exhibit 10.11 to the Registrant's Form 10-K/A for 2001). First Amendment to Pension Equalization Plan (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2002). Grandfather Amendment to the Amended and Restated Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.2 to the Registrant's Form 10-K for 2008).
10.2*†	2005 Pension Equalization Plan of Black Hills Corporation (filed as Exhibit 10.3 to the Registrant's Form 10-K for 2008).
10.3*†	Restoration Plan of Black Hills Corporation (filed as Exhibit 10.5 to the Registrant's Form 10-K for 2008). First Amendment to the Restoration Plan of Black Hills Corporation dated July 24, 2011 (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarterly period ended June 30, 2011).
10.4*†	Black Hills Corporation Non-qualified Deferred Compensation Plan as Amended and Restated effective January 1, 2011 (filed as Exhibit 10.4 to the Registrant's Form 10-K for 2010).
10.5*†	Black Hills Corporation 2005 Omnibus Incentive Plan ("Omnibus Plan") (filed as Appendix A to the Registrant's Proxy Statement filed April 13, 2005). First Amendment to the Omnibus Plan (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2008). Second Amendment to the Omnibus Plan (filed as Exhibit 10 to the Registrant's Form 8-K filed on May 26, 2010).
10.6*†	Black Hills Corporation 2015 Omnibus Incentive Plan (filed as Appendix B to the Registrant's Proxy Statement filed March 19, 2015).
10.7*†	Form of Stock Option Agreement for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.7 to the Registrant's Form 10-K for 2013). Form of Stock Option Agreement effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.8 to Registrant's Form 10-K for 2015).
10.8*†	Form of Restricted Stock Award for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.9 to the Registrant's Form 10-K for 2013). Form of Restricted Stock Award Agreement effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.10 to Registrant's Form 10-K for 2015).
10.9*†	Form of Restricted Stock Unit Award Agreement for Omnibus Plan effective for awards granted on or after January 1, 2014 (filed as Exhibit 10.10 to the Registrant's Form 10-K for 2013). Form of Restricted Stock Unit Award Agreement for 2015 Omnibus Plan effective for awards granted on or after April 28, 2015 (filed as Exhibit 10.12 to the Registrant's Form 10-K for 2015).
10.10*†	Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2015 (filed as Exhibit 10.11 to the Registrant's Form 10-K for 2014). Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2016 (filed as Exhibit 10.6 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016). Form of Performance Share Award Agreement effective for awards granted on or after January 1, 2017.
10.11*†	Form of Short-term Incentive effective for awards granted on or after January 1, 2016 (filed as Exhibit 10.7 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016).
10.12*†	Form of Indemnification Agreement (filed as Exhibit 10.5 to the Registrant's Form 8-K filed on September 3, 2004).

10.13*†	Change in Control Agreement dated November 15, 2016 between Black Hills Corporation and David R. Emery (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on November 16, 2016).

10.14*†	Form of Change in Control Agreements between Black Hills Corporation and its non-CEO Senior Executive Officers (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on November 16, 2016).
10.15*†	Outside Directors Stock Based Compensation Plan as Amended and Restated effective January 1, 2009 (filed as Exhibit 10.23 to the Registrant's Form 10-K for 2008). First Amendment to the Outside Directors Stock Based Compensation Plan effective January 1, 2011 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2010). Second Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2013 (filed as Exhibit 10.15 to the Registrant's Form 10-K for 2012). Third Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2015 (filed as Exhibit 10.16 to the Registrant's Form 10-K for 2014). Fourth Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2017 (filed as Exhibit 10.4 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2016).
10.16†	Fifth Amendment to the Outside Director's Stock Based Compensation Plan effective January 1, 2018.
10.17*†	Form of Non-Disclosure and Non-Solicitation Agreement for Certain Employees (filed as Exhibit 10.8 to the Registrant's Form 10-Q for the quarterly period ended March 31, 2016).
10.18*	Equity Distribution Sales Agreement dated March 18, 2016 among Black Hills Corporation and the several Agents named therein (filed as Exhibit 1.1 to the Registrant's Form 8-K filed on March 18, 2016).
10.19*	Equity Distribution Sales Agreement dated August 4, 2017 among Black Hills Corporation and the several Agents named therein (filed as Exhibit 1.1 to the Registrant's Form 8-K filed on August 4, 2017).
10.20*	Bond Purchase Agreement dated as of June 30, 2014 by and among Black Hills Power, Inc., New York Life Insurance Company, New York Life Insurance and Annuity Corporation, Teachers Insurance and Annuity Association of America, John Hancock Life Insurance Company (U.S.A.), John Hancock Life & Health Insurance Company, John Hancock Life Insurance Company of New York and United of Omaha Life Insurance Company (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on July 2, 2014).
10.21*	Bond Purchase Agreement dated as of June 30, 2014 by and among Cheyenne Light Fuel and Power Company, New York Life Insurance Company, New York Life Insurance and Annuity Corporation, Teachers Insurance and Annuity Association of America, John Hancock Life Insurance Company (U.S.A.), John Hancock Life & Health Insurance Company, John Hancock Life Insurance Company of New York, Mutual of Omaha Insurance Company, United of Omaha Life Insurance Company and American Equity Investment Life Insurance Company (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on July 2, 2014).
10.22*	Third Amended and Restated Term Loan Credit Agreement, dated August 9, 2016 (relating to $340 million SourceGas Acquisition Credit Agreement - $0 balance at 12/31/2016) among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and J.P. Morgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.3 to the Registrant's Form 8-K filed on August 10, 2016).
10.23*	Second Amended and Restated Credit Agreement, dated August 9, 2016 (relating to $750 million Revolving Credit Facility), among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and U.S. Bank, National Association, as Administrative Agent (filed as Exhibit 10.1 to the Registrant's Form 8-K filed on August 10, 2016). Amendment No. 1 to Second Amended and Restated Credit Agreement dated as of December 7, 2016 (filed as Exhibit 10.22 to the Registrant's Form 10-K for 2016).
10.24*	Credit Agreement dated August 9, 2016 (relating to $500 million, three-year term loan - $300 million balance at 12/31/2017), among Black Hills Corporation, as Borrower, the financial institutions party thereto, as Banks, and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.2 to the Registrant's Form 8-K filed on August 10, 2016). Amendment No. 1 to Credit Agreement dated as of December 7, 2016 (filed as Exhibit 10.25 to the Registrant's Form 10-K for 2016).
10.25*	Coal Leases between WRDC and the Federal Government -Dated May 1, 1959 (filed as Exhibit 5(i) to the Registrant's Form S-7, File No. 2-60755)

-Modified January 22, 1990 (filed as Exhibit 10(h) to the Registrant's Form 10-K for 1989)
-Dated April 1, 1961 (filed as Exhibit 5(j) to the Registrant's Form S-7, File No. 2-60755)
-Modified January 22, 1990 (filed as Exhibit 10(i) to Registrant's Form 10-K for 1989)
-Dated October 1, 1965 (filed as Exhibit 5(k) to the Registrant's Form S-7, File No. 2-60755)
-Modified January 22, 1990 (filed as Exhibit 10(j) to the Registrant's Form 10-K for 1989).

10.26*	Assignment of Mining Leases and Related Agreement effective May 27, 1997, between WRDC and Kerr-McGee Coal Corporation (filed as Exhibit 10(u) to the Registrant's Form 10-K for 1997).
21	List of Subsidiaries of Black Hills Corporation.
23.1	Consent of Independent Registered Public Accounting Firm.
23.2	Consent of Petroleum Engineer and Geologist.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a - 14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes - Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	Mine Safety and Health Administration Safety Data
101	Financial Statements in XBRL Format

* Previously filed as part of the filing indicated and incorporated by reference herein.
† Indicates a board of director or management compensatory plan.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BLACK HILLS CORPORATION

By: /S/ DAVID R. EMERY
David R. Emery, Chairman and Chief Executive Officer

Dated: February 23, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

/S/ DAVID R. EMERY David R. Emery, Chairman and Chief Executive Officer	Director and Principal Executive Officer	February 23, 2018
/S/ RICHARD W. KINZLEY Richard W. Kinzley, Senior Vice President and Chief Financial Officer	Principal Financial and Accounting Officer	February 23, 2018
/S/ MICHAEL H. MADISON Michael H. Madison	Director	February 23, 2018
/S/ LINDA K. MASSMAN Linda K. Massman	Director	February 23, 2018
/S/ STEVEN R. MILLS Steven R. Mills	Director	February 23, 2018
/S/ ROBERT P. OTTO Robert P. Otto	Director	February 23, 2018
/S/ REBECCA B. ROBERTS Rebecca B. Roberts	Director	February 23, 2018
/S/ MARK A. SCHOBER Mark A. Schober	Director	February 23, 2018
/S/ TERESA A. TAYLOR Teresa A. Taylor	Director	February 23, 2018
/S/ JOHN B. VERING John B. Vering	Director	February 23, 2018
/S/ THOMAS J. ZELLER	Director	February 23, 2018

Thomas J. Zeller

PNM RESOURCES NYSE-PNM

RECENT PRICE **39.10** | P/E RATIO **22.3** (Trailing: 20.3 Median: 18.0) | RELATIVE P/E RATIO **1.19** | DIV'D YLD **2.8%** | **VALUE LINE**

TIMELINESS **3** Lowered 3/30/18
SAFETY **3** Lowered 5/9/08
TECHNICAL **5** Lowered 4/20/18
BETA .70 (1.00 = Market)

2021-23 PROJECTIONS

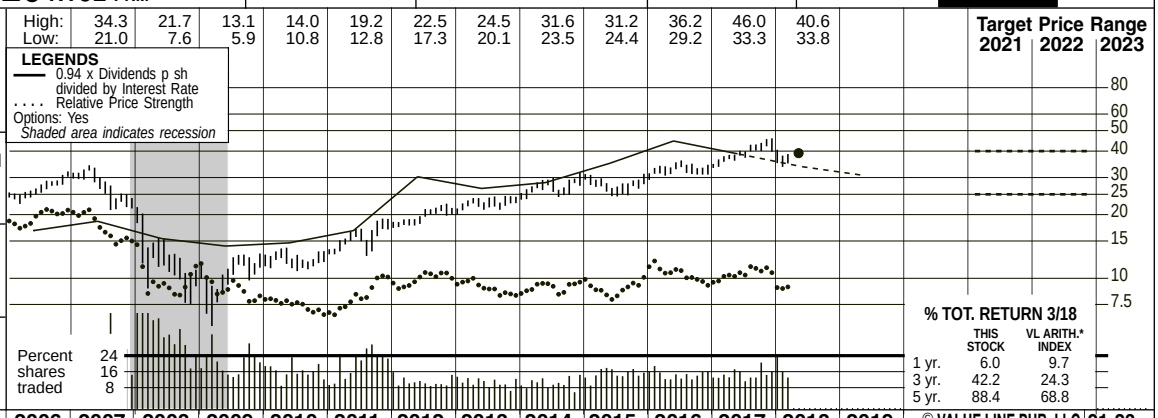
	Price	Gain	Ann'l Total Return
High	40	(Nil)	4%
Low	25	(-35%)	-6%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	1	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	0	0	2	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	124	119	133
to Sell	95	103	88
Hld's(000)	83799	82421	74432



2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
19.92	24.11	26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	18.07	17.11	18.14	*19.15*	*20.10*	Revenues per sh	*21.75*
2.83	3.05	3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.39	3.52	4.09	4.28	4.51	5.30	*5.55*	*6.15*	"Cash Flow" per sh	*7.25*
1.07	1.15	1.43	1.56	1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.45	1.48	1.46	1.92	*1.85*	*2.10*	Earnings per sh A	*2.50*
.57	.61	.63	.79	.86	.91	.61	.50	.50	.50	.58	.68	.76	.82	.90	.99	*1.08*	*1.14*	Div'd Decl'd per sh B ■ †	*1.35*
4.09	2.78	2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	7.01	7.53	6.28	*6.30*	*6.60*	Cap'l Spending per sh	*8.25*
16.60	17.84	18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	22.39	20.78	21.04	21.28	*21.90*	*21.90*	Book Value per sh C	*27.00*
58.68	60.39	60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	79.65	79.65	79.65	*79.65*	*79.65*	Common Shs Outst'g D	*79.65*
15.1	14.7	15.0	17.4	15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.7	18.7	22.4	20.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.5*
.82	.84	.79	.93	.84	1.89	NMF	1.21	.89	.91	.95	.90	.98	.94	1.18	1.03			Relative P/E Ratio	*.75*
3.5%	3.6%	2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.8%	3.0%	2.8%	2.5%			Avg Ann'l Div'd Yield	*4.0%*
1959.5	1647.7	1673.5	1700.6	1342.4	1387.9	1435.9	1439.1	1363.0	1445.0	*1525*	*1600*	Revenues ($mill)	*1800*
8.1	54.0	80.5	97.1	106.1	114.0	116.8	118.8	117.4	154.4	*160*	*185*	Net Profit ($mill)	*225*
40.4%	30.4%	32.6%	38.8%	31.4%	31.6%	34.8%	36.9%	32.4%	33.0%	*23.5%*	*28.0%*	Income Tax Rate	*28.0%*
- -	6.3%	7.1%	8.7%	7.1%	1.3%	10.7%	17.0%	11.0%	11.9%	*11.0%*	*11.0%*	AFUDC % to Net Profit	*11.0%*
45.6%	48.7%	50.4%	51.5%	50.9%	50.0%	47.8%	54.1%	55.7%	56.1%	*54.5%*	*56.0%*	Long-Term Debt Ratio	*54.0%*
54.0%	51.0%	49.2%	48.1%	48.7%	49.7%	51.9%	45.5%	44.0%	43.6%	*45.0%*	*44.0%*	Common Equity Ratio	*45.5%*
3025.4	3214.9	3100.3	3245.6	3277.9	3344.0	3437.1	3633.3	3806.8	3887.5	*3865*	*4135*	Total Capital ($mill)	*4900*
3192.0	3332.4	3444.4	3627.1	3746.5	3933.9	4270.0	4535.4	4904.7	4980.2	*5185*	*5390*	Net Plant ($mill)	*5975*
1.9%	3.2%	4.2%	4.5%	5.1%	5.2%	5.1%	4.8%	4.7%	5.3%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
.5%	3.3%	5.2%	6.2%	6.6%	6.8%	6.5%	7.1%	7.0%	9.0%	*8.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
.5%	3.3%	5.2%	6.2%	6.6%	6.8%	6.5%	7.1%	7.0%	9.1%	*8.5%*	*9.5%*	Return on Com Equity E	*9.5%*
NMF	.5%	2.2%	3.3%	3.8%	3.8%	3.2%	3.3%	2.8%	4.5%	*3.5%*	*4.5%*	Retained to Com Eq	*4.5%*
NMF	86%	57%	47%	43%	45%	51%	54%	61%	51%	*53%*	*49%*	All Div'ds to Net Prof	*50%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $2743.0 mill. **Due in 5 Yrs** $1440.8 mill.
LT Debt $2180.8 mill. **LT Interest** $113.0 mill.
(LT interest earned: 3.2x)
Leases, Uncapitalized Annual rentals $26.8 mill.
Pension Assets-12/17 $625.5 mill.
Oblig $692.4 mill.
Pfd Stock $11.5 mill. **Pfd Div'd** $.5 mill.
115,293 shs. 4.58%, $100 par without mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs.
as of 2/20/18
MARKET CAP: $3.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-1.4	-.5	+.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	2787	2791	2580
Peak Load, Summer (Mw)	1889	1908	1843
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+.9	+.8
Fixed Charge Cov. (%)	231	202	243

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-5.0%	-1.5%	*3.5%*
"Cash Flow"	4.0%	9.0%	*7.5%*
Earnings	2.0%	8.5%	*7.5%*
Dividends	.5%	11.5%	*7.0%*
Book Value	- -	2.0%	*4.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	332.9	352.9	417.4	335.9	1439.1
2016	311.0	315.4	400.4	336.2	1363.0
2017	330.2	362.3	419.9	332.6	1445.0
2018	*345*	*370*	*440*	*370*	*1525*
2019	*360*	*390*	*460*	*390*	*1600*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.18	.40	.76	.14	1.48
2016	.13	.34	.68	.31	1.46
2017	.29	.47	.92	.25	1.92
2018	*.27*	*.43*	*.80*	*.35*	*1.85*
2019	*.30*	*.50*	*.90*	*.40*	*2.10*

QUARTERLY DIVIDENDS PAID B ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.185	.185	.185	.185	.74
2015	.20	.20	.20	.20	.80
2016	.22	.22	.22	.22	.88
2017	.2425	.2425	.2425	.2425	.97
2018	.265				

BUSINESS: PNM Resources, Inc. is a holding company with two regulated electric utilities. Public Service Company of New Mexico (PNM) serves 524,000 customers in north central New Mexico, incl. Albuquerque and Santa Fe. Texas-New Mexico Power Company (TNMP) transmits and distributes power to 250,000 customers in Texas. Electric rev. breakdown: residential, 39%; commercial, 37%; industrial, 5%; other, 19%. Generating sources: coal, 57%; nuclear, 30%; gas/oil, 12%; solar, 1%. Fuel costs: 28% of revenues. '17 reported deprec. rates: 2.5%-8.4%. Has 1,700 employees. Chairman, President & CEO: Patricia K. Collawn. Inc.: New Mexico. Address: 414 Silver Ave. SW, Albuquerque, NM 87102-3289. Tel.: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources' earnings will probably decline in 2018. In late 2017, Public Service Company of New Mexico received a rate increase that will be phased in over a two-year period beginning this year. Because the utility isn't getting the entire raise right away, but higher expenses are already in effect, this will hurt the bottom line this year. PNM raised its earnings guidance from $1.70-$1.80 to $1.77-$1.87 to reflect the effects of tax reform. We boosted our estimate by $0.15 a share, to $1.85. Note that a regulatory disallowance in the rate case forced the company to take a $27 million pretax charge against fourth-quarter results, which we *excluded* from our earnings presentation as a nonrecurring item. We also excluded a $57.5 million charge associated with the remeasurement of deferred taxes following the new federal tax law.

Earnings should advance strongly in 2019. P.S. of New Mexico will receive the second phase of the aforementioned tariff hike. In addition, Texas-New Mexico Power Company plans to file a rate application in Texas next month. An order is expected in December, with new rates taking effect in January. Our 2019 profit forecast is at the midpoint of the company's targeted range of $2.04-$2.16 a share.

Dividend hikes have been strong over the past several years, but the growth rate is decelerating. Since 2012, this rate has been in a low double-digit range, on average. However, the company expects future dividend increases to mirror its long-term earnings growth rate, at approximately 6%. This pace is still slightly above the mean for the electric utility industry.

We believe more-attractive selections are available elsewhere. The company is facing some challenges. P.S. of New Mexico isn't seeing any load growth (on a weather-normalized basis). The regulatory climate in the state is difficult. (In fact, the utility's appeal of the rate order it received in 2015 is still pending before the New Mexico Supreme Court.) The dividend yield is below average for a utility. Total return potential over the 3- to 5-year period is low, given that the recent quotation is near the upper end of our 2021-2023 Target Price Range.

Paul E. Debbas, CFA *April 27, 2018*

(A) Dil. EPS. Excl. nonrec. gains (losses): '03, 67¢; '05, (56¢); '08, ($3.77); '10, ($1.36); '11, 88¢; '13, (16¢); '15, ($1.28); '17, (92¢). Excl. gains from disc. ops.: '08, 42¢; '09, 78¢. '15 & '17 EPS don't sum due to rounding. Next egs. report due late July. **(B)** Div'ds paid mid-Feb., May, Aug., & Nov. ■ Div'd reinvest. plan avail. † Shrhldr. invest. plan avail. **(C)** Incl. intang. In '17: $12.19/sh. **(D)** In mill., adj. for split. **(E)** Rate base: net orig. cost. Rate all'd on com. eq. in '18: 9.575%; earn. on avg. com. eq., '17: 8.9%. Reg. Climate: NM, Below Avg.; TX, Avg.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	95
Earnings Predictability	70

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Section 1: 10-K (PNM 2017 10-K)

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2017

Commission File Number	Names of Registrants, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
001-32462	PNM Resources, Inc. (A New Mexico Corporation) 414 Silver Ave. SW Albuquerque, New Mexico 87102-3289 (505) 241-2700	85-0468296
001-06986	Public Service Company of New Mexico (A New Mexico Corporation) 414 Silver Ave. SW Albuquerque, New Mexico 87102-3289 (505) 241-2700	85-0019030
002-97230	Texas-New Mexico Power Company (A Texas Corporation) 577 N. Garden Ridge Blvd. Lewisville, Texas 75067 (972) 420-4189	75-0204070

Securities Registered Pursuant To Section 12(b) Of The Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
PNM Resources, Inc.	Common Stock, no par value	New York Stock Exchange

Securities Registered Pursuant To Section 12(g) Of The Act:

Registrant	Title of Each Class
Public Service Company of New Mexico	1965 Series, 4.58% Cumulative Preferred Stock ($100 stated value without sinking fund)

Indicate by check mark whether each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

PNM Resources, Inc. (“PNMR”)	YES ü	NO _
Public Service Company of New Mexico (“PNM”)	YES _	NO ü
Texas-New Mexico Power Company (“TNMP”)	YES _	NO ü

Indicate by check mark if each registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

PNMR	YES _	NO ü
PNM	YES _	NO ü
TNMP	YES ü	NO _

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Indicate by check mark whether each registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

PNMR	YES ü	NO _
PNM	YES ü	NO _
TNMP	YES _	NO ü

(NOTE: As a voluntary filer, not subject to the filing requirements, TNMP filed all reports under Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months.)

Indicate by check mark whether each registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to

Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

PNMR	YES ü	NO _
PNM	YES ü	NO _
TNMP	YES ü	NO _

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S–K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. _

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

	Large accelerated filer	Accelerated filer	Non-accelerated filer (Do not check if a smaller reporting company)	Smaller reporting company	Emerging growth company
PNMR	ü	_	_	_	_
PNM	_	_	ü	_	_
TNMP	_	_	ü	_	_

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. £

Indicate by check mark whether the registrants are a shell company (as defined in Rule 12b-2 of the Exchange Act). YES _ NO ü

As of February 20, 2018, shares of common stock outstanding were:

PNMR	79,653,624
PNM	39,117,799
TNMP	6,358

On June 30, 2017, the aggregate market value of the voting common stock held by non-affiliates of PNMR as computed by reference to the New York Stock Exchange composite transaction closing price of $38.25 per share reported by The Wall Street Journal, was $3,046,751,118. PNM and TNMP have no common stock held by non-affiliates.

PNM AND TNMP MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTIONS (I) (1) (a) AND (b) OF FORM 10-K AND ARE THEREFORE FILING THIS FORM WITH THE REDUCED DISCLOSURE FORMAT PURSUANT TO GENERAL INSTRUCTION (I) (2).

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the following document are incorporated by reference into Part III of this report:

Proxy Statement to be filed by PNMR with the SEC pursuant to Regulation 14A relating to the annual meeting of stockholders of PNMR to be held on May 22, 2018.

This combined Form 10-K is separately filed by PNMR, PNM, and TNMP. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other registrants. When this Form 10-K is incorporated by reference into any filing with the SEC made by PNMR, PNM, or TNMP, as a registrant, the portions of this Form 10-K that relate to each other registrant are not incorporated by reference therein.

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PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES
TEXAS-NEW MEXICO POWER COMPANY AND SUBSIDIARIES

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S&P Global Market Intelligence

GLOSSARY

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2017 IRP	PNM's 2017 IRP
ABCWUA	Albuquerque Bernalillo County Water Utility Authority
ABO	Accumulated Benefit Obligation
AEP OnSite Partners	AEP OnSite Partners, LLC, a subsidiary of American Electric Power, Inc.
Afton	Afton Generating Station
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
AMS	Advanced Meter System
Anaheim	City of Anaheim, California
AOCI	Accumulated Other Comprehensive Income
APBO	Accumulated Postretirement Benefit Obligation
APS	Arizona Public Service Company, the operator and a co-owner of PVNGS and Four Corners
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
August RD	Recommended Decision in PNM's NM 2015 Rate Case issued by the Hearing Examiner on August 4, 2016
BART	Best Available Retrofit Technology
BDT	Balanced Draft Technology
BHP	BHP Billiton, Ltd
Board	Board of Directors of PNMR
BTMU	The Bank of Tokyo-Mitsubishi UFJ, Ltd.
BTMU Term Loan Agreement	NM Capital's $125.0 Million Unsecured Term Loan
BTU	British Thermal Unit
CAA	Clean Air Act
CCB	Coal Combustion Byproducts
CCN	Certificate of Convenience and Necessity
CIAC	Contributions in Aid of Construction
CO2	Carbon Dioxide
CSA	Coal Supply Agreement

CTC	Competition Transition Charge
DC Circuit	United States Court of Appeals for the District of Columbia Circuit
Delta	Delta-Person Generating Station, now known as Rio Bravo
DOE	United States Department of Energy
DOI	United States Department of Interior
EGU	Electric Generating Unit
EIP	Eastern Interconnection Project
EIS	Environmental Impact Study
EPA	United States Environmental Protection Agency
EPE	El Paso Electric Company
ERCOT	Electric Reliability Council of Texas
ESA	Endangered Species Act
Exchange Act	Securities Exchange Act of 1934
Farmington	The City of Farmington, New Mexico
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission

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FIP	Federal Implementation Plan
Four Corners	Four Corners Power Plant
FPL	FPL Energy New Mexico Wind, LLC
FPPAC	Fuel and Purchased Power Adjustment Clause
FTY	Future Test Year
GAAP	Generally Accepted Accounting Principles in the United States of America
GHG	Greenhouse Gas Emissions
GWh	Gigawatt hours
IBEW	International Brotherhood of Electrical Workers
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ISFSI	Independent Spent Fuel Storage Installation
KW	Kilowatt
KWh	Kilowatt Hour
La Luz	La Luz Generating Station
LIBOR	London Interbank Offered Rate
Lightning Dock Geothermal	Lightning Dock geothermal power facility, also known as the Dale Burgett Geothermal Plant
Lordsburg	Lordsburg Generating Station
Los Alamos	The Incorporated County of Los Alamos, New Mexico
Luna	Luna Energy Facility
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MMBTU	Million BTUs
Moody's	Moody's Investor Services, Inc.
MSR	M-S-R Public Power Agency
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standards
Navajo Acts	Navajo Nation Air Pollution Prevention and Control Act, Navajo Nation Safe Drinking Water Act, and Navajo Nation Pesticide Act
NDT	Nuclear Decommissioning Trusts for PVNGS
NEC	Navopache Electric Cooperative, Inc.
NEE	New Energy Economy
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
New Mexico Wind	New Mexico Wind Energy Center
NM 2015 Rate Case	Request for a General Increase in Electric Rates Filed by PNM on August 27, 2015
NM 2016 Rate Case	Request for a General Increase in Electric Rates Filed by PNM on December 7, 2016
NM Capital	NM Capital Utility Corporation, an unregulated wholly-owned subsidiary of PNMR
NM District Court	United States District Court for the District of New Mexico
NM Supreme Court	New Mexico Supreme Court
NMAG	New Mexico Attorney General
NMED	New Mexico Environment Department
NMIEC	New Mexico Industrial Energy Consumers Inc.
NMMMD	The Mining and Minerals Division of the New Mexico Energy, Minerals and Natural Resources Department
NMPRC	New Mexico Public Regulation Commission
NMRD	NM Renewable Development, LLC, owned 50% each by PNMR Development and AEP OnSite Partners, LLC

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NOx	Nitrogen Oxides
NOPR	Notice of Proposed Rulemaking

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NPDES	National Pollutant Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NSR	New Source Review
NTEC	Navajo Transitional Energy Company, LLC, an entity owned by the Navajo Nation
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OSM	United States Office of Surface Mining Reclamation and Enforcement
PBO	Projected Benefit Obligation
PCRBs	Pollution Control Revenue Bonds
PNM	Public Service Company of New Mexico and Subsidiaries
PNM 2014 New Mexico Credit Facility	PNM's $50.0 Million Unsecured Revolving Credit Facility
PNM 2014 Term Loan Agreement	PNM's $175.0 Million Unsecured Term Loan
PNM 2016 Term Loan Agreement	PNM's $175.0 Million Unsecured Term Loan
PNM 2017 New Mexico Credit Facility	PNM's $40.0 Million Unsecured Revolving Credit Facility
PNM 2017 Senior Unsecured Note Agreement	PNM's Agreement for the sale of Senior Unsecured Notes, aggregating $450.0 million
PNM 2017 Term Loan Agreement	PNM's $200.0 Million Unsecured Term Loan
PNM 2018 SUNs	PNM's Senior Unsecured Notes to be issued under the PNM 2017 Senior Unsecured Note Agreement
PNM Multi-draw Term Loan	PNM's $125.0 Million Unsecured Multi-draw Term Loan Facility
PNM Revolving Credit Facility	PNM's $400.0 Million Unsecured Revolving Credit Facility
PNMR	PNM Resources, Inc. and Subsidiaries
PNMR 2015 Term Loan Agreement	PNMR's $150.0 Million Three-Year Unsecured Term Loan
PNMR 2016 One-Year Term Loan	PNMR's $100.0 Million One-Year Unsecured Term Loan
PNMR 2016 Two-Year Term Loan	PNMR's $100.0 Million Two-Year Unsecured Term Loan
PNMR Development	PNMR Development and Management Company, an unregulated wholly-owned subsidiary of PNMR
PNMR Revolving Credit Facility	PNMR's $300.0 Million Unsecured Revolving Credit Facility
PNMR Term Loan Agreement	PNMR's $150.0 Million One-Year Unsecured Term Loan
PPA	Power Purchase Agreement
PSA	Power Sales Agreement
PSD	Prevention of Significant Deterioration
PUCT	Public Utility Commission of Texas
PV	Photovoltaic
PVNGS	Palo Verde Nuclear Generating Station
RA	Restructuring Agreement
RCRA	Resource Conservation and Recovery Act
RCT	Reasonable Cost Threshold
REA	New Mexico's Renewable Energy Act of 2004
REC	Renewable Energy Certificates

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Red Mesa Wind	Red Mesa Wind Energy Center
REP	Retail Electricity Provider
RFP	Request For Proposal
Rio Bravo	Rio Bravo Generating Station, formerly known as Delta
RMC	Risk Management Committee
ROE	Return on Equity
RPS	Renewable Energy Portfolio Standard
RSIP	Revised State Implementation Plan
S&P	Standard and Poor's Ratings Services
SCE	Southern California Edison Company
SCPPA	Southern California Public Power Authority
SCR	Selective Catalytic Reduction
SEC	United States Securities and Exchange Commission

SIP	State Implementation Plan
SJCC	San Juan Coal Company
SJGS	San Juan Generating Station
SJGS CSA	San Juan Generating Station Coal Supply Agreement
SJGS RA	San Juan Project Restructuring Agreement
SJPPA	San Juan Project Participation Agreement
SNCR	Selective Non-Catalytic Reduction
SO2	Sulfur Dioxide
SPS	Southwestern Public Service Company
SRP	Salt River Project
TCEQ	Texas Commission on Environmental Quality
TECA	Texas Electric Choice Act
Tenth Circuit	United States Court of Appeals for the Tenth Circuit
TNMP	Texas-New Mexico Power Company and Subsidiaries
TNMP 2015 Bond Purchase Agreement	TNMP's $60.0 Million First Mortgage Bonds
TNMP 2017 Bond Purchase Agreement	TNMP's Agreement for the issuance of $60.0 Million First Mortgage Bonds
TNMP Revolving Credit Facility	TNMP's $75.0 Million Secured Revolving Credit Facility
TNP	TNP Enterprises, Inc. and Subsidiaries
Tri-State	Tri-State Generation and Transmission Association, Inc.
Tucson	Tucson Electric Power Company
UAMPS	Utah Associated Municipal Power Systems
UG-CSA	Underground Coal Sales Agreement for San Juan Generating Station
US Supreme Court	United States Supreme Court
Valencia	Valencia Energy Facility
VaR	Value at Risk
VIE	Variable Interest Entity
WACC	Weighted Average Cost of Capital
WEG	WildEarth Guardians
Westmoreland	Westmoreland Coal Company
Westmoreland Loan	$125.0 Million of funding provided by NM Capital to WSJ
WSJ	Westmoreland San Juan, LLC, an indirect wholly-owned subsidiary of Westmoreland
WSPP	Western Systems Power Pool

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PART I

ITEM 1. BUSINESS

THE COMPANY

Overview

PNMR is an investor-owned holding company with two regulated utilities providing electricity and electric services in New Mexico and Texas. PNMR's electric utilities are PNM and TNMP. PNMR is focused on achieving the following strategic goals:

- Earning authorized returns on its regulated businesses
- Delivering above industry-average earnings and dividend growth
- Maintaining solid investment grade credit ratings

In conjunction with these goals, PNM and TNMP are dedicated to:

- Maintaining strong employee safety, plant performance, and system reliability
- Delivering a superior customer experience
- Demonstrating environmental stewardship in their business operations
- Supporting the communities in their service territories

PNMR's success in accomplishing these strategic goals is highly dependent on favorable regulatory treatment for its regulated utilities. Both PNM and TNMP seek cost recovery for their investments through general rate cases and various rate riders. PNM filed general rate cases with the NMPRC in August 2015 and December 2016. The NMPRC issued rate orders in those cases in September 2016 and January 2018. TNMP plans to file a general rate case in May 2018. Additional information about rate filings is provided in Operations and Regulation below and in Note 17.

PNMR's common stock trades on the New York Stock Exchange under the symbol PNM. PNMR was incorporated in the State of New Mexico in 2000.

Other Information

These filings for PNMR, PNM, and TNMP include disclosures for each entity. For discussion purposes, this report uses the term "Company" when discussing matters of common applicability to PNMR, PNM, and TNMP. Discussions regarding only PNMR, PNM, or TNMP are so indicated. A reference to "MD&A" in this report refers to Part II, Item 7. – Management's Discussion and Analysis of Financial Condition and Results of Operations. A reference to a "Note" refers to the accompanying Notes to Consolidated Financial Statements.

Financial information relating to amounts of revenue, net income, and total assets of reportable segments is contained in MD&A and Note 2.

WEBSITES

The PNMR website, www.pnmresources.com, is an important source of Company information. New or updated information for public access is routinely posted. PNMR encourages analysts, investors, and other interested parties to register on the website to automatically receive Company information by e-mail. This information includes news releases, notices of webcasts, and filings with the SEC. Participants will not receive information that was not requested and can unsubscribe at any time.

Our corporate internet addresses are:

- PNMR: www.pnmresources.com
- PNM: www.pnm.com
- TNMP: www.tnmp.com

The PNMR website includes a link to PNMR's Sustainability Portal, www.pnmresources.com/about-us/sustainability-portal.aspx. This portal provides access to key sustainability information, including a Climate Change Report, related to the operations of PNM and TNMP and reflects PNMR's commitment to do business in an ethical, open, and transparent manner.

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The contents of these websites are not a part of this Form 10-K. The SEC filings of PNMR, PNM, and TNMP, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, are accessible free of charge on the PNMR website as soon as reasonably practicable after they are filed with, or furnished to, the SEC. These documents may be read and copied at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Further information about the Public Reference Room can be obtained by calling the SEC at 1-800-SEC-0330. Reports filed with the SEC are available on its website, *www.sec.gov*. These reports are also available in print upon request from PNMR free of charge.

Also available on the Company's website at http://www.pnmresources.com/corporate-governance.aspx and in print upon request from any shareholder are PNMR's:

- Corporate Governance Principles
- Code of Ethics (*Do the Right Thing – Principles of Business Conduct*)
- Charters of the Audit and Ethics Committee, Nominating and Governance Committee, Compensation and Human Resources Committee, and Finance Committee
- Restated Articles of Incorporation and Bylaws

The Company will post amendments to or waivers from its code of ethics (to the extent applicable to the Company's executive officers and directors) on its website.

OPERATIONS AND REGULATION

Regulated Operations

PNM

PNM is an electric utility that provides electric generation, transmission, and distribution service to its rate-regulated customers. PNM was incorporated in the State of New Mexico in 1917. PNM's retail electric service territory covers a large area of north central New Mexico, including the cities of Albuquerque, Rio Rancho, and Santa Fe, and certain areas of southern New Mexico. Service to retail electric customers is subject to the jurisdiction of the NMPRC. The largest retail electric customer served by PNM accounted for 2.4% of its revenues for the year ended December 31, 2017. Other services provided by PNM include wholesale transmission services to third parties as well as the generation and sale of electricity into the wholesale market, which services are regulated by FERC. PNM owns transmission lines that are interconnected with other utilities in New Mexico, Texas, Arizona, Colorado, and Utah. Regulation encompasses the utility's electric rates, service, accounting, issuances of securities, construction of major new generation, abandonment of existing generation, types of generation resources, transmission and distribution facilities, and other matters. See Note 17 for additional information on rate cases and other regulatory matters.

NMPRC Regulated Retail Rate Proceedings

Customer rates for retail electric service are set by the NMPRC. On October 1, 2016, PNM implemented a NMPRC order in PNM's NM 2015 Rate Case that approved an increase in non-fuel base rates of $61.2 million annually. PNM is appealing certain aspects of the NMPRC's order in the NM Supreme Court. Other parties in that rate case have filed cross-appeals contesting other aspects of the NMPRC ruling. Oral argument at the NM Supreme Court was held on October 30, 2017. Although appeals of regulatory actions of the NMPRC have priority at the NM Supreme Court, there is no required time frame for the court to act on the appeal. See Note 17.

In December 2016, PNM filed a general rate case (the "NM 2016 Rate Case") with the NMPRC. The December 2016 application proposed a non-fuel revenue increase of $99.2 million above the October 1, 2016 rates to be effective on January 1, 2018. The requested increase was based on a calendar 2018 future test year ("FTY") and a ROE of 10.125% compared to a ROE of 9.575% authorized in the NM 2015 Rate Case. The primary drivers of PNM's identified revenue deficiency were the implementation of the plan for SJGS to comply with the CAA Note 16, including the shutdown of Units 2 and 3 of SJGS, recovery of 50% of the net book value of those units, and the inclusion in retail rates of PVNGS Unit 3 as replacement power. The increase also reflects new infrastructure investments and declines in forecasted energy sales resulting from PNM's successful energy efficiency programs and other economic factors. PNM also proposed changes to rate design to better align electric rates with the actual costs to serve customers and encourage continued energy efficiency while proposing a rate mechanism that eliminates the disincentives associated with energy efficiency and load management programs. In May 2017, PNM and several intervenors filed a stipulation that, subject to approval by the NMPRC, would reduce the requested non-fuel revenue increase to $62.3 million, with an initial increase of $32.3 million beginning January 1, 2018 and the remaining increase beginning January 1, 2019. Among

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other things, the revised stipulation proposed to reduce the ROE to 9.575% and to provide a debt-only return on PNM's investment in SCRs at Four Corners. Hearings on the revised stipulation were held in August 2017. On October 31, 2017, the Hearing Examiners to the NM 2016 Rate Case issued their Certification of Stipulation recommending approval of the agreed upon revised stipulation with certain modifications, including identifying PNM's continuation in Four Corners as imprudent and recommending against PNM's ability to collect a debt or equity return on certain investments in that facility. On December 20, 2017, the NMPRC issued an order partially adopting the Certification of Stipulation, which approved the requested non-fuel revenue increase of $62.3 million over two years, but including additional modifications to reflect the impact of federal tax reform in customer rates beginning in 2018, rather than

in 2019 as proposed in the revised stipulation, and deferring further consideration regarding PNM's prudence related to Four Corners to a future proceeding. On December 28, 2017, PNM filed a motion for rehearing asking the NMPRC to vacate the December 20, 2017 order and requesting oral argument. After rehearing, the NMPRC issued a new order partially adopting the Certification of Stipulation with certain modifications, which, after further clarification, allows PNM to collect a debt return, but not an equity return, on certain of PNM's investments in Four Corners; defers further consideration regarding the prudency of PNM's continued participation in Four Corners to PNM's next general rate case; requires PNM to reduce the $62.3 million annual non-fuel revenue increase by $4.4 million; requires the annual impacts of federal tax reform, estimated to amount to $47.6 million, to be reflected in customer rates beginning in 2018; and requires 50% of the rate increase be implemented for service rendered (rather than for bills rendered as PNM had requested) on or after February 1, 2018 and the rest of the increase for service rendered on or after January 1, 2019. The order results in an annual non-fuel revenue increase of $10.3 million. On February 7, 2018, NEE filed a notice of appeal with the NM Supreme Court asking the court to review the NMPRC's decisions in the NM 2016 Rate Case. The notice does not set forth the basis of the appeal, which, as required by the court's rules, is to be filed by March 9, 2018. See Note 17.

PNM has a NMPRC-approved rate rider to collect costs for renewable energy procurements that are not otherwise being collected in rates. If PNM's earned return on jurisdictional equity in a calendar year, adjusted for weather and other items not representative of normal operation, exceeds the NMPRC-approved rate by 0.5%, the rider provides that PNM would refund the excess to customers during the following year. Through 2017, PNM's earned return on jurisdictional equity has not exceeded the limitation. The NMPRC has also approved riders designed to allow PNM to bill and collect substantially all of fuel and purchased power costs and costs of approved energy efficiency initiatives.

FERC Regulated Wholesale Operations

Rates charged to wholesale electric transmission customers are based on a formula rate mechanism pursuant to which rates for wholesale transmission service are calculated annually in accordance with an approved formula. The formula includes updating cost of service components, including investment in plant and operating expenses, based on information contained in PNM's annual financial report filed with FERC, as well as including projected large transmission capital projects to be placed into service in the following year. The projections included are subject to true-up in the formula rate for the following year. Certain items, including changes to return on equity and depreciation rates, require a separate filing to be made with FERC before being included in the formula rate.

The low natural gas price environment has resulted in market prices for power being substantially lower that what PNM has been able to offer wholesale generation customers under the cost of service model that FERC requires PNM to use. Consequently, PNM requested FERC approval to enter into arrangements to sell electricity at wholesale prices within PNM's balance authority area using rates based on market conditions. In October 2015, FERC denied PNM's request. Accordingly, PNM has decided to stop pursuing wholesale generation contracts.

Operational Information

Weather-normalized retail electric KWh sales decreased by 0.9% in 2017 and 0.7% in 2016. The system peak demands for retail and firm-requirements customers were as follows:

System Peak Demands

	2017	2016	2015
		(Megawatts)	
Summer	1,843	1,908	1,889
Winter	1,289	1,376	1,433

PNM holds long-term, non-exclusive franchise agreements for its electric retail operations, with varying expiration dates. These franchise agreements allow the utility to access public rights-of-way for placement of its electric facilities. Franchise

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agreements have expired in some areas PNM serves, including Albuquerque, Rio Rancho, and Santa Fe. Because PNM remains obligated under New Mexico state law to provide service to customers in these areas, the expirations should not have a material adverse impact. The Albuquerque, Rio Rancho, and Santa Fe metropolitan areas accounted for 48.2%, 9.9%, and 9.5% of PNM's 2017 revenues and no other franchise area represents more than 5%. Although PNM is not required to collect or pay franchise fees in some areas it serves, the utility continues to collect and pay such fees in certain parts of its service territory, including Albuquerque, Rio Rancho, and Santa Fe.

As discussed in Note 16, the County Commission of Bernalillo County, New Mexico passed an ordinance in January 2014 that would require PNM and other utilities to enter into a use agreement and pay a yet-to-be-determined fee as a condition for installing, maintaining, and operating facilities on county rights-of-way. PNM and other utilities have filed complaints in federal and state courts challenging the validity of the ordinance. If the challenge to the ordinance is unsuccessful, PNM believes any fees paid pursuant to the ordinance would be considered franchise fees and would be recoverable from customers. PNM is unable to predict the outcome of this matter.

PNM owns 3,200 miles of electric transmission lines that interconnect with other utilities in New Mexico, Arizona, Colorado, Texas, and Utah. There has been little development of new bulk transmission facilities since 1985. PNM owns transmission capacity in an area of eastern New Mexico with large wind generation potential and in recent years there has been substantial interest by developers of wind generation to interconnect to PNM's transmission system in this area. PNM plans to construct approximately $170 million of new transmission facilities by 2020 to provide additional transmission service to deliver power from these generation resources to customers in New Mexico and California.

PNM also generates and sells electricity into the wholesale market. Through December 31, 2017, PNM's 134 MW share of Unit 3 at PVNGS was excluded from retail rates and was being sold in the wholesale market. In December 2015, the NMPRC approved PNM's request to include PVNGS Unit 3 as a jurisdictional resource to serve New Mexico retail customers beginning in 2018 and also authorized PNM to acquire 65 MW of SJGS Unit 4 as merchant plant. See Note 16 and Note 17. Shareholders realize any earnings or losses from generating resources that are not included in retail rates. In addition, PNM engages in activities to optimize its existing jurisdictional assets and long-term power agreements through spot market, hour-ahead, day-ahead, week-ahead, and other sales of any excess generation not required to fulfill retail load and contractual commitments. Through PNM's FPPAC, 90% of the margins from these optimization sales were credited to retail customers through December 31, 2016, after which date 100% of the margins are credited to customers.

Use of Future Test Year ("FTY")

Under New Mexico law, the NMPRC must set rates using the test period, including a FTY, that best reflects the conditions the utility will experience when new rates are anticipated to go into effect. In November 2015, the NMPRC clarified that FTY could begin up to 13 months after the filing of a rate case application. The NMPRC also must include certain construction work in progress for environmental improvement, generation, and transmission projects in rate base. These provisions are designed to promote more timely recovery of reasonable costs of providing utility service.

The use of a FTY should help PNM mitigate the adverse effects of regulatory lag, which is inherent when using a historical test year. Accordingly, the utility's earnings should more closely reflect the rate of return allowed by the NMPRC. PNMR believes that achieving earnings that approximate its allowed rate of return is an important factor in attracting equity investors, as well as being considered favorably by credit rating agencies and financial analysts.

As with any forward looking financial information, utilizing a FTY in a rate filing presents challenges. These include forecasts of both operating and capital expenditures that necessitate reliance on many assumptions concerning future conditions and operating results. In the rate making process, PNM's assumptions are subject to challenge by regulators and intervenors who may assert different interpretations or assumptions.

Renewable Energy

The REA was enacted to encourage the development of renewable energy in New Mexico. The act establishes a mandatory RPS requiring a utility to acquire a renewable energy portfolio equal to 10% of retail electric sales by 2011, 15% by 2015, and 20% by 2020. The act provides for streamlined proceedings for approval of utilities' renewable energy procurement plans, assures utilities recovery of costs incurred consistent with approved procurement plans, and requires the NMPRC to establish a RCT for the procurement of renewable resources to prevent excessive costs being added to rates. PNM files required renewable energy plans with the NMPRC annually and makes procurements consistent with the plans approved by the NMPRC. See Note 17.

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TNMP

TNMP is a regulated utility operating and incorporated in the State of Texas. TNMP's predecessor was organized in 1925. TNMP provides transmission and distribution services in Texas under the provisions of TECA and the Texas Public Utility Regulatory Act. TNMP is subject to traditional cost-of-service regulation with respect to rates and service under the jurisdiction of the PUCT and certain municipalities. TNMP's transmission and distribution activities are solely within ERCOT, which is the independent system operator responsible for maintaining reliable operations for the bulk electric power supply system in most of Texas. Therefore, TNMP is not subject to traditional rate regulation by FERC. TNMP serves a market of small to medium sized communities, most of which have populations of less than 50,000. TNMP is the exclusive provider of transmission and distribution services in most areas it serves.

TNMP's service territory consists of three non-contiguous areas. One portion of this territory extends from Lewisville, which is approximately 10 miles north of the Dallas-Fort Worth International Airport, eastward to municipalities near the Red River, and to communities north, west, and south of Fort Worth. The second portion of its service territory includes the area along the Texas Gulf Coast between Houston and Galveston, and the third portion includes areas of far west Texas between Midland and El Paso.

TNMP provides transmission and distribution services at regulated rates to various REPs that, in turn, provide retail electric service to consumers within TNMP's service area. TNMP experienced increases in weather-normalized retail KWh sales of 1.2% in 2017 and 3.0% in 2016. As of December 31, 2017, 101 active REPs receive transmission and distribution services from TNMP. In 2017, the three largest REP customers of TNMP accounted for operating revenues of 16%, 11%, and 10%. No other customer accounted for more than 10% of revenues.

Regulatory Activities

In July 2011, the PUCT approved a settlement and authorized an AMS deployment plan that permits TNMP to collect $113.4 million in deployment costs through a surcharge over a 12-year period. TNMP began collecting the surcharge on August 11, 2011 and deployment of advanced meters began in September 2011. TNMP completed its mass deployment of AMS in 2016 and has installed more than 242,000 advanced meters.

The PUCT approved interim adjustments to TNMP's transmission rates of $4.4 million in March 2015, $1.4 million in September 2015, $4.3 million in March 2016, $1.8 million in September 2016, $4.8 million in March 2017, and $4.7 million in September 2017. On January 30, 2018, TNMP filed an application to further update its transmission rates, which would increase revenues by $0.6 million annually. The application is pending before the PUCT. TNMP plans to file a general rate case in May 2018 and is prohibited from filing additional interim adjustments to its transmission rates while the general rate case is in progress. See Note 17.

Franchise Agreements

TNMP holds long-term, non-exclusive franchise agreements for its electric transmission and distribution services. These agreements have varying expiration dates and some have expired. TNMP intends to negotiate and execute new or amended franchise agreements with municipalities where the agreements have expired or will be expiring. Since TNMP is the exclusive provider of transmission and distribution services in most areas that it serves, the need to renew or renegotiate franchise agreements should not have a material adverse impact. TNMP also earns revenues from service provided to facilities in its service area that lie outside the territorial jurisdiction of the municipalities with which TNMP has franchise agreements.

Corporate and Other

The Corporate and Other segment includes PNMR holding company activities, primarily related to corporate level debt and the activities of PNMR Services Company. PNMR Services Company provides corporate services through shared services agreements to PNMR and all of PNMR's business units, including PNM and TNMP. These services are charged and billed at cost on a monthly basis to the business units. The activities of PNMR Development, NM Capital, and NMRD are also included in Corporate and Other.

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SOURCES OF POWER

PNM

Generation Capacity

As of January 1, 2018, the total net generation capacity of facilities owned or leased by PNM was 2,102 MW. PNM also obtains power under long-term PPAs for the power produced by Valencia, New Mexico Wind, Red Mesa Wind, the Lightning Dock Geothermal facility, and the NMRD-owned solar facility.

PNM's capacity in electric generating facilities, which are owned, leased, or under PPAs, in commercial service as of January 1, 2018 is:

Type	Name	Location	Generation Capacity (MW)

Coal	SJGS	Waterflow, New Mexico	562
Coal	Four Corners	Fruitland, New Mexico	200
Gas	Reeves Station	Albuquerque, New Mexico	154
Gas	Afton (combined cycle)	La Mesa, New Mexico	230
Gas	Lordsburg	Lordsburg, New Mexico	80
Gas	Luna (combined cycle)	Deming, New Mexico	189
Gas/Oil	Rio Bravo	Albuquerque, New Mexico	138
Gas	Valencia	Belen, New Mexico	158
Gas	La Luz	Belen, New Mexico	40
Nuclear	PVNGS	Wintersburg, Arizona	402
Solar	PNM-owned solar	Fifteen sites in New Mexico	107
Solar	NMRD-owned solar	Los Lunas, New Mexico	10
Wind	New Mexico Wind	House, New Mexico	204
Wind	Red Mesa Wind	Seboyeta, New Mexico	102
Geothermal	Lightning Dock Geothermal	Lordsburg, New Mexico	4
			2,580

Fossil-Fueled Plants

SJGS is operated by PNM and, until December 2017, consisted of four units. As discussed in Note 16, SJGS Units 2 and 3 were retired in December 2017 and the ownership interests in SJGS Unit 4 were restructured as of December 31, 2017. The table below presents the rated capacities and ownership interests of each participant in each unit of SJGS before and after these events:

Unit MW Capacity and Ownership Interests

	Prior to Restructuring				After Restructuring	
	Unit 1	**Unit 2**	**Unit 3**	**Unit 4**	**Unit 1**	**Unit 4**
Capacity (MW)	340	340	497	507	340	507
PNM [1]	50.000%	50.000%	50.000%	38.457%	50.000%	77.297%
Tucson	50.000	50.000	—	—	50.000	—
SCPPA	—	—	41.800	—	—	—
Tri-State	—	—	8.200	—	—	—
MSR	—	—	—	28.800	—	—
Anaheim	—	—	—	10.040	—	—
Farmington	—	—	—	8.475	—	8.475
Los Alamos	—	—	—	7.200	—	7.200
UAMPS	—	—	—	7.028	—	7.028
Total	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%

[1] After restructuring includes a 12.8% interest held as a merchant plant .

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Four Corners Units 4 and 5 are 13% owned by PNM. These units are jointly owned with APS, an APS affiliate, SRP, and Tucson and are operated by APS. PNM had no ownership interest in Four Corners Units 1, 2, or 3, which were shut down by APS on December 30, 2013. The Four Corners plant site is leased from the Navajo Nation and is also subject to an easement from the federal government. APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. The Navajo Nation approved these amendments in March 2011. The effectiveness of the amendments also required the approval of the DOI, as did a related federal rights-of-way grant, which was received in July 2015. An affiliate of APS acquired the 7% interest formerly owned by EPE on July 7, 2016. NTEC, an entity owned by the Navajo Nation, has the option to purchase the 7% interest. NTEC provided notice of its intent to exercise the option, but has not yet acquired the 7% interest. APS and NTEC are currently in discussions as to the future of the option transaction. See Note 16 for additional information about Four Corners.

PNM owns 100% of *Reeves, Afton, Rio Bravo, Lordsburg, and La Luz* and one-third of *Luna*. The remaining interests in Luna are owned equally by Tucson and Samchully Power & Utilities 1, LLC. PNM is entitled to the entire output of *Valencia* under a PPA. Reeves, Lordsburg, Rio Bravo, La Luz, and Valencia are used primarily for peaking power and transmission support. As discussed in Note 9, Valencia is a variable interest entity and is consolidated by PNM as required by GAAP.

Nuclear Plant

PNM is participating in the three units of *PVNGS*, also known as the Arizona Nuclear Power Project, with APS (the operating agent), SRP, EPE, SCE, SCPPA, and the Department of Water and Power of the City of Los Angeles. PNM is entitled to 10.2%, including portions that are leased to PNM, of the power and energy generated by PVNGS. See Note 7 for additional information concerning the PVNGS leases, including the renewal of the four PVNGS Unit 1 leases and one of the PVNGS Unit 2 leases and the purchase of the assets underlying the other three Unit 2 leases. Currently, PNM has ownership interests of 2.3% in Unit 1, 9.4% in Unit 2, and 10.2% in Unit 3 and has leasehold interests of 7.9% in Unit 1 and 0.8% in Unit 2. The lease payments for the leased portions of PVNGS are recovered through retail rates approved by the NMPRC. See Note 16 for information on other PVNGS matters, including the NMPRC's approval for PNM to include PVNGS Unit 3 as a jurisdictional resource to serve New Mexico retail customers beginning in 2018 and Note 17 for information concerning the NMPRC's treatment of the purchased assets and extended leases in PNM's NM 2015 Rate Case.

Solar

PNM completed several utility-owned solar PV facilities between 2011 and 2015. In addition, PNM completed its solar-storage demonstration project, which has a generation capacity of 0.5 MW. At December 31, 2017, PNM owns a total of 107 MW of solar facilities. PNMR Development began construction of 30 MW of new solar capacity in 2017. In

December 2017, interest in that 30 MW of solar capacity was transferred to NMRD, which is 50% owned by PNMR Development. As discussed in Note 17, PNM's 2018 renewable energy procurement plan includes the addition of 50 MW of PNM-owned solar PV facilities to be constructed in 2018 and 2019. In January 2018, the United States imposed a 30% tariff on certain imported solar panels. PNM is currently unable to predict the impact, if any, of this tariff on these projects. The NMPRC has approved a voluntary tariff that allows PNM retail customers to buy renewable electricity for a small monthly premium. Power from 1.5 MW of PNM's solar capacity is used to service load under the voluntary tariff.

Plant Operating Statistics

Equivalent availability of PNM's major base-load generating stations was:

Plant	Operator	2017	2016	2015
SJGS	PNM	84.1%	76.5%	67.4%
Four Corners	APS	50.6%	62.0%	77.8%
PVNGS	APS	91.9%	91.4%	94.2%

Joint Projects

SJGS, PVNGS, Four Corners, and Luna are joint projects each owned or leased by several different entities. Some participants in the joint projects are investor-owned entities, while others are privately, municipally, or co-operatively owned. Furthermore, participants in SJGS have varying percentage interests in different generating units within the project. The primary operating or participation agreements for the joint projects expire in July 2022 for SJGS, July 2041 for Four Corners, December 2046 for Luna, and November 2047 for PVNGS. SJGS and Four Corners are coal-fired generating plants that obtain their coal

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requirements from mines near the plants. An agreement for coal supply for SJGS, which expires on June 30, 2022, became effective on January 31, 2016. At that same time, an agreement to restructure the ownership in SJGS became effective. The restructuring agreement provided for certain participants in SJGS to exit ownership at December 31, 2017, by which time SJGS Units 2 and 3 were required to be permanently shut down. See Note 16 for a discussion of the restructuring of SJGS ownership. In December 2013, a coal supply arrangement for Four Corners that runs through July 6, 2031 was executed. As described above, Four Corners is situated on land under a lease from the Navajo Nation. Portions of PNM's interests in PVNGS Units 1 and 2 are held under leases. See Nuclear Plant above and Note 7 regarding PNM's actions related to these leases.

It is possible that other participants in the joint projects have circumstances and objectives that have changed from those existing at the time of becoming participants. The status of these joint projects is further complicated by the uncertainty surrounding the form of potential legislation and/or regulation of GHG, other air emissions, and CCBs, as well as the impacts of the costs of compliance and operational viability of all or certain units within the joint projects. It is unclear how these factors will enter into discussion and negotiations concerning the status of the joint projects as the expiration of basic operational agreements approaches.

PNM's 2017 IRP, which was filed on July 3, 2017, indicates that it would be cost beneficial to PNM's customers for PNM to retire its SJGS capacity in 2022 and for PNM to exit its ownership interest in Four Corners in 2031. See additional discussion of PNM's 2017 IRP and PNM's regulatory recovery of certain investments in Four Corners under the NM 2016 Rate Case, in Note 17. PNM can provide no assurance that its participation in the joint projects will continue in the manner that currently exists.

PPAs

In addition to generating its own power, PNM purchases power under long-term PPAs. PNM also purchases power in the forward, day-ahead, and real-time markets.

In 2002, PNM entered into a 25-year agreement to purchase all of the power and RECs generated by New Mexico Wind. PNM began receiving power from the project in June 2003. FPL owns and operates New Mexico Wind, which currently consists of 136 wind-powered turbines having an aggregate capacity of 204 MW on a site in eastern New Mexico. PNM also has a 20-year agreement to purchase energy and RECs from the Lightning Dock Geothermal facility built near Lordsburg, New Mexico. The current capacity of the facility is 4 MW. PNM's 2018 renewable plan filing, which was approved by the NMPRC on November 15, 2017, included requests to procure an additional 80 GWh in 2019 and 105 GWh in 2020 from a re-powering of New Mexico Wind and an additional 55 GWh in 2019 and 77 GWh in 2020 from a re-powering of Lightning Dock Geothermal. The PPAs now expire in 2044 for New Mexico Wind and 2042 for Lightning Dock Geothermal.

In June 2013, PNM entered into a 20-year PPA with Red Mesa Wind, LLC, a subsidiary of NextEra Energy Resources, LLC, to purchase all of the power and RECs produced by Red Mesa Wind beginning on January 1, 2015. Red Mesa Wind, LLC owns and operates the facility, which consists of 64 wind-powered turbines having an aggregate capacity of 102 MW on a site west of Albuquerque.

PNM and Tri-State have a hazard sharing agreement, which expires on May 31, 2022. Under this agreement, each party sells the other party 100 MW of capacity and energy from a designated generation resource on a unit contingent basis, subject to certain performance guarantees. Both the purchases and sales are made at the same market index price. This agreement serves to reduce the magnitude of each party's single largest generating hazard and assists in enhancing the reliability and efficiency of their respective operations. See Note 17 for details related to purchases and sales. Since PNM purchases and sells approximately the same amount of energy under the hazard sharing agreement, it is not included as a capacity resource in the above table.

As discussed in Note 1, PNMR Development and AEP OnSite Partners created NMRD on September 22, 2017 to pursue the acquisition, development, and ownership of renewable energy generation projects primarily in the State of New Mexico. PNMR Development and AEP OnSite Partners each have a 50% ownership interest in NMRD, a limited liability company. In December 2017, PNMR Development made a contribution to NMRD of its interest in three 10 MW solar facilities and assigned its interests in several agreements related to those facilities to NMRD. AEP OnSite Partners made a cash contribution to NMRD equal to 50% of the value of the 30 MW solar capacity, which cash was then distributed from NMRD to PNMR Development. Power from the 30 MWs of solar capacity will be sold to PNM under 25-year PPAs to supply renewable energy to a new data center being constructed in PNM's service territory by Facebook, Inc. (Note 17). At January 1, 2018, the first 10 MW of solar capacity was in commercial operation and the remaining capacity is expected to begin commercial operation by mid-2018.

In late 2017, PNM entered into three separate 25-year PPAs to purchase renewable energy and RECs to be used by PNM to supply additional renewable power to Facebook, Inc. These PPAs are subject to NMPRC approval and PNM made a filing requesting approval on January 17, 2018 (Note 17). These PPAs include the purchase of the power and RECs from:

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- Casa Mesa Wind, LLC, a subsidiary of NextEra Energy Resources, LLC., which is expected to be located near House, New Mexico, have a total capacity of 50 MW, and be operational at December 31, 2018
- A 166 MW portion of the La Joya Wind Project, owned by Avangrid Renewables, LLC, which is expected to be located near Estancia, New Mexico and be operational in November 2020
- Route 66 Solar Energy Center, LLC, a subsidiary of NextEra Energy Resources, LLC., which is expected to be located west of Albuquerque, New Mexico, have a total capacity of 50 MW, and be operational in December 2021

A summary of purchased power, excluding Valencia, is as follows:

	Year Ended December 31,		
	2017	2016	2015
Purchased under long-term PPAs			
MWh	1,574,716	1,211,852	599,562
Cost per MWh	$ 29.02	$ 28.26	$ 22.18
Other purchased power			
Total MWh	445,464	502,893	729,895
Cost per MWh	$ 31.74	$ 27.78	$ 28.94

TNMP

TNMP provides only transmission and distribution services and does not sell power.

FUEL AND WATER SUPPLY

PNM

The percentages (on the basis of KWh) of PNM's generation of electricity, including Valencia, fueled by coal, nuclear fuel, and gas and oil, and the average costs to PNM of those fuels per MMBTU were as follows:

	Coal		Nuclear		Gas and Oil	
	Percent of Generation	Average Cost	Percent of Generation	Average Cost	Percent of Generation	Average Cost
2017	56.5%	$ 2.16	31.9%	$ 0.64	9.2%	$ 3.02
2016	54.1%	$ 2.34	31.6%	$ 0.71	11.8%	$ 2.80
2015	53.3%	$ 2.88	32.6%	$ 0.70	12.6%	$ 2.91

In 2017, 2016, and 2015, 2.4%, 2.5%, and 1.5% of PNM's generation was from utility-owned solar, which has no fuel cost. In December 2017, SJGS Units 2 and 3 were retired and PNM assumed a greater interest in SJGS Unit 4, which results in a lower percentage of PNM's electric generation capacity being fueled by coal. The generation mix for 2018 is expected to be 44.3% coal, 29.4% nuclear, 23.8% gas and oil, and 2.5% utility-owned solar. Due to locally available natural gas and oil supplies, the utilization of locally available coal deposits, and the generally adequate supply of nuclear fuel, PNM believes that adequate sources of fuel are available for its generating stations into the foreseeable future. See Sources of Power – PNM – PPAs for information concerning the cost of purchased power. PNM recovers substantially all of it fuel and purchased power costs through the FPPAC.

Coal

A coal supply contract for SJGS, which expires on June 30, 2022, became effective on January 31, 2016. Substantially all of the benefits of lower coal pricing under the new contract are being passed through to PNM's customers under the FPPAC. Coal supply has not been arranged for periods after the existing contract expires. PNM believes there is adequate availability of coal resources to continue to operate SJGS. In 2018 and before entering into a binding agreement for post-2022 coal supply for SJGS, PNM must file its position in a NMPRC case to determine the extent to which SJGS should continue serving PNM's retail customers' needs after mid-2022.

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In late December 2013, a fifteen-year coal supply contract for Four Corners, which began in July 2016, was executed. The average coal price per ton under the new contract was approximately 51% higher in the twelve months ended June 30, 2017 than in the twelve months ended June 30, 2016, excluding disputed amounts discussed in Note 16. The contract provides for pricing adjustments over its term based on economic indices.

See Note 16 for additional information about PNM's coal supply. As discussed in Note 17, PNM's 2017 IRP indicated retiring PNM's remaining interest in SJGS in 2022 after the expiration of the current operating and coal supply agreements and exiting ownership in Four Corners after the end of its current coal supply agreement in 2031 would provide long-term cost savings to PNM's customers.

Natural Gas

The natural gas used as fuel for the electric generating plants is procured on the open market and delivered by third party transportation providers. The supply of natural gas can be subject to disruptions due to extreme weather events and/or pipeline or facility outages. PNM has contracted for firm gas transmission capacity to minimize the potential for disruptions due to extreme weather events. Certain of PNM's natural gas plants are generally used as peaking resources that are highly relied upon during periods of extreme weather, which also may be the times natural gas has the highest demand from other users. It is likely PNM's reliance on its natural gas generating resources will increase with the December 2017 retirement of SJGS Units 2 and 3, which will increase PNM's exposure to fluctuations in natural gas prices although substantially all gas costs are recovered through the FPPAC.

Nuclear Fuel and Waste

PNM is one of several participants in PVNGS. The PVNGS participants are continually identifying their future nuclear fuel resource needs and negotiating arrangements to fill those needs. The PVNG participants have contracted for 100% of PVNGS's requirements for uranium concentrates through 2023 and 50% of its requirements for 2024 and 2025. Additionally, PVNGS has contracts in various phases of negotiation to procure an additional 1.5 years supply of uranium concentrates, which would result in 100% of uranium concentrate requirements being assured through 2026. The PVNGS participants have also contracted for 100% of the requirements for conversion services through 2021 and 46% of its requirements for 2022 through 2025. Additional contracts are being negotiated for 4.3 years supply of conversion services, which would result in 100% of those services being assured through 2027. The PVNGS participants have also contracted for 100% of the requirements for enrichment services through 2020 and 20% of its enrichment services for 2021 through 2026. Additionally, PVNGS has several contracts in negotiation to procure an additional 4.3 years supply of enrichment services, which would result in 100% of those services being assured

through 2021, 90% in 2022 and 80% in 2023 through 2026. All of PVNGS's fuel assembly fabrication services are contracted through 2024.

The Nuclear Waste Policy Act of 1982 required the DOE to begin to accept, transport, and dispose of spent nuclear fuel and high level waste generated by the nation's nuclear power plants by 1998. The DOE's obligations are reflected in a contract with each nuclear power plant. The DOE failed to begin accepting spent nuclear fuel by 1998. APS (on behalf of itself and the other PVNGS participants) pursued legal actions for which settlements were reached. See Note 16 for information concerning these actions.

The DOE had planned to meet its disposal obligations by designing, licensing, constructing, and operating a permanent geologic repository at Yucca Mountain, Nevada. In March 2010, the DOE filed a motion to dismiss with prejudice its Yucca Mountain construction authorization application that was pending before the NRC. Several interested parties have intervened in the NRC proceeding. Additionally, a number of interested parties have filed a variety of lawsuits in different jurisdictions around the country challenging the DOE's authority to withdraw the Yucca Mountain construction authorization application. None of these lawsuits has been conclusively decided by the courts. However, in August 2013, the DC Circuit ordered the NRC to resume its review of the application with available appropriated funds.

On October 16, 2014, the NRC issued Volume 3 of the safety evaluation report developed as part of the Yucca Mountain construction authorization application. This volume addresses repository safety after permanent closure, and its issuance is a key milestone in the Yucca Mountain licensing process. Volume 3 contains the NRC staff's finding that the DOE's repository design meets the requirements that apply after the repository is permanently closed, including but not limited to the post-closure performance objectives in NRC's regulations. On December 18, 2014, the NRC issued Volume 4 of the safety evaluation report developed as part of the Yucca Mountain construction authorization application. This volume covers administrative and programmatic requirements for the repository and documents the staff's evaluation of whether the DOE's research and development and performance confirmation programs, as well as other administrative controls and systems, meet applicable NRC requirements. Volume 4 contains the staff's finding that most administrative and programmatic requirements in NRC regulations are met, except

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for certain requirements relating to ownership of land and water rights. Publication of Volumes 3 and 4 does not signal whether or when the NRC might authorize construction of the repository.

All spent nuclear fuel from PVNGS is being stored on-site. PVNGS has sufficient capacity at its on-site ISFSI to store all of the nuclear fuel that will be irradiated during the initial operating license periods, which end in November 2027. Additionally, PVNGS has sufficient capacity at its on-site ISFSI to store a portion of the fuel that will be irradiated during the extended license periods, which end in November 2047. If uncertainties regarding the United States government's obligation to accept and store spent fuel are not favorably resolved, the PVNGS participants will evaluate alternative storage solutions. These may obviate the need to expand the ISFSI to accommodate all of the fuel that will be irradiated during the extended license periods.

Water Supply

See Note 16 for information about PNM's water supply.

ENVIRONMENTAL MATTERS

Electric utilities are subject to stringent laws and regulations for protection of the environment by local, state, federal, and tribal authorities. In addition, PVNGS is subject to the jurisdiction of the NRC, which has the authority to issue permits and licenses and to regulate nuclear facilities in order to protect the health and safety of the public from radioactive hazards and to conduct environmental reviews. The liabilities under these laws and regulations can be material. In some instances, liabilities may be imposed without regard to fault, or may be imposed for past acts, whether or not such acts were lawful at the time they occurred. The construction expenditure projection (Note 14) includes the environmental upgrades at Four Corners discussed in Note 16 of $7.9 million in 2018. See MD&A – Other Issues Facing the Company – Climate Change Issues for information on GHG. In addition, Note 16 contains information related to the following matters, incorporated in this item by reference:

- PVNGS Decommissioning Funding
- Nuclear Spent Fuel and Waste Disposal
- Environmental Matters under the caption "The Clean Air Act"
- WEG v. OSM NEPA Lawsuit
- Navajo Nation Environmental Issues
- Cooling Water Intake Structures
- Effluent Limitation Guidelines
- Santa Fe Generating Station
- Environmental Matters under the caption "Coal Combustion Byproducts Waste Disposal"
- Environmental Matters under the caption "Coal Supply"

COMPETITION

Regulated utilities are generally not subject to competition from other utilities in areas that are under the jurisdiction of state regulatory commissions. In New Mexico, PNM does not have direct competition for services provided to its retail electric customers. In Texas, TNMP is not currently in any direct retail competition with any other regulated electric utility. However, PNM and TNMP are subject to customer conservation and energy efficiency activities, as well as initiatives to utilize alternative energy sources, including self-generation, or otherwise bypass the PNM and TNMP systems.

PNM is subject to varying degrees of competition in certain territories adjacent to or within the areas it serves. This competition comes from other utilities in its region as well as rural electric cooperatives and municipal utilities. PNM is involved in the generation and sale of electricity into the wholesale market although PNM has decided to stop pursuing wholesale generation contracts. PNM is subject to competition from regional utilities and merchant power suppliers with similar opportunities to generate and sell energy at market-based prices and larger trading entities that do not own or operate generating assets.

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EMPLOYEES

The following table sets forth the number of employees of PNMR, PNM, and TNMP as of December 31, 2017:

	PNMR	PNM	TNMP
Corporate [1]	396	—	—
PNM	938	938	—
TNMP	365	—	365
Total	1,699	938	365

(1) Represents employees of PNMR Services Company.

As of December 31, 2017, PNM had 495 employees in its power plant and operations areas that are currently covered by a collective bargaining agreement with the IBEW Local 611 that is in effect through April 30, 2020. As of December 31, 2017, TNMP had 198 employees represented by IBEW Local 66 covered by a collective bargaining agreement that is in effect through August 31, 2019. The wages and benefits for PNM and TNMP employees who are members of the IBEW are typically included in the rates charged to electric customers and consumers, subject to approval of the NMPRC and PUCT.

DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

Statements made in this filing that relate to future events or PNMR's, PNM's, or TNMP's expectations, projections, estimates, intentions, goals, targets, and strategies are made pursuant to the Private Securities Litigation Reform Act of 1995. Readers are cautioned that all forward-looking statements are based upon current expectations and estimates. PNMR, PNM, and TNMP assume no obligation to update this information.

Because actual results may differ materially from those expressed or implied by these forward-looking statements, PNMR, PNM, and TNMP caution readers not to place undue reliance on these statements. PNMR's, PNM's, and TNMP's business, financial condition, cash flows, and operating results are influenced by many factors, which are often beyond their control, that can cause actual results to differ from those expressed or implied by the forward-looking statements. These factors include:

- The ability of PNM and TNMP to recover costs and earn allowed returns in regulated jurisdictions, including the impacts of the NMPRC orders in PNM's NM 2015 Rate Case and NM 2016 Rate Case, appeals of those orders, the deferral of the issue of PNM's prudence of continuation of participation in Four Corners to PNM's next rate case and recovery of PNM's investments in that plant, and any actions resulting from PNM's 2017 IRP and the impact on service levels for PNM customers if the ultimate outcomes do not provide for the recovery of costs of operating and capital expenditures, as well as other impacts of federal or state regulatory and judicial actions
- The ability of the Company to successfully forecast and manage its operating and capital expenditures, including aligning expenditures with the revenue levels resulting from the ultimate outcomes in PNM's NM 2015 Rate Case and NM 2016 Rate Case, including appeals, and TNMP's rate case anticipated to be filed in May 2018 and supporting forecasts utilized in future test year rate proceedings
- The impacts on the electricity usage of customers and consumers due to performance of state, regional, and national economies, energy efficiency measures, weather, seasonality, alternative sources of power, and other changes in supply and demand
- Uncertainty surrounding the status of PNM's participation in jointly-owned generation projects, including the 2022 scheduled expiration of the operational and fuel supply agreements for SJGS, as well as the 2018 required NMPRC filing to determine the extent to which SJGS should continue serving PNM's retail customers beyond mid-2022 and any actions resulting from PNM's 2017 IRP, including regulatory recovery of undepreciated investments in the event the NMPRC orders generating facilities to be retired before currently estimated
- Uncertainty regarding the requirements and related costs of decommissioning power plants and reclamation of coal mines supplying certain power plants, as well as the ability to recover those costs from customers, including the potential impacts of the order in the NM 2015 Rate Case and NM 2016 Rate Case, appeals of those orders, and PNM's 2017 IRP
- Uncertainty regarding what actions PNM may take with respect to the generating capacity in PVNGS Units 1 and 2, which is under lease, at the expiration of the lease terms in 2023 and 2024, as well as the related treatment of the NMPRC for ratemaking purposes
- The Company's ability to access the financial markets in order to provide financing to repay or refinance debt as it comes due, as well as for ongoing operations and construction expenditures, including disruptions in the capital or credit markets, actions by ratings agencies, and fluctuations in interest rates, including any negative impacts that could result from the ultimate outcome in PNM's NM 2015 Rate Case and NM 2016 Rate Case, including appeals

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- The potential unavailability of cash from PNMR's subsidiaries due to regulatory, statutory, or contractual restrictions or subsidiary earnings or cash flows
- State and federal regulation or legislation relating to environmental matters, the resultant costs of compliance, and other impacts on the operations and economic viability of PNM's generating plants
- State and federal regulatory, legislative, executive, and judicial decisions and actions on ratemaking, tax, including the impacts and related uncertainties of tax reform enacted in 2017, and other matters
- Risks related to climate change, including potential financial risks resulting from climate change litigation and legislative and regulatory efforts to limit GHG
- Uncertainty surrounding counterparty credit risk, including financial support provided to facilitate the coal supply and ownership restructuring at SJGS
- The performance of generating units, transmission systems, and distribution systems, which could be negatively affected by operational issues, fuel quality, unplanned outages, extreme weather conditions, terrorism, cybersecurity breaches, and other catastrophic events
- Employee workforce factors, including cost control efforts and issues arising out of collective bargaining agreements and labor negotiations with union employees
- Variability of prices and volatility and liquidity in the wholesale power and natural gas markets
- Changes in price and availability of fuel and water supplies, including the ability of the mines supplying coal to PNM's coal-fired generating units and the companies involved in supplying nuclear fuel to provide adequate quantities of fuel
- The risks associated with completion of generation, transmission, distribution, and other projects
- Regulatory, financial, and operational risks inherent in the operation of nuclear facilities, including spent fuel disposal uncertainties
- The risk that FERC rulemakings or lack of additional capacity during peak hours may negatively impact the operation of PNM's transmission system
- The impacts of decreases in the values of marketable securities maintained in trusts to provide for decommissioning, reclamation, pension benefits, and other postretirement benefits, including potential increased volatility resulting from international developments
- The effectiveness of risk management regarding commodity transactions and counterparty risk
- The outcome of legal proceedings, including the extent of insurance coverage
- Changes in applicable accounting principles or policies

For information about the risks associated with the use of derivative financial instruments see Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk."

SECURITIES ACT DISCLAIMER

Certain securities described in this report have not been registered under the Securities Act of 1933, as amended, or any state securities laws and may not be reoffered or sold in the United States absent registration or an applicable exemption from the registration requirements of the Securities Act of 1933 and applicable state securities laws. This Form 10-K does

not constitute an offer to sell or the solicitation of an offer to buy any securities.

ITEM 1A. RISK FACTORS

The business and financial results of PNMR, PNM, and TNMP are subject to a number of risks and uncertainties, many of which are beyond their control, including those set forth below and in MD&A, Note 16, and Note 17. For other factors that may cause actual results to differ materially from those indicated in any forward-looking statement contained in this report, see Disclosure Regarding Forward Looking Statements in Item 1. Business. TNMP provides transmission and distribution services to REPs that provide electric service to consumers in TNMP's service territories. References to customers in the risk factors discussed below also encompass the customers of these REPs who are the ultimate consumers of electricity transmitted and distributed through TNMP's facilities.

Regulatory Factors

The profitability of PNMR's utilities depends on being able to recover their costs through regulated rates and earn a fair return on invested capital, including investments in its generating plants. PNM and TNMP are in a period of significant capital expenditures, including costs of replacing generating capacity as coal-fired plants are retired. While increased capital investments and other costs are placing upward pressure on rates, energy efficiency initiatives and a sluggish New Mexico economy are reducing usage by customers.

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The rates PNM charges its customers are regulated by the NMPRC and FERC. TNMP is regulated by the PUCT. The Company is in a period requiring significant capital investment and is projecting total construction expenditures for the years 2018-2022 to be $2,712.1 million. See Note 14. PNM and TNMP anticipate a trend toward increasing costs, for which it will have to seek regulatory recovery. These costs include or are related to:

- Costs of asset construction for generation, transmission, and distribution systems necessary to provide electric service, including new generation and transmission resources, as well as the cost to remove and retire existing assets
- Environmental compliance expenditures
- The regulatory mandate to acquire power from renewable resources
- Increased regulation related to nuclear safety
- Increased interest costs to finance capital investments
- Depreciation

At the same time costs are increasing, there are factors placing downward pressures on the demand for power, thereby reducing load growth and customer usage. These factors include:

- Changing customer behaviors, including increased emphasis on energy efficiency measures and utilization of alternative sources of power
- Rate design that is not driven by economics, which could influence customer behavior
- Unfavorable economic conditions
- Reductions in costs of self-generation energy resources and energy efficiency technology
- Reduced new sources of demand
- Unpredictable weather patterns

In 2017 and 2016, PNM experienced decreases in weather-normalized retail sales of 0.9% and 0.7%. The sales decreases reflect a continued sluggish economy in New Mexico. However, economic conditions in Albuquerque appear to have stabilized. The Albuquerque metro area is showing employment growth, although it continues to be lower than the national average. The economy in New Mexico continues to have mixed indicators and experience softness.

The combination of costs increasing relatively rapidly and the slowing of customer usage places upward pressure on the per unit prices that must be charged to recover costs. This upward pressure on unit prices could result in additional efforts by customers to reduce consumption through energy efficiency or to pursue self-generation or other alternative sources of power. Without timely cost recovery and the authorization to earn a reasonable return on invested capital, the Company's liquidity and results of operations could be negatively impacted.

Under New Mexico law, utilities may propose the use of a future test year ("FTY") in establishing rates. As with any forward looking financial information, a FTY presents challenges that are inherent in the forecasting process. Forecasts of both operating and capital expenditures necessitate reliance on many assumptions concerning future conditions and operating results. Accordingly, if rate requests based on a FTY cannot be successfully supported, cash flows and results of operations may be negatively impacted. This could result from not being able to withstand challenges from regulators and intervenors regarding the utility's capability to make reasonable forecasts.

As discussed in Note 17, PNM filed an application for a general rate increase in December 2014, which the NMPRC dismissed in May 2015, based on the Hearing Examiners recommendation, which cited procedural defects in the filing. In August 2015, PNM filed a new application (the "NM 2015 Rate Case") with the NMPRC for a general rate increase, including base non-fuel revenues of $121.5 million. The primary drivers of PNM's identified revenue deficiency were infrastructure investments and the recovery of those investment dollars, including depreciation based on an updated depreciation study, and declines in forecasted energy sales as a result of PNM's successful energy efficiency programs and other economic factors. The NMPRC issued an order authorizing an increase in non-fuel revenues of $61.2 million effective beginning in October 2016. The NMPRC disallowed recovery of PNM's capital investment in BDT equipment installed on SJGS Units 1 and 4, which is required by the NSR permit for SJGS (Note 16), and a portion of the acquisition costs for PNM's January 15, 2016 purchase of 64.1 MW of PVNGS Unit 2, which were previously leased to PNM, as well as the undepreciated costs of capitalized improvements made during the period that capacity was leased. PNM filed an appeal of these disallowances with the NM Supreme Court. Other parties to that rate case have filed cross-appeals to PNM's appeal in order to appeal other decisions of the NMPRC regarding issues in the rate case. On October 30, 2017, the NM Supreme Court heard oral argument on the case, but has not yet rendered a decision on the appealed matters and there is no required time frame for a decision to be issued.

In December 2016, PNM filed a request (the "NM 2016 Rate Case") for a general increase in rates of $99.2 million. The primary drivers of PNM's identified revenue deficiency were implementation of the plan for SJGS to comply with the CAA,

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including the shutdown of Units 2 and 3 of SJGS, recovery of 50% of the net book value of those units, and the inclusion in retail rates of PVNGS Unit 3 as replacement power (Note 16).

The requested increase also reflected new infrastructure investments, including the installation of SCRs at Four Corners, and declines in forecasted energy sales as a result of PNM's successful energy efficiency programs and other economic factors. PNM also proposed changes in rate design to better align electric rates with the actual costs to serve customers and encourage continued energy efficiency while proposing a rate mechanism that eliminates the disincentives associated with energy efficiency and load management programs. On May 23, 2017, PNM and several signatories filed a revised comprehensive stipulation, which reduced the non-fuel revenue increase to $62.3 million and provided that PNM would only earn a debt return on its investments in SCR technology at Four Corners. In January 2018, the NMPRC issued an order, which approved many aspects of the revised comprehensive stipulation with several modifications. These modifications include a requirement for PNM to reflect the impacts of recently enacted federal tax reform in rates beginning in 2018, a disallowance of PNM's ability to collect an equity return on its $90.1 million investment in SCRs at Four Corners and on $58.0 million of projected additional capital improvements at Four Corners, and a requirement that PNM reduce the $62.3 million non-fuel revenue requested increase by $4.4 million. The NMPRC deferred further consideration regarding the prudency of PNM's continuation of participation in Four Corners to PNM's next rate case. On February 7, 2018, NEE filed a notice of appeal with the NM Supreme Court asking the court to review the NMPRC's decisions in the NM 2016 Rate Case.

As discussed in Note 17, PNM filed its 2017 IRP on July 3, 2017. Key findings of the 2017 IRP include that retiring PNM's share of SJGS in 2022 after the expiration of the current operating and coal supply agreements would provide long-term cost savings for PNM's customers and that PNM exiting its ownership interest in Four Corners after its current coal supply agreement expires in 2031 would also provide long-term cost savings for customers. Retiring PNM's share of SJGS capacity and exiting Four Corners would require NMPRC approval of abandonment filings, which PNM would make at appropriate times in the future. NMPRC approval of new generation resources through CCN filings would also be required. The NMPRC has issued regulatory orders requiring depreciation (and resultant regulatory recovery) of significant portions of these resources through estimated lives of 2053 for SJGS and 2041 for Four Corners. If the NMPRC approves the retirement of SJGS in 2022 and exiting Four Corners in 2031, PNM will have significant un-recovered investments in those plants. PNM would seek NMPRC approval to recover those investments from ratepayers. At December 31, 2017, the net book values of PNM's investments in SJGS and Four Corners were $406.7 million and $165.3 million.

An adverse outcome in the NM 2015 Rate Case or the NM 2016 Rate Case, including the pending appeals of those orders before the NM Supreme Court, or the decision in PNM's next rate case on the issue regarding the prudency of PNM's continued participation in Four Corners could negatively impact PNM's financial position, results of operation, and cash flows. Likewise, if the NMPRC does not authorize appropriate recovery of any remaining investments in SJGS and Four Corners at the time those resources cease to be used to provide service to New Mexico ratepayers, including required future investments, and does not authorize recovery of the costs of obtaining power to replace those resources, PNM's financial position, results of operation, and cash flows could be negatively impacted.

PNM currently recovers the cost of fuel for its generation facilities through its FPPAC. A new coal supply contract for SJGS, which expires on June 30, 2022, became effective on January 31, 2016 and provides for lower coal pricing than under the prior contract. In December 2013, a new fifteen-year coal supply contract for Four Corners beginning in July 2016 was executed. The average coal price per MMBTU under the new contract for Four Corners was approximately 51% higher in the twelve months ended June 30, 2017 than in the twelve months ended June 30, 2016. The contracts provide for pricing adjustments over their terms based on economic indices. Although PNM believes substantially all costs under coal supply arrangements would continue to be recovered through the FPPAC, there can be no assurance that full recovery will be allowed.

PNM's regulatory approvals from the NMPRC, which are necessary for PNM to comply with the regional haze requirements of the CAA pertaining to SJGS, have been appealed to the NM Supreme Court. Furthermore, the NMPRC approval requires PNM to make a filing in 2018 to determine the extent to which SJGS should continue to serve PNM's retail customers after June 30, 2022, on which date the SJPPA and the current coal supply agreement will expire. PNMR has counterparty credit risk in connection with financial support provided to facilitate the coal supply arrangement for SJGS. Adverse developments from these factors could have a negative impact on the business, financial condition, results of operations, and cash flows of PNM and PNMR.

SJGS, which currently comprises 26.7% of PNM's owned and leased generation capacity and is its largest generation resource, is subject to the CAA. As discussed in Note 16, in December 2015, the NMPRC approved a plan enabling SJGS to comply with the CAA (the "BART Approval"). The plan required the shutdown of SJGS Units 2 and 3 by December 31, 2017 and the shutdown was completed by that date. NEE, an intervenor in the NMPRC proceeding regarding the approval of the plan, has appealed the BART Approval to the NM Supreme Court. NEE has also filed a complaint with the NMPRC against PNM regarding the financing provided by NM Capital, a subsidiary of PNMR, to facilitate the sale of SJCC, which is discussed below and described under Coal Supply in Note 16. The complaint alleges that PNM failed to comply with its discovery obligation in

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the SJGS abandonment case and requests the NMPRC to investigate whether the financing transactions could adversely affect PNM's ability to provide electric service to its retail customers. The NMPRC has taken no action on this matter. If the NM Supreme Court were to negate the BART Approval, it is unclear what the impact would be since SJGS Units 2 and 3 have been retired and ownership of SJGS has been restructured.

The BART Approval also requires PNM to make a filing with the NMPRC no later than December 31, 2018, and before entering into an agreement for post-2022 coal supply for SJGS, setting forth its position in a case to determine the extent to which SJGS should continue serving PNM's retail customers' needs after mid-2022. The existing SJPPA among the SJGS participants, which governs the operations of SJGS, expires on July 1, 2022 and the new SJGS CSA for coal supply at SJGS described in Note 16 expires on June 30, 2022. PNM has the option to extend the SJGS CSA, subject to negotiation of the term of the extension and compensation to the miner. In order to extend, PNM must give written notice of that intent to the miner by July 1, 2018 and the parties must agree to the terms of the extension by January 1, 2019.

As discussed in Note 17, PNM's 2017 IRP indicates that retiring PNM's share of SJGS in 2022 after the expiration of the current operating and coal supply agreements and exiting ownership in Four Corners after the current coal supply agreement expires in 2031 would provide long-term cost savings for PNM's customers. The 2017 IRP addresses a 20-year planning period, from 2017 through 2036, and includes an action plan describing PNM's plan to implement the 2017 IRP in the four-year period following its filing.

The restructuring of SJGS ownership and obtaining the new coal supply for SJGS were integral components of the process to achieve compliance with the CAA at SJGS. The effectiveness of the new SJGS CSA was dependent on the closing of the purchase of the existing coal mine operation by a new mine operator. In support of the closing of the mine purchase, NM Capital provided a loan of $125.0 million to the purchaser, which has been organized to be a bankruptcy-remote entity. In addition, PNMR has an arrangement with a bank under which the bank has issued $30.3 million of letters of credit in favor of sureties in order for the sureties to post reclamation bonds that are required under the mine's operating permit. See Note 6 and Note 16.

The inability to operate SJGS or Four Corners or their early retirement would require approval of the NMPRC and would require PNM to obtain power from other sources in order to serve the needs of its customers. There can be no assurance that the NMPRC would approve early retirement or that recovery of any undepreciated investments through rates charged to customers would be authorized. In addition, there can be no assurance that adequate sources of replacement power would be available, that adequate transmission capabilities would be available to bring that power into PNM's service territory, or whether the cost of obtaining those resources would be economic. Any such events would negatively impact PNM's financial position, results of operation, and cash flows unless the NMPRC authorized the collection from customers of any un-recovered costs related to SJGS and Four Corners, as well as costs of obtaining replacement power.

It is also possible that unsatisfactory outcomes of these matters, the financial impact of climate change regulation or legislation, other environmental regulations, the result of litigation, the adequacy and timeliness of cost recovery mechanisms, and other business considerations, could jeopardize the economic viability of SJGS and/or Four Corners or the ability of individual participants to continue participation in them.

PNMR's utilities are subject to numerous federal, state, and local environmental laws and regulations, including those related to climate change, which may impose significant compliance costs and may significantly limit or affect their operations and financial results.

Environmental policies and regulations remain significant concerns for PNMR. Compliance with federal, state, and local environmental laws and regulations, including those addressing climate change, air quality, CCBs, discharges of wastewater originating from fly ash and bottom ash handling facilities, cooling water, and other matters, may result in increased capital, operating, and other costs, particularly with regard to enforcement efforts focused on power plant emission obligations. These costs could include remediation, containment, civil liability, and monitoring expenses. The Company cannot predict how it would be affected if existing environmental laws and regulations were to be repealed, revised, or reinterpreted, or if new environmental statutes and rules were to be adopted. See Note 16 and the Climate Change Issues subsection of the Other Issues Facing the Company section of MD&A.

Under the Obama Administration, EPA's Clean Power Plan mandated standards of performance that would limit carbon dioxide emissions from existing power plants. Individual states would develop and implement plans to ensure compliance with the proposed standards. Currently, the Clean Power Plan is stayed and under review. The Trump Administration has also proposed to repeal the Clean Power Plan and is considering a possible replacement rule. In addition, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement. Therefore, PNMR is dealing with an uncertain regulatory and policy environment. While EPA and other federal agencies may be seeking to reduce climate change regulations,

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some state agencies, environmental advocacy groups, and other organizations have been focusing considerable attention on GHG from power generation facilities. PNM currently depends on fossil-fueled generation for a significant portion of its electricity. As discussed under Climate Change Issues, this type of generation could be subject to future EPA or state regulations requiring GHG reductions. This includes new, existing, and modified or reconstructed EGUs. The uncertainty regarding climate change regulation presents challenges and represents a possible shift of greater authority to the states to make decisions and issue and enforce regulations. Federal and/or state regulations could result in additional operating restrictions on facilities and increased generation and compliance costs.

CCBs from the operation of SJGS are currently being used in the reclamation of a surface coal mine. These CCBs consist of fly ash, bottom ash, and gypsum. Any new regulation that would affect the reclamation process, including mine use of CCBs being classified as hazardous waste, could significantly increase the costs of the disposal of CCBs and the costs of mine reclamation. See Note 16.

A regulatory body may identify a site requiring environmental cleanup and designate PNM or TNMP as a responsible party. There is also uncertainty in quantifying exposure under environmental laws that impose joint and several liability on all potentially responsible parties. Failure to comply with environmental laws and regulations, even if such non-compliance is caused by factors beyond PNM's or TNMP's control, may result in the assessment of civil or criminal penalties and fines.

BART determinations have been made for both SJGS and Four Corners under the program to address regional haze in the "four corners" area, which would reduce the levels of NOx emitted at both plants. Significant capital expenditures have been made at SJGS and are continuing at Four Corners for the installation of control technology resulting in operating costs increases. PNMR and its operating subsidiaries may underestimate the costs of environmental compliance, liabilities, and litigation due to the uncertainty inherent in these matters. Although there is uncertainty about the timing and form of the implementation of EPA's regulations regarding climate change, including the Clean Power Plan, how CCBs used for mine reclamation will be regulated, and regulation of other power plant emissions, including changes to the ambient air quality standards, such regulations could have a material impact on operations. The Company is unable to estimate these costs due to the many uncertainties associated with, among other things, the nature and extent of future regulations and changes in existing regulations, including the changes in regulatory policy under the Trump Administration. Timely regulatory recovery of costs associated with any environmental-related regulations would be needed to maintain a strong financial and operational profile. The above factors could adversely affect the Company's business, financial position, results of operations, and liquidity.

PNMR, PNM, and TNMP are subject to complex government regulation unrelated to the environment, which may have a negative impact on their businesses, financial position and results of operations.

To operate their businesses, PNMR, PNM, and TNMP are required to have numerous permits and approvals from a variety of regulatory agencies. Regulatory bodies with jurisdiction over the utilities include the NMPRC, NMED, PUCT, TCEQ, ERCOT, FERC, NRC, EPA, and NERC. Oversight by these agencies covers many aspects of the Company's utility operations including, but not limited to: location, construction, and operation of facilities; the purchase of power under long-term contracts; conditions of service; the issuance of securities; and rates charged to customers. FERC has issued a number of rules pertaining to preventing undue discrimination in transmission services and electric reliability standards. The significant level of regulation imposes restrictions on the operations of the Company and causes the incurrence of substantial compliance costs. PNMR and its subsidiaries are unable to predict the impact on their business and operating results from future actions of any agency regulating the Company. Changes in existing regulations or the adoption of new ones could result in additional expenses and/or changes in business operations. Failure to comply with any applicable rules, regulations or decisions may lead to customer refunds, fines, penalties, and other payments, which could materially and adversely affect the results of operations and financial condition of PNMR and its subsidiaries.

Operational Factors

Customer electricity usage could be reduced by increases in prices charged and other factors. This could result in underutilization of PNM's generating capacity, as well as underutilization of the capacities of PNM's and TNMP's transmission and distribution systems. Should this occur, operating and capital costs might not be fully recovered, and financial performance could be negatively impacted.

A number of factors influence customers' electricity usage. These factors include, but are not limited to:

- Rates charged by PNM and TNMP
- Rates charged by REPs utilizing TNMP's facilities to deliver power
- Energy efficiency initiatives

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- Availability and cost of alternative sources of power
- National, regional, or local economic conditions

These factors and others may prompt customers to institute additional energy efficiency measures or take other actions that would result in lower power consumption. If customers bypass or underutilize PNM's and TNMP's facilities through self-generation, renewable, or other energy resources, technological change, or other measures, revenues would be negatively impacted.

PNM's and TNMP's service territories include several military bases and federally funded national laboratories, as well as large industrial customers that have significant direct and indirect impacts on the local economies where they operate. The Company does not directly provide service to any of the military bases or national laboratories, but does provide service to large industrial customers. The Company's business could be hurt from the impacts on the local economies associated with these customer groups, as well as directly from the large industrial customers, for a number of reasons, including:

- Federally-mandated base closures or significant curtailment of the activities at the bases or national laboratories
- Closure of industrial facilities or significant curtailment of their activities

Another factor that could negatively impact the Company is that proposals are periodically advanced in various localities to municipalize, or otherwise take over PNM's facilities, which PNM believes would require state legislative action to implement, or to establish new municipal utilities in areas currently served by PNM. If any such initiative is successful, the result could be a material reduction in the usage of the facilities, a reduction in rate base, and reduced earnings.

Should any of the above factors result in facilities being underutilized, the Company's financial position, operational results, and cash flows could be significantly impacted.

Advances in technology could make electric generating facilities less competitive.

Research and development activities are ongoing for new technologies that produce power or reduce power consumption. These technologies include renewable energy, customer-oriented generation, energy storage, and energy efficiency. PNM generates power at central station power plants to achieve economies of scale and produce power at a cost that is competitive with rates established through the regulatory process. There are distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines, and solar cells, which have become increasingly cost competitive. It is possible that advances in technology will continue to reduce the costs of these alternative methods of producing power to a level that is competitive with that of central station power production. Advances in the capabilities for energy storage could also have impacts on power production by PNM as it would be increasingly simple to reduce peak usage by dispatching battery systems. This could result in demand reduction that could negatively impact revenue and/or result in underutilized assets that had been built to serve peak usage. If these technologies become cost competitive and achieve economies of scale, PNM's energy sales could be eroded, and the value of its generating facilities could be reduced. Advances in technology could also change the channels through which electric customers purchase or use power, which could reduce the Company's sales and revenues or increase expenses. These advances can also create more uncertainty in load shapes and forecasts, which could have implications for generation and system planning.

Costs of decommissioning, remediation, and restoration of nuclear and fossil-fueled power plants, as well as reclamation of related coal mines, could exceed the estimates of PNMR and PNM as well as the amounts PNM recovers from its ratepayers, which could negatively impact results of operations and liquidity.

PNM has interests in a nuclear power plant, two coal-fired power plants, and several natural gas-fired power plants. PNM is obligated to pay for the costs of decommissioning its share of the power plants. PNM is also obligated to pay for its share of the costs of reclamation of the mines that supply coal to the coal-fired power plants. Likewise, other owners or participants are responsible for their shares of the decommissioning and reclamation obligations and it is important to PNM that those parties fulfill their obligations. Rates charged by PNM to its customers, as approved by the NMPRC, include a provision for recovery of certain costs of decommissioning, remediation, reclamation, and restoration. The NMPRC has established a cap on the amount of costs for the final reclamation of the surface coal mines that may be recovered from customers. PNM records estimated liabilities for its share of the legal obligations for decommissioning and reclamation in accordance with GAAP. These estimates include many assumptions about future events and are inherently imprecise. As discussed in Note 17, PNM's 2017 IRP indicates that retiring PNM's share of SJGS in 2022 and exiting PNM's ownership interest in Four Corners in 2031 would provide long-term cost savings for customers. Should those events occur, the costs of reclamation for the coal mines serving those plants would increase and the increases could be significant. In the event any of these costs exceed current estimates, results of operations could be negatively impacted unless the NMPRC authorizes recovery of the additional costs from ratepayers. In addition, the NMPRC's order in the NM 2015 Rate Case (Note 17) disallows recovery of future contributions for the decommissioning of certain portions of PVNGS. PNM has appealed the NMPRC decision in the NM 2015 Rate Case, oral argument has been held, and the appeal is

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pending before the NM Supreme Court. An adverse outcome of the appeal could negatively impact PNM's future results of operations, cash flows, and liquidity.

The costs of decommissioning any nuclear power plant are substantial. PNM is responsible for all decommissioning obligations related to its entire interest in PVNGS, including portions under lease both during and after termination of the leases. PNM maintains trust funds designed to provide adequate financial resources for decommissioning PVNGS and for reclamation of the coal mines serving SJGS and Four Corners at the end of their expected lives. However, if the PVNGS units are decommissioned before their planned date or the coal mines are shut down sooner than expected, these funds may prove to be insufficient.

The financial performance of PNMR, PNM, and TNMP may be adversely affected if power plants and transmission and distribution systems do not operate reliably and efficiently.

The Company's financial performance depends on the successful operation of PNM's generation assets, as well as the transmission and distribution systems of PNM and TNMP. As indicated above, SJGS Units 2 and 3 were shut down in December 2017. Also, PNM's 2017 IRP indicates that retiring PNM's share of SJGS in 2022 and that PNM exiting its ownership interest in Four Corners in 2031 would also provide long-term cost savings for customers. These actions will increase PNM's dependency on other generation resources, particularly PVNGS, and will reduce PNM's flexibility in managing those resources. Unscheduled or longer than expected maintenance outages, breakdown or failure of equipment or processes due to aging infrastructure, temporary or permanent shutdowns to achieve environmental compliance, other performance problems with the electric generation assets, severe weather conditions, accidents and other catastrophic events, acts of war or terrorism, cybersecurity attacks, disruptions in the supply, quality, and delivery of fuel and water supplies, and other factors could result in PNM's load requirements being larger than available system generation capacity. Assured supplies of water are important for PNM's generating plants. Water in the southwestern United States is limited and there are conflicting claims regarding water rights. In addition, the "four corners" region where SJGS and Four Corners are located is prone to drought conditions, which could potentially affect the plants' water supplies. Unplanned outages of generating units and extensions of scheduled outages occur from time to time and are an inherent risk of the Company's business. If these were to occur, PNM would be required to purchase electricity in either the wholesale market or spot market at the then-current market price. There can be no assurance that sufficient electricity would be available at reasonable prices, or available at all. The failure of transmission or distribution facilities may also affect PNM's and TNMP's ability to deliver power. These potential generation, distribution, and transmission problems, and any service interruptions related to them, could result in lost revenues and additional costs.

PNMR, PNM, and TNMP are subject to information security breaches and risks of unauthorized access to their information and operational technology systems as well as physical threats to assets.

The Company faces the risk of physical and cybersecurity attacks, both threatened and actual, against generation facilities, transmission and distribution infrastructure used to transport power, information technology systems, and network infrastructure, which could negatively impact the ability of the Company to generate, transport, and deliver power, or otherwise operate facilities in the most efficient manner or at all.

The utility industry in which the Company operates is a highly regulated industry that requires the continued operation of sophisticated information technology systems and

network infrastructure, some of which are deemed to be critical infrastructure under NERC guidelines. Certain of the Company's systems are interconnected with external networks. In the regular course of business, the utilities handle a range of sensitive security and customer information. PNM and TNMP are subject to the rules of various agencies concerning safeguarding and maintaining the confidentiality of this information. Despite steps the Company may take to detect, mitigate and/or eliminate cybersecurity threats and respond to data security incidents, the techniques used by those who wish to obtain unauthorized access, and possibly disable or sabotage systems and/or abscond with confidential information and data, change frequently and the Company may not be able to protect against such actions.

In the event a party desires to disrupt the bulk power or transmission systems in the United States, the Company's computer and operating systems could be subject to physical or cybersecurity attack. Although the Company has implemented security measures, critical infrastructure, including information and operational technology systems, are vulnerable to disability, failures, or unauthorized access, which could occur as a result of malicious compromise, employee error, and/or employee misconduct. A successful physical or cybersecurity attack or other similar failure of the systems could impact the reliability of PNM's generation and PNM's and TNMP's transmission and distribution systems, including the possible unauthorized shutdown of facilities. Such an event could lead to significant disruptions of business operations, including the Company's ability to generate, transport, and deliver power to serve customers, to bill customers, and to process other financial information. Moreover, a breach of the Company's information technology systems could also lead to the loss and destruction of confidential and proprietary data, customer and employee data (which may include personally identifiable information such as names, addresses, phone numbers, email addresses

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and payment account information), trade secrets, intellectual property and supplier data, and could disrupt business operations which could harm the Company's reputation and financial results, as well as potential increased regulatory oversight, litigation, fines, and other remedial action. The costs incurred to investigate and remediate a physical or cybersecurity attack could be significant. A physical or cybersecurity attack on the Company's critical infrastructure could have a material adverse impact on the operations and financial condition of PNMR, PNM, and TNMP.

There are inherent risks in the ownership and operation of nuclear facilities.

PNM has a 10.2% undivided interest in PVNGS, including interests in Units 1 and 2 held under leases. PVNGS represents 19.1% of PNM's total owned and leased generating capacity. PVNGS is subject to environmental, health, and financial risks, including, but not limited to:

- The ability to obtain adequate supplies of nuclear fuel and water
- The ability to dispose of spent nuclear fuel
- Decommissioning of the plant (see above)
- Securing the facilities against possible terrorist attacks
- Unscheduled outages due to equipment failures

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. Events at nuclear facilities of other operators or which impact the industry generally may lead the NRC to impose additional requirements and regulations on all nuclear generation facilities, including PVNGS. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit and to promulgate new regulations that could require significant capital expenditures and/or increase operating costs.

In the event of noncompliance with its requirements, the NRC has the authority to impose a progressively increasing inspection regime that could ultimately result in the shutdown of a unit, civil penalties, or both, depending upon the NRC's assessment of the severity of the situation, until compliance is achieved. Increased costs resulting from penalties, a heightened level of scrutiny, and/or implementation of plans to achieve compliance with NRC requirements could adversely affect the financial condition, results of operations, and cash flows of PNMR and PNM. Although PNM has no reason to anticipate a serious nuclear incident at PVNGS, if an incident did occur, it could materially and adversely affect PNM's results of operations and financial condition.

PNM has external insurance coverage to minimize its financial exposure to some risks. However, it is possible that liabilities associated with nuclear operations could exceed the amount of insurance coverage. See Note 16.

Demand for power could exceed supply capacity, resulting in increased costs for purchasing capacity in the open market or building additional generation facilities.

PNM is obligated to supply power to retail customers and certain wholesale customers. At peak times, power demand could exceed PNM's available generation capacity, particularly if PNM's power plants are not performing as anticipated. In addition, SJGS units 2 and 3 were shut down in December 2017 and PNM's 2017 IRP indicates that it would save customers money for PNM to shut down the remaining two units of SJGS in 2022 and to exit ownership in Four Corners in 2031. SJGS and Four Corners comprise a significant portion of PNM's base load generation capacity and their retirement would increase reliance on other existing or new generating resources. Market forces, competitive forces, or adverse regulatory actions may require PNM to purchase capacity on the open market or build additional generation capabilities. Regulators or market conditions may not permit PNM to pass all of these purchases or construction costs on to customers. If that occurs, PNM may not be able to fully recover these costs or there may be a lag between when costs are incurred and when regulators permit recovery in customers' rates. These situations could have negative impacts on results of operations and cash flows.

General Economic and Weather Factors

General economic conditions of the nation and/or specific areas can affect the Company's customers and suppliers. Economic recession or downturn may result in decreased consumption by customers and increased bad debt expense, and could also negatively impact suppliers, all of which could negatively impact the Company.

Economic activity in the service territories of PNMR subsidiaries is a key factor in their performance. Decreased economic activity can lead to declines in energy consumption, which could adversely affect future revenues, earnings, and growth. Higher unemployment rates, both in the Company's service territories and nationwide, could result in commercial customers ceasing operations and lower levels of income for residential customers. These customers might then be unable to pay their bills on time,

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which could increase bad debt expense and negatively impact results of operations and cash flows. Economic conditions also impact the supply and/or cost of commodities and materials needed to construct or acquire utility assets or make necessary repairs.

Uncertainties regarding the impacts and implementation of recent United States tax reform legislation may negatively impact PNMR's, PNM's, and TNMP's businesses, financial position, results of operations, and cash flows.

On December 22, 2017, comprehensive changes in United States federal income taxes were enacted through legislation commonly known as the Tax Cuts and Jobs Act (the "Tax Act"). Among other things, the Tax Act reduces the federal corporate income tax rate from 35% to 21% effective January 1, 2018, eliminates federal bonus depreciation for utilities effective September 28, 2017, and, effective January 1, 2018, limits interest deductibility for non-utility businesses and limits the deductibility of certain officer compensation. In December 2017, the SEC issued Staff Accounting Bulletin No. 118, which provides guidance to address the application of GAAP to reflect the Tax Act in circumstances where all information and analysis of the Tax Act is not yet available or complete. This bulletin provides for up to a one-year period in which to complete the required analyses and accounting for the impacts of the Tax Act.

In accordance with GAAP, the Company adjusted its deferred tax assets and liabilities as of December 31, 2017 resulting in increases in regulatory liabilities related to adjustments of net deferred tax liabilities associated with regulated activities, which will be returned to PNM's and TNMP's ratepayers over time, and increases in income tax expense related to adjustments of net deferred tax assets related to items excluded from regulated activities. The Company believes it has made reasonable estimates of the effects of the Tax Act as of December 31, 2017 and reflected the impacts in the Consolidated Financial Statements.

The Company currently believes that the impacts of the Tax Act will not significantly impact the future earnings of regulated activities due to the ratemaking process. However, cash flows will be reduced in the near term due to less cash being received from customer billings as the benefits of the reduced corporate income tax are passed on to ratepayers, but without a corresponding reduction in income taxes paid due to the Company having a net operating loss carryforward for income taxes purposes. In addition, the income tax benefit of net losses for the unregulated activities of PNMR, primarily interest expense on holding company debt, will be negatively impacted by the reduced rate. Furthermore, there is uncertainty regarding the interpretation of the provision of the Tax Act that limits the deductibility of interest for non-utility businesses under the interest expense allocation methodology that is generally used by the utility industry.

It is possible that changes to U.S. Treasury regulations, IRS interpretations of the provisions of the Tax Act, actions by the NMPRC, PUCT, and FERC, or the Company's further analysis of historical records could cause the estimates of the impacts recorded as of December 31, 2017 to change or cause the Company's current assessment of future impacts to change. Any such change could adversely affect the Company's financial position, results of operations, and cash flows.

The operating results of PNMR and its operating subsidiaries fluctuate on a seasonal and quarterly basis, as well as being affected by weather conditions, including regional drought.

Electric generation, transmission, and distribution are generally seasonal businesses that vary with the demand for power. With power consumption typically peaking during the hot summer months, revenues traditionally peak during that period. As a result, quarterly operating results of PNMR and its operating subsidiaries vary throughout the year. In addition, PNMR and its operating subsidiaries have historically had lower revenues resulting in lower earnings when weather conditions are milder. Unusually mild weather in the future could reduce the revenues, net earnings, and cash flows of the Company.

Drought conditions in New Mexico, especially in the "four corners" region, where SJGS and Four Corners are located, may affect the water supply for PNM's generating plants. If inadequate precipitation occurs in the watershed that supplies that region, PNM may have to decrease generation at these plants. This would require PNM to purchase power to serve customers and/or reduce the ability to sell excess power on the wholesale market and reduce revenues. Drought conditions or actions taken by the court system, regulators, or legislators could limit PNM's supply of water, which would adversely impact PNM's business. Although SJGS and Four Corners participate in voluntary shortage sharing agreements with tribes and other water users in the "four corners" region, PNM cannot be certain these contracts will be enforceable in the event of a major drought or that it will be able to renew these contracts in the future.

TNMP's service areas are exposed to extreme weather, including high winds, drought, flooding, ice storms, and periodic hurricanes. Extreme weather conditions, particularly high winds and severe thunderstorms, also occur periodically in PNM's service areas. These severe weather events can physically damage facilities owned by TNMP and PNM. Any such occurrence both disrupts the ability to deliver energy and increases costs. Extreme weather can also reduce customers' usage and demand for energy. These factors could negatively impact results of operations and cash flows.

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Financial Factors

PNMR may be unable to meet its ongoing and future financial obligations and to pay dividends on its common stock if its subsidiaries are unable to pay dividends or distributions to PNMR.

PNMR is a holding company and has no operations of its own. PNMR's ability to meet its financial obligations and to pay dividends on its common stock primarily depends on the net income and cash flows of PNM and TNMP and their capacity to pay upstream dividends or distributions. Prior to providing funds to PNMR, PNM and TNMP have financial and regulatory obligations that must be satisfied, including among others, debt service and, in the case of PNM, preferred stock dividends.

The NMPRC has placed certain restrictions on the ability of PNM to pay dividends to PNMR, including that PNM cannot pay dividends that cause its debt rating to fall below investment grade. The NMPRC has also restricted PNM from paying dividends in any year, as determined on a rolling four-quarter basis, in excess of net earnings without prior NMPRC approval. PNM is permitted to pay dividends to PNMR from prior equity contributions made by PNMR. Additionally, the Company's financing agreements generally include a covenant to maintain a debt-to-capital ratio that does not exceed 65%, PNM has various financial covenants that limit the transfer of assets, through dividends or other means and the Federal Power Act imposes certain restrictions on dividends paid by public utilities, including that dividends cannot be paid from paid-in capital.

Further, the ability of PNMR to declare dividends depends upon:

- The extent to which cash flows will support dividends
- The Company's financial circumstances and performance
- Decisions of the NMPRC and PUCT in various regulatory cases currently pending or that may be docketed in the future, including the outcome of appeals of those decisions
- Conditions imposed by the NMPRC, PUCT, or Federal Power Act
- The effect of federal regulatory decisions and legislative acts
- Economic conditions in the United States and in the Company's service areas
- Future growth plans and the related capital requirements
- Other business considerations

Disruption in the credit and capital markets may impact the Company's strategy and ability to raise capital.

As discussed in MD&A – Liquidity and Capital Resources, PNMR and its subsidiaries rely on access to both short-term and longer-term capital markets as sources of liquidity for any capital requirements not satisfied by cash flow from operations. In general, the Company relies on its short-term credit facilities as the initial source to finance construction

expenditures. This results in increased borrowings under the facilities over time. The Company is currently projecting total construction expenditures for the years 2018-2022 to be $2,712.1 million. If PNMR or its operating subsidiaries are not able to access capital at competitive rates, or at all, PNMR's ability to finance capital requirements and implement its strategy will be limited. Disruptions in the credit markets, which could negatively impact the Company's access to capital, could be caused by:

- An economic recession
- Declines in the health of the banking sector generally, or the failure of specific banks who are parties to the Company's credit facilities
- Deterioration in the overall health of the utility industry
- The bankruptcy of an unrelated energy company
- War, terrorist attacks, or cybersecurity attacks, or threatened attacks

If the Company's cash flow and credit and capital resources are insufficient to fund capital expenditure plans, the Company may be forced to delay important capital investments, sell assets, seek additional equity or debt capital, or restructure debt. In addition, insufficient cash flows and capital resources may result in reductions of credit ratings. This could negatively impact the Company's ability to incur additional indebtedness on acceptable terms and would result in an increase in the interest rates applicable under the Company's credit facilities. The Company's cash flow and capital resources may be insufficient to pay interest and principal on debt in the future. If that should occur, the Company's capital raising or debt restructuring measures may be unsuccessful or inadequate to meet scheduled debt service obligations. This could cause the Company to default on its obligations and further impair liquidity.

Reduction in credit ratings or changing rating agency requirements could materially and adversely affect the Company's growth, strategy, business, financial position, results of operations, and liquidity.

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PNMR, PNM, and TNMP cannot be sure that any of their current credit ratings will remain in effect for any given period of time or that a rating will not be put under review for a downgrade, lowered, or withdrawn entirely by a rating agency. On January 16, 2018, S&P changed the outlook for PNMR, PNM and TNMP from stable to negative while affirming the investment grade ratings of each entity. Downgrades or changing requirements could result in increased borrowing costs due to higher interest rates on current borrowings or future financings, a smaller potential pool of investors, and decreased funding sources. Such conditions also could require the provision of additional support in the form of letters of credit and cash or other collateral to various counterparties.

Declines in values of marketable securities held in trust funds for pension and other postretirement benefits and in the NDT and mine reclamation trusts could result in sustained increases in costs and funding requirements for those obligations, which may affect operational results.

Through 2017, the Company targeted 21% of its pension trust funds and 70% of its trust funds for other postretirement benefits to be invested in marketable equity securities. Historically, over one-half of funds held in the NDT and mine reclamation trusts have been invested in marketable equity securities. Due to the current funded status of the NDT and recent overall market performance, PNM began re-balancing the NDT investment portfolio with a target of 85% fixed income (debt) securities. The re-balancing was completed in January 2018 and increases the exposure of the NDT investment portfolio to interest rate risk. The Company is also contemplating decreasing its allocation target beginning in 2018 for liability matching fixed-income securities in the pension trusts from 65% to 50%. Declines in market values could result in increased funding of the trusts, the recognition of losses as impairments for the NDT and mine reclamation trusts, and additional expense for the benefit plans. In addition, a change in GAAP requires that all changes in the fair value of equity securities recorded on the Company's balance sheet be reflected in earnings beginning in 2018, which could result in increased volatility in earnings.

Impairments of goodwill and long-lived assets of PNMR, PNM, and TNMP could adversely affect the Company's business, financial position, liquidity, and results of operations.

The Company annually evaluates recorded goodwill for impairment. See Note 18 and the Critical Accounting Policies and Estimates section of MD&A. Long-lived assets are also assessed whenever indicators of impairment exist. Factors that affect the long-term value of these assets, including treatment by regulators in ratemaking proceedings, as well as other economic and market conditions, could result in impairments. Significant impairments could adversely affect the Company's business, financial position, liquidity, and results of operations.

PNM's PVNGS leases describe certain events, including "Events of Loss" and "Deemed Loss Events", the occurrence of which could require PNM to take ownership of the underlying assets and pay the lessors for the assets.

The "Events of Loss" generally relate to casualties, accidents, and other events at PVNGS, including the occurrence of specified nuclear events, which would severely adversely affect the ability of the operating agent, APS, to operate, and the ability of PNM to earn a return on its interests in PVNGS. The "Deemed Loss Events" consist primarily of legal and regulatory changes (such as issuance by the NRC of specified violation orders, changes in law making the sale and leaseback transactions illegal, or changes in law making the lessors liable for nuclear decommissioning obligations). PNM believes that the probability of such "Events of Loss" or "Deemed Loss Events" occurring is remote for the following reasons: (1) to a large extent, prevention of "Events of Loss" and some "Deemed Loss Events" is within the control of the PVNGS participants through the general PVNGS operational and safety oversight process; and (2) other "Deemed Loss Events" would involve a significant change in current law and policy. PNM is unaware of any proposals pending or being considered for introduction in Congress, or in any state legislative or regulatory body that, if adopted, would cause any of those events. See Note 7.

Governance Factors

Provisions of PNMR's organizational documents, as well as several other statutory and regulatory factors, will limit another party's ability to acquire PNMR and could deprive PNMR's shareholders of the opportunity to receive a takeover premium for shares of PNMR's common stock.

PNMR's restated articles of incorporation and by-laws include a number of provisions that may have the effect of discouraging persons from acquiring large blocks of PNMR's common stock, or delaying or preventing a change in control of PNMR. The material provisions that may have such an effect include:

- Authorization for the Board to issue PNMR's preferred stock in series and to fix rights and preferences of the series (including, among other things, voting rights and preferences with respect to dividends and other matters)
- Advance notice procedures with respect to any proposal other than those adopted or recommended by the Board

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- Provisions specifying that only a majority of the Board, the chairman of the Board, the chief executive officer, or holders of at least one-tenth of all of PNMR's shares entitled to

vote may call a special meeting of stockholders

Under the New Mexico Public Utility Act, NMPRC approval is required for certain transactions that may result in PNMR's change in control or exercise of control, including ownership of 10% or more of PNMR's voting stock. PUCT approval is required for changes to the ownership of TNMP or its parent and certain other transactions relating to TNMP. Certain acquisitions of PNMR's outstanding voting securities also require FERC approval.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

PNMR

The significant properties owned by PNMR include those owned by PNM and TNMP and are disclosed below.

PNM

See Sources of Power in Part I, Item. 1 Business above for information on PNM's owned and leased capacity in electric generating stations. As of December 31, 2017, PNM owned, or jointly owned, 3,200 miles of electric transmission lines, 6,063 miles of distribution overhead lines, 5,828 miles of underground distribution lines (excluding street lighting), and 254 substations. PNM's electric transmission and distribution lines are generally located within easements and rights-of-way on public, private, and Native American lands. PNM owns and leases interests in PVNGS Units 1 and 2 and related property, data processing, communication, office and other equipment, office space, vehicles, and real estate. PNM also owns and leases service and office facilities in Albuquerque and in other areas throughout its service territory. See Note 7 for additional information concerning leases, including PNM's renewal of certain of the PVNGS leases and exercise of its option to purchase the assets underlying certain other leases at the expiration of the original lease terms. See Note 9 for additional information about Valencia.

TNMP

TNMP's facilities consist primarily of transmission and distribution facilities located in its service areas. TNMP also owns and leases vehicles, service facilities, and office locations throughout its service territory. As of December 31, 2017, TNMP owned 978 miles of overhead electric transmission lines, 7,119 miles of overhead distribution lines, 1,241 miles of underground distribution lines, and 116 substations. Substantially all of TNMP's property is pledged to secure its first mortgage bonds. See Note 6.

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ITEM 3. LEGAL PROCEEDINGS

See Note 16 and Note 17 for information related to the following matters for PNMR, PNM, and TNMP, incorporated in this item by reference.

Note 16

- The Clean Air Act – Regional Haze – SJGS
- The Clean Air Act – Regional Haze – Four Corners – Four Corners Federal Agency Lawsuit
- WEG v. OSM NEPA Lawsuit
- Navajo Nation Environmental Issues
- Santa Fe Generating Station
- Coal Supply – Four Corners – Four Corners Coal Supply Arbitration
- Continuous Highwall Mining Royalty Rate
- PVNGS Water Supply Litigation
- San Juan River Adjudication
- Rights-of-Way Matter
- Navajo Nation Allottee Matters
- Sales Tax Audits

Note 17

- PNM – New Mexico General Rate Cases
- PNM – Renewable Portfolio Standard
- PNM – Renewable Energy Rider
- PNM – Energy Efficiency and Load Management
- PNM – Integrated Resource Plans
- PNM – San Juan Generating Station Units 2 and 3 Retirement
- PNM – Advanced Metering Infrastructure Application
- TNMP – Transmission Cost of Service Rates
- TNMP – Order Related to Changes in Federal Income Tax Rates

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

SUPPLEMENTAL ITEM – EXECUTIVE OFFICERS OF PNM RESOURCES, INC.

All officers are elected annually by the Board of PNMR. Executive officers, their ages as of February 23, 2018 and offices held with PNMR for the past five years are as follows:

Name	Age	Office	Initial Effective Date
P. K. Collawn	59	Chairman, President, and Chief Executive Officer	January 2012
C. N. Eldred	64	Executive Vice President and Chief Financial Officer	July 2007
P. V. Apodaca	66	Senior Vice President, General Counsel, and Secretary	January 2010
R. N. Darnell	60	Senior Vice President, Public Policy	January 2012

J. D. Tarry	47	Vice President, Finance and Controller	February 2017
		Vice President, Corporate Controller, and Chief Information Officer	April 2015
		Vice President, Customer Service and Chief Information Officer	May 2012
C. M. Olson	60	Senior Vice President, Utility Operations	February 2018
		Vice President, Utility Operations	December 2016
		Vice President, Generation – PNM	November 2012

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PART II

ITEM 5. MARKET FOR PNMR'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

PNMR's common stock is traded on the New York Stock Exchange (Symbol: PNM). Ranges of sales prices of PNMR's common stock, reported as composite transactions, and dividends declared on the common stock for 2017 and 2016, by quarter, are as follows:

Quarter Ended	Range of Sales Prices		Dividends Declared Per Share
	High	Low	
2017			
March 31	$ 37.60	$ 33.45	$ 0.2425
June 30	40.00	36.30	0.2425
September 30	42.95	37.35	0.2425
December 31	45.50	40.20	0.2650
Fiscal Year	45.50	33.45	0.9925
2016			
March 31	$ 34.07	$ 29.22	$ 0.2200
June 30	35.46	30.62	0.2200
September 30	36.15	31.20	0.2200
December 31	34.53	30.95	0.2425
Fiscal Year	36.15	29.22	0.9025

Dividends on PNMR's common stock are declared by its Board. The timing of the declaration of dividends is dependent on the timing of meetings and other actions of the Board. This has historically resulted in dividends considered to be attributable to the second quarter of each year being declared through actions of the Board during the third quarter of the year. The Board declared dividends on common stock considered to be for the second quarter of $0.22 per share in July 2016 and $0.2425 per share in July 2017, which are reflected as being in the second quarter above. The Board declared dividends on common stock considered to be for the third quarter of $0.22 per share in September 2016 and $0.2425 per share in September 2017, which are reflected as being in the third quarter above. On February 23, 2018, the Board declared a quarterly dividend of $0.2650 per share. PNMR targets a long-term dividend payout ratio of 50% to 60% of ongoing earnings, which is a non-GAAP financial measure that excludes from earnings determined in accordance with GAAP certain non-recurring, infrequent, and other items that are not indicative of fundamental changes in the earnings capacity of the Company's operations. PNMR uses ongoing earnings to evaluate the operations of the Company and to establish goals, including those used for certain aspects of incentive compensation, for management and employees.

On February 20, 2018, there were 8,946 holders of record of PNMR's common stock. All of the outstanding common stock of PNM and TNMP is held by PNMR.

See Note 5 for a discussion on limitations on the payments of dividends and the payment of future dividends, as well as dividends paid by PNM and TNMP.

See Part III, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Preferred Stock

PNM is not aware of any active trading market for its cumulative preferred stock. Quarterly cash dividends were paid on PNM's outstanding cumulative preferred stock at the stated rates during 2017 and 2016. PNMR and TNMP do not have any preferred stock outstanding.

Sales of Unregistered Securities

None.

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ITEM 6. SELECTED FINANCIAL DATA

The selected financial data and comparative operating statistics for PNMR should be read in conjunction with the Consolidated Financial Statements and Notes thereto and MD&A.

PNM RESOURCES, INC. AND SUBSIDIARIES	2017	2016	2015	2014	2013
	(In thousands except per share amounts and ratios)				
Total Operating Revenues	$ 1,445,003	$ 1,362,951	$ 1,439,082	$ 1,435,853	$ 1,387,923
Net Earnings	$ 95,419	$ 131,896	$ 31,078	$ 130,909	$ 115,556

Net Earnings Attributable to PNMR	$ 79,874	$ 116,849	$ 15,640	$ 116,254	$ 100,507
Net Earnings Attributable to PNMR per Common Share					
Basic	$ 1.00	$ 1.47	$ 0.2	$ 1.46	$ 1.26
Diluted	$ 1.00	$ 1.46	$ 0.2	$ 1.45	$ 1.25
Cash Flow Data					
Net cash flows from operating activities	$ 524,462	$ 415,454	$ 386,874	$ 414,876	$ 386,587
Net cash flows from investing activities	$ (466,163)	$ (699,375)	$ (544,528)	$ (485,329)	$ (331,446)
Net cash flows from financing activities	$ (58,847)	$ 242,392	$ 175,431	$ 96,194	$ (61,593)
Total Assets	$ 6,646,103	$ 6,471,080	$ 6,009,328	$ 5,790,237	$ 5,426,858
Long-Term Debt, including current installments	$ 2,437,645	$ 2,392,712	$ 2,091,948	$ 1,962,385	$ 1,730,749
Common Stock Data					
Market price per common share at year end	$ 40.45	$ 34.30	$ 30.57	$ 29.63	$ 24.12
Book value per common share at year end	$ 21.28	$ 21.04	$ 20.78	$ 21.61	$ 21.01
Tangible book value per share at year end	$ 17.79	$ 17.55	$ 17.28	$ 18.12	$ 17.52
Average number of common shares outstanding – diluted	80,141	80,132	80,139	80,279	80,431
Dividends declared per common share	$ 0.9925	$ 0.9025	$ 0.8200	$ 0.7550	$ 0.6800
Capitalization					
PNMR common stockholders' equity	40.9%	41.1%	44.0%	46.6%	49.0%
Preferred stock of subsidiary, without mandatory redemption requirements	0.3	0.3	0.3	0.3	0.3
Long-term debt	58.8	58.6	55.7	53.1	50.7
	100.0%	100.0%	100.0%	100.0%	100.0%

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PNM RESOURCES, INC. AND SUBSIDIARIES
COMPARATIVE OPERATING STATISTICS

	2017	2016	2015	2014	2013
			(In thousands)		
PNM Revenues					
Residential	$ 419,105	$ 395,490	$ 427,958	$ 411,412	$ 411,579
Commercial	408,354	394,150	437,279	428,085	415,621
Industrial	58,851	56,650	75,308	73,002	74,552
Public authority	23,604	23,174	26,202	25,278	25,745
Economy service	30,645	31,121	35,132	39,123	32,909
Transmission	45,932	34,267	33,216	38,284	38,228
Firm-requirements wholesale	4,468	22,497	31,263	38,313	42,370
Other sales for resale [1]	101,897	70,375	63,195	82,508	67,538
Mark-to-market activity	1,317	(1,645)	(5,270)	5,996	293
Other	10,057	9,834	6,912	5,913	7,477
Total PNM Revenues	$ 1,104,230	$ 1,035,913	$ 1,131,195	$ 1,147,914	$ 1,116,312
TNMP Revenues					
Residential	$ 126,587	$ 124,462	$ 120,771	$ 114,826	$ 111,373
Commercial	106,503	103,174	102,956	99,701	95,098
Industrial	18,140	17,427	16,316	15,049	13,084
Other	89,543	81,975	67,844	58,363	52,056
Total TNMP Revenues	$ 340,773	$ 327,038	$ 307,887	$ 287,939	$ 271,611

[1] Includes sales to Tri-State under hazard sharing agreement (Note 17).

PNM MWh Sales					
Residential	3,136,066	3,189,527	3,185,363	3,169,071	3,304,350
Commercial	3,774,417	3,831,295	3,800,472	3,874,292	3,954,774
Industrial	850,914	875,109	957,308	984,130	1,041,160
Public authority	250,500	249,860	246,496	251,187	266,368
Economy service	722,501	805,733	796,430	758,629	719,342
Firm-requirements wholesale	87,600	429,345	444,495	527,597	654,135
Other sales for resale [1]	3,632,137	2,899,322	2,110,947	2,271,480	2,061,851
Total PNM MWh Sales	12,454,135	12,280,191	11,541,511	11,836,386	12,001,980
TNMP MWh Sales					
Residential	2,936,291	2,933,938	2,912,019	2,802,768	2,796,661
Commercial	2,793,263	2,742,366	2,654,102	2,583,664	2,472,979

Industrial	3,202,528	2,976,800	2,804,919	2,708,151	2,576,762
Other	94,767	98,596	100,999	102,118	104,516
Total TNMP MWh Sales	9,026,849	8,751,700	8,472,039	8,196,701	7,950,918

(1) Includes sales to Tri-State under hazard sharing agreement (Note 17).

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PNM RESOURCES, INC. AND SUBSIDIARIES
COMPARATIVE OPERATING STATISTICS

	2017	2016	2015	2014	2013
PNM Customers					
Residential	465,950	462,921	459,353	455,907	453,218
Commercial	56,655	56,357	56,107	55,853	55,447
Industrial	239	247	250	249	251
Economy service	1	1	1	1	1
Other sales for resale	36	36	39	39	34
Other	931	887	908	911	928
Total PNM Customers	523,812	520,449	516,658	512,960	509,879
TNMP Consumers					
Residential	207,788	204,744	202,359	199,963	196,799
Commercial	39,814	39,817	39,014	38,033	37,460
Industrial	82	66	70	70	70
Other	1,948	1,993	2,018	2,044	2,070
Total TNMP Consumers	249,632	246,620	243,461	240,110	236,399
PNM Generation Statistics					
Net Capability – MW, including PPAs (1)	2,580	2,791	2,787	2,707	2,572
Coincidental Peak Demand – MW	1,843	1,908	1,889	1,878	2,008
Average Fuel Cost per MMBTU	$ 1.704	$ 1.821	$ 2.168	$ 2.415	$ 2.237
BTU per KWh of Net Generation	10,396	9,975	10,456	10,422	10,308

(1) 2017 amount is reflective of the shutdown of SJGS Units 2 and 3 in December 2017 and restructured ownership of SJGS Unit 4 as of December 31, 2017

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following Management's Discussion and Analysis of Financial Condition and Results of Operations for PNMR is presented on a combined basis, including certain information applicable to PNM and TNMP. The MD&A for PNM and TNMP is presented as permitted by Form 10-K General Instruction I (2). A reference to a "Note" in this Item 7 refers to the accompanying Notes to Consolidated Financial Statements included in Part II, Item 8, unless otherwise specified. Certain of the tables below may not appear visually accurate due to rounding.

MD&A FOR PNMR

EXECUTIVE SUMMARY

Overview and Strategy

PNMR is a holding company with two regulated utilities serving approximately 773,000 residential, commercial, and industrial customers and end-users of electricity in New Mexico and Texas. PNMR's electric utilities are PNM and TNMP.

Strategic Goals

PNMR is focused on achieving three key strategic goals:

- Earning authorized returns on regulated businesses
- Delivering above industry-average earnings and dividend growth
- Maintaining solid investment grade credit ratings

In conjunction with these goals, PNM and TNMP are dedicated to:

- Maintaining strong employee safety, plant performance, and system reliability
- Delivering a superior customer experience
- Demonstrating environmental stewardship in their business operations

- Supporting the communities in their service territories

Earning Authorized Returns on Regulated Businesses

PNMR's success in accomplishing its strategic goals is highly dependent on two key factors: fair and timely regulatory treatment for its utilities and the utilities' strong operating performance. The Company has multiple strategies to achieve favorable regulatory treatment, all of which have as their foundation a focus on the basics: safety, operational excellence, and customer satisfaction, while engaging stakeholders to build productive relationships. Both PNM and TNMP seek cost recovery for their investments through general rate cases and various rate riders.

Fair and timely rate treatment from regulators is crucial to PNM and TNMP in earning their allowed returns and critical for PNMR to achieve its strategic goals. PNMR believes that earning allowed returns is viewed positively by credit rating agencies and that improvements in the Company's ratings could lower costs to utility customers. Also, earning allowed returns should result in increased earnings for PNMR. Additional information about rate filings is provided in Note 17.

State Regulation

New Mexico 2015 Rate Case – On September 28, 2016, the NMPRC issued an order that authorized PNM to implement an increase in base non-fuel rates of $61.2 million for New Mexico retail customers, effective for bills sent after September 30, 2016. This order was on PNM's application for a general increase in retail electric rates (the "NM 2015 Rate Case") filed in August 2015. PNM's application requested an increase in base non-fuel revenues of $121.5 million based on a future test year ("FTY") beginning October 1, 2015. The primary drivers of the revenue deficiency were infrastructure investments and declines in forecasted energy sales due to successful energy efficiency programs and other economic factors. PNM also proposed changes to rate design to provide fairer pricing across rate classes and better align cost recovery with cost causation.

Following public hearings, the Hearing Examiner in the case issued a recommended decision in August 2016 proposing an increase in non-fuel revenues of $41.3 million (the "August 2016 RD"). The NMPRC's September 26, 2016 order approved many aspects of the August 2016 RD, including the determination that PNM was imprudent in purchasing 64.1 MW of previously leased capacity in PVNGS Unit 2, extending the leases for 114.6 MW of capacity of PVNGS Units 1 and 2, and installing BDT

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equipment on SJGS Units 1 and 4. However, the order also made certain significant modifications to the August 2016 RD. Major components of the difference between the increase in non-fuel revenues approved in the order and PNM's request, include:

- A ROE of 9.575%, compared to the 10.5% requested by PNM
- Inclusion of the January 2016 purchase of the assets underlying three leases of capacity, totaling 64.1 MW, of PVNGS Unit 2 (Note 7) at an initial rate base value of $83.7 million, compared to PNM's request for recovery of the fair market value purchase price of $163.3 million; and disallowance of the recovery of the undepreciated costs of capitalized improvements made during the period the 64.1 MW was being leased by PNM, which costs totaled $43.8 million when the order was issued
- Disallowance of the recovery of any future contributions for PVNGS decommissioning costs related to the 64.1 MW of capacity in PVNGS Unit 2 purchased in January 2016 and the 114.6 MW of the leased capacity in PVNGS Units 1 and 2 that were extended for eight years beginning January 15, 2015 and 2016 (Note 7)
- Disallowance of recovery of the costs associated with converting SJGS Units 1 and 4 to BDT, which is required by the NSR permit for SJGS (Note 16), but allows recovery of avoided operating and maintenance expenses of $0.3 million annually related to BDT; PNM's share of the costs of installing the BDT equipment was $52.3 million, $40.0 million of which PNM requested be included in rate base in the NM 2015 Rate Case
- Disallowance of recovery of $4.5 million of amounts recorded as regulatory assets and deferred charges

The order continued the renewable energy rider and approved certain aspects of PNM's proposals regarding rate design, but did not approve certain other rate design proposals or PNM's request for a revenue decoupling pilot program. The order also proposed changes in the methods of recovering certain costs through PNM's FPPAC and renewable energy rider. The order credited retail customers with 100% of the New Mexico jurisdictional portion of revenues from "refined coal" (a third-party pre-treatment process) at SJGS. The order approved PNM's proposals for revised depreciation rates (with certain exceptions), and the ratemaking treatment of the "prepaid pension asset."

On September 30, 2016, PNM filed a notice of appeal with the NM Supreme Court regarding the order in the NM 2015 Rate Case. On October 26, 2016, PNM filed a statement of issues related to its appeal with the NM Supreme Court, which stated PNM is appealing the NMPRC's determination that PNM was imprudent in the actions taken to purchase the previously leased 64.1 MW of capacity in PVNGS Unit 2, extending the leases for 114.6 MW of capacity of PVNGS Units 1 and 2, and installing BDT equipment on SJGS Units 1 and 4. Specifically, PNM's statement indicated it is appealing the following elements of the NMPRC's order:

- Disallowance of recovery of the full fair market value purchase price of the 64.1 MW of capacity in PVNGS Unit 2 purchased in January 2016
- Disallowance of the recovery of the undepreciated costs of capitalized improvements made during the period the 64.1 MW of capacity was leased by PNM
- Disallowance of recovery of future contributions for PVNGS decommissioning attributable to 64.1 MW of purchased capacity and the 114.6 MW of capacity under the extended leases
- Disallowance of recovery of the costs of converting SJGS Units 1 and 4 to BDT

NEE, NMIEC, and ABCWUA filed notices of cross appeal to PNM's appeal. The issues that are being appealed by the various cross-appellants are:

- The NMPRC allowing PNM to recover the costs of the lease extensions for the 114.6 MW of PVNGS Units 1 and 2 and any of the purchase price for the 64.1 MW in PVNGS Unit 2
- The NMPRC allowing PNM to recover the costs incurred under the new coal supply contract for Four Corners
- The revised method to collect PNM's fuel and purchased power costs under the FPPAC
- The final rate design
- The NMPRC allowing PNM to include the "prepaid pension asset" in rate base

NEE subsequently filed a motion for a partial stay of the order at the NM Supreme Court, which was denied. The NM Supreme Court stated that the court's intent was to request that PNM reimburse ratepayers for any amount overcharged should the cross-appellants prevail on the merits.

On February 17, 2017, PNM filed its Brief in Chief, and pursuant to the court's rules, the briefing schedule was completed on July 21, 2017. Oral argument at the NM Supreme Court was held on October 30, 2017. Although appeals of regulatory actions of the NMPRC have a priority at the NM Supreme Court under New Mexico law, there is no required time frame for the court to act on the appeals.

PNM evaluated the accounting consequences of the order in the NM 2015 Rate Case and the likelihood of being successful on the issues it is appealing in the NM Supreme Court as required under GAAP. The evaluation indicated it is reasonably possible that PNM will be successful on the issues it is appealing. If the NM Supreme Court rules in PNM's favor on some or all of the issues, those issues would be remanded back to the NMPRC for further action. PNM originally estimated that it would take a minimum of 15 months, from the date PNM filed its appeal, for the NM Supreme Court to render a decision and for the NMPRC to take action on any remanded issues. During such time, the rates specified in the order will remain in effect. Accordingly, at September 30, 2016, PNM recorded a pre-tax regulatory disallowance of $11.3 million, representing 15 months of capital cost recovery for the period October 1, 2016 through December 31, 2017 on its investments that the order disallowed, as well as amounts recorded as regulatory assets and deferred charges that the order disallowed and which PNM did not challenge in its appeal. The NM Supreme Court did not render a decision on the case by December 31, 2017, the end of the originally estimated 15 month period. As of December 31, 2017, PNM updated its evaluation of the issues it is appealing in the NM Supreme Court. Although PNM cannot predict the ultimate outcome of this matter, PNM's evaluation continues to indicate it is reasonably possible that PNM will be successful on the issues it is appealing and that it will take a minimum of an additional seven months from December 31, 2017 for the NM Supreme Court to render a decision and for the NMPRC to take action on any remanded issues. On December 31, 2017, PNM recorded an additional pre-tax regulatory disallowance of $3.1 million, representing seven months of capital cost recovery on its investments the order disallowed. Additional losses will be recorded if the estimated time frame for the NM Supreme Court to render a decision and for the NMPRC to take action on any remanded issues is further extended.

PNM continues to believe that the disallowed investments, which are the subject of PNM's appeal, were prudently incurred and that PNM is entitled to full recovery of those investments through the ratemaking process. If PNM's appeal is unsuccessful, PNM would record additional pre-tax losses related to any unsuccessful issues. The December 31, 2017 book values of PNM's investments that the order disallowed, after considering the losses recorded through December 31, 2017, were $75.3 million for the 64.1 MW of purchased capacity in PVNGS Unit 2, $39.1 million for the PVNGS Unit 2 disallowed capital improvements, and $49.4 million for the BDT equipment.

PNM does not believe that the likelihood of the cross-appeals being successful is probable. However, if the NM Supreme Court were to overturn all of the issues subject to the cross-appeals and, upon remand, the NMPRC did not provide any cost recovery of those items, PNM would write-off all of the costs to acquire the assets previously leased under three leases aggregating 64.1 MW of PVNGS Unit 2 capacity, totaling $151.1 million at December 31, 2017 (which amount includes $75.3 million that is the subject of PNM's appeal discussed above) after considering the losses recorded through December 31, 2017. The impacts of not recovering costs for the lease extensions, new coal supply contract for Four Corners, and "prepaid pension asset" in rate base would be recognized in future periods reflecting that rates charged to customers would not recover those costs as they are incurred. The outcomes of the cross-appeals regarding the FPPAC and rate design should not have a financial impact to PNM.

New Mexico 2016 Rate Case – On December 7, 2016, PNM filed an application with the NMPRC for a general increase in retail electric rates (the "NM 2016 Rate Case"). PNM did not include any of the costs disallowed in the NM 2015 Rate Case that are at issue in its pending appeal to the NM Supreme Court. Key aspects of PNM's request in the NM 2016 Rate Case were:

- An increase in base non-fuel revenues of $99.2 million
- Based on a FTY beginning January 1, 2018 (the NMPRC's rules specify that a FTY is a 12 month period beginning up to 13 months after the filing of a rate case application)
- A ROE of 10.125%
- Drivers of revenue deficiency
  - Implementation of the modifications in PNM's resource portfolio, which were previously approved by the NMPRC as part of the SJGS regional haze compliance plan (see below and Note 16)
  - Infrastructure investments, including environmental upgrades at Four Corners
  - Declines in forecasted energy sales due to successful energy efficiency programs and other economic factors
  - Updates in the FERC/retail jurisdictional allocations
- Proposed changes to rate design to establish fair and equitable pricing across rate classes and to better align cost recovery with cost causation
  - Increased customer and demand charges
  - A "lost contribution to fixed cost" mechanism applicable to residential and small commercial customers to address the regulatory disincentive associated with PNM's energy efficiency programs

After NMPRC ordered settlement discussions were held, PNM and representatives of several intervenors reached an agreement on the parameters for a settlement in this proceeding. In May 2017, PNM and thirteen intervenors (the "Signatories") entered into a comprehensive stipulation. On May 12, 2017, the Hearing Examiners issued an order rejecting the stipulation in its then current form and allowing the Signatories to revise the stipulation. On May 23, 2017, the Signatories filed a revised

stipulation that addressed the issues raised by the Hearing Examiners in their order. NEE was the sole party opposing the revised stipulation. The terms of the revised stipulation included:

- A revenue increase totaling $62.3 million, with an initial increase of $32.3 million beginning January 1, 2018 and the remaining increase beginning January 1, 2019
- A ROE of 9.575%
- Full recovery of PNM's investment in SCRs at Four Corners with a debt-only return
- An agreement not to seek to adjust non-fuel base rate changes to be effective prior to January 1, 2020
- An agreement to adjust the January 2019 increase for certain changes in federal corporate tax laws and to true-up PNM's cost of debt
- Returning to customers over a three-year period the benefit of the reduction in the New Mexico corporate income tax rate to the extent attributable to PNM's retail operations
- PNM would withdraw its proposal for a "lost contribution to fixed cost" mechanism with the issue to be addressed in a future docket
- PNM would perform a cost benefit analysis in its 2020 IRP of the impact of a possible early exit from Four Corners in 2024 and 2028

A public hearing on the revised stipulation was held in August 2017. On October 31, 2017, the Hearing Examiners issued a Certification of Stipulation recommending modifications to the revised stipulation that would identify PNM's decision to continue its participation in Four Corners as imprudent, not allow PNM to collect a debt or equity return on $148.1 million of investments in SCRs and other projects at Four Corners, and to temporarily disallow recovery of $36.8 of PNM's projected capital improvements at SJGS. On December 20, 2017, the NMPRC issued an order approving the Certification of Stipulation with certain changes, which included requiring the impacts of changes related to the reduction in the federal corporate income tax rate and PNM's cost of debt be implemented effective January 1, 2018 rather than January 1, 2019 and deferring further consideration regarding the prudency of PNM's decision to continue its participation in Four Corners to a future proceeding.

On December 28, 2017, PNM filed a motion requesting rehearing and asking the NMPRC to vacate their December 20, 2017 order. Several signatories to the revised stipulation filed a separate motion for rehearing asking that the NMPRC approve the revised stipulation without modification. NEE filed a response urging the NMPRC to reject PNM's motion. On January 3, 2018, the NMPRC vacated its December 20, 2017 order and granted the motions for rehearing, which was held on January 10, 2018. The NMPRC issued an order dated January 10, 2018 that approved the Certification of Stipulation with certain changes, which included allowing PNM to recover its $148.1 million of investments in SCR and other projects at Four Corners with a debt-only return (but maintaining the recommended disallowance of an equity return), deferring further consideration regarding the prudency of PNM's decisions to

continue its participation in Four Corners to PNM's next general rate case, requiring the impacts of changes related to the reduction in the federal corporate income tax rate and PNM's cost of debt be implemented in 2018 rather than January 1, 2019, and requiring PNM to reduce its requested $62.3 million increase in non-fuel revenues by $9.1 million.

On January 16, 2018, PNM requested clarifying changes to that order to adjust the $9.1 million reduction to $4.4 million, asserting that $4.7 million of the reduction was duplicative. PNM's request was approved by the NMPRC. After implementation of changes to the federal corporate income tax rate and cost of debt, the order results in a net increase to PNM's non-fuel revenue requirement of $10.3 million. PNM implemented 50% of the approved increase for service rendered, rather than bills rendered, on or after February 1, 2018 and will implement the rest of the increase for service rendered on or after January 1, 2019. GAAP requires PNM to recognize a loss reflecting that it will earn a debt-only return on $148.1 million of investments at Four Corners rather than a full return. Accordingly, PNM recorded a pre-tax regulatory disallowance of $27.9 million as of December 31, 2017.

On February 7, 2018, NEE filed a notice of appeal with the NM Supreme Court asking the court to review the NMPRC's decisions in the NM 2016 Rate Case. The notice does not set forth the basis of the appeal, which, as required by the court's rules, is to be filed by March 9, 2018. PNM cannot predict the outcome of this matter.

Advanced Metering – In September 2011, TNMP began its deployment of advanced meters for homes and businesses across its service area. TNMP completed its mass deployment in 2016 and has installed more than 242,000 advanced meters. As part of the State of Texas' long-term initiative to create an advanced electric grid, installation of advanced meters will ultimately give consumers more data about their energy consumption and help them make more informed decisions. In addition, TNMP has completed installation of a new outage management system that will leverage capabilities of the advanced metering infrastructure to enhance TNMP's responsiveness to outages.

On February 26, 2016, PNM filed an application with the NMPRC requesting approval of a project to replace its existing customer metering equipment with Advanced Metering Infrastructure ("AMI"). The application also asks the NMPRC to authorize the recovery, in future ratemaking proceedings, of the cost of the project, currently estimated to be $95.1 million, as well as to

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approve the recovery of the remaining undepreciated investment in existing metering equipment estimated to be approximately $33 million and the costs of customer education and severance for any affected employees. During a March 2017 hearing, it was identified that the proposed meter contractor may not have complied with certain New Mexico contractor licensing requirements. PNM subsequently filed testimony regarding that matter as ordered by the Hearing Examiner and requested a new procedural schedule to allow it to issue a new RFP for contracting work related to the meter installation and to update its cost-benefit analysis. An additional hearing was held in October 2017. PNM does not intend to proceed with the AMI project unless the NMPRC approves the entire application. PNM cannot predict the outcome of this matter.

PVNGS Unit 3 – Through December 31, 2017, PNM's 134 MW interest in PVNGS Unit 3 was excluded from NMPRC jurisdictional rates. The power generated from that interest was sold into the wholesale market and any earnings or losses were realized by shareholders. As part of compliance with the requirements for BART at SJGS discussed below, the NMPRC approved including PVNGS Unit 3 as a jurisdictional resource in the determination of rates charged to customers in New Mexico beginning in 2018. PVNGS Unit 3 is included as a jurisdictional resource in PNM's NM 2016 Rate Case (Note 17).

Rate Riders and Interim Rate Relief – The PUCT has approved mechanisms that allow TNMP to recover capital invested in transmission and distribution projects without having to file a general rate case. This permits more timely recovery of investments. The PUCT has also approved riders that allow TNMP to recover amounts related to AMS, energy efficiency, third-party transmission costs, and the CTC. The NMPRC has approved PNM recovering fuel costs through the FPPAC, as well as rate riders for renewable energy and energy efficiency that allow for more timely recovery of investments and improve PNM's ability to earn its authorized return.

TNMP General Rate Case – TNMP's last general rate case was filed in 2010 with new rates becoming effective on February 1, 2011. In connection with TNMP's deployment of its AMS, TNMP has committed to file a general rate case no later than September 1, 2018. TNMP currently anticipates filing its general rate case in May 2018 using a 2017 calendar year test period. New rates are anticipated to become effective during January 2019.

FERC Regulation

Rates PNM charges wholesale transmission customers and wholesale generation services customers are subject to traditional rate regulation by FERC. For a number of years, PNM allocated a portion of its generation assets to serve FERC wholesale generation services customers. The low natural gas price environment resulted in market prices for power being substantially lower than what PNM is able to offer wholesale generation customers under the cost of service model that FERC requires PNM to use. As a result of this change in market conditions, PNM had not been earning an adequate return on the assets required to serve wholesale generation contracts. Consequently, PNM decided to stop pursuing wholesale generation contracts. Currently, PNM has no full-requirements wholesale generation customers.

Rates charged to wholesale electric transmission are based on a formula rate mechanism pursuant to which rates for wholesale transmission service are calculated annually in accordance with an approved formula. The formula includes updating cost of service components, including investment in plant and operating expenses, based on information contained in PNM's annual financial report filed with FERC, as well as including projected large transmission capital projects to be placed into service in the following year. The projections included are subject to true-up in the following year formula rate. Certain items, including changes to return on equity and depreciation rates, require a separate filing to be made with FERC before being included in the formula rate.

Navopache Electric Cooperative, Inc. – PNM had a PSA, which contained an expiration date in 2035, to supply power to NEC that was approved by FERC in April 2013. On April 8, 2015, NEC filed a petition for a declaratory order requesting that FERC find that NEC could purchase an unlimited amount of power and energy from third party supplier(s) under the PSA. PNM intervened, requesting that FERC deny NEC's petition. FERC set the matter for a public hearing concerning the parties' intent with regard to certain provisions of the PSA and held the hearing in abeyance to provide time for settlement judge procedures.

On October 29, 2015, PNM and NEC entered into, and filed with FERC, a settlement agreement, which FERC approved in January 2016. Under the agreement, PNM served all of NEC's load through December 31, 2015 at rates that were substantially consistent with those provided under the PSA. In 2016, PNM served all of NEC's load at reduced demand and energy rates from those under the PSA. The PSA terminated on December 31, 2016. In 2017, PNM served 10 MW of NEC's load under a short-term coordination tariff at a rate lower than provided under the PSA, but higher than prices available under short-term market rates at the time of the settlement. In 2017, 2016 and 2015, revenues from NEC were $4.5 million, $20.0 million, and $27.1 million. Although the settlement agreement negatively impacted results of operations in 2017, PNM mitigated these impacts through market sales of power that would have been sold to NEC, reductions in fuel and transmission expenses, and other measures. PNM's NM

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2016 Rate Case discussed above reflects a reallocation of costs among regulatory jurisdictions reflecting the termination of the contract to serve NEC.

Delivering Above Industry-Average Earnings and Dividend Growth

PNMR's strategic goal to deliver above industry-average earnings and dividend growth enables investors to realize the value of their investment in the Company's business. PNMR's current target is 6% earnings growth for the period 2018 through 2021. Earnings growth is based on ongoing earnings, which is a non-GAAP financial measure that excludes from GAAP earnings certain non-recurring, infrequent, and other items that are not indicative of fundamental changes in the earnings capacity of the Company's operations. PNMR uses ongoing earnings to evaluate the operations of the Company and to establish goals, including those used for certain aspects of incentive compensation, for management and employees.

PNMR targets a dividend payout ratio of 50% to 60% of its ongoing earnings. PNMR expects to provide above industry-average dividend growth in the near-term and to manage the payout ratio to meet its long-term target. The Board will continue
to evaluate the dividend on an annual basis, considering sustainability and growth, capital planning, and industry standards. The Board approved the following increases in the indicated annual common stock dividend:

Approval Date	Percent Increase
February 2012	16%
February 2013	14%
December 2013	12%
December 2014	8%
December 2015	10%
December 2016	10%
December 2017	9%

Maintaining Solid Investment Grade Credit Ratings

The Company is committed to maintaining solid investment grade credit ratings in order to reduce the cost of debt financing and to help ensure access to credit markets, when required. See the subheading Liquidity included in the full discussion of Liquidity and Capital Resources below for the specific credit ratings for PNMR, PNM, and TNMP. Currently, all of the credit ratings issued by both Moody's and S&P on the Company's debt are investment grade. In June 2017, Moody's changed the outlook for PNMR and PNM from stable to positive while maintaining a stable outlook for TNMP. In January 2018, S&P changed the outlook for PNMR, PNM, and TNMP from stable to negative.

Business and Strategic Focus

PNMR strives to create enduring value for customers, communities, and shareholders. PNMR's strategy and decision-making are focused on safely providing reliable, affordable, and environmentally responsible power. The Company works closely with customers, stakeholders, legislators, and regulators to ensure that resource plans and infrastructure investments benefit from robust public dialogue and balance the diverse needs of our communities. Equally important is the focus of PNMR's utilities on customer satisfaction and community engagement.

Reliable and Affordable Power

PNMR and its utilities are aware of the important roles they play in enhancing economic vitality in their service territories. Management believes that maintaining strong and modern electric infrastructure is critical to ensuring reliability and supporting economic growth. When contemplating expanding or relocating their operations, businesses consider energy affordability and reliability to be important factors. PNM and TNMP strive to balance service affordability with infrastructure investment to maintain a high level of electric reliability and to deliver a superior customer experience. Investing in PNM's and TNMP's infrastructure is critical to ensuring reliability and meeting future energy needs. Both utilities have long-established records of providing customers with reliable electric service.

Utility Plant and Strategic Investments

Utility Plant Investments – During the 2015 to 2017 period, PNM and TNMP together invested $1,552.0 million in utility plant, including substations, power plants, nuclear fuel, and transmission and distribution systems. PNM completed the 40 MW natural gas-fired La Luz peaking generating station located near Belen, New Mexico in December 2015. PNM also completed installation of SNCR and BDT equipment on SJGS Units 1 and 4 in early 2016 and the addition of 40 MW of PNM-owned solar

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PV facilities in 2015. In addition, on January 15, 2016, PNM completed the $163.3 million acquisition of 64.1 MW of capacity in PVNGS Unit 2 that had previously been leased to PNM.

Strategic Investments – In 2017, PNMR Development and AEP OnSite Partners created NM Renewable Development, LLC ("NMRD") to pursue the acquisition, development, and ownership of renewable energy generation projects, primarily in the state of New Mexico. Abundant renewable resources, large tracts of affordable land, and strong government and community support make New Mexico a favorable location for renewable generation. New Mexico has the 2nd highest technical potential of the 48 contiguous states for utility scale solar photovoltaics as noted in 2015 by the National Renewable Energy Laboratory, while New Mexico is 6th for technical potential for land-based wind. PNMR Development and AEP OnSite Partners each have a 50% ownership interest in NMRD. Through NMRD, PNMR anticipates being able to provide additional renewable generation solutions to customers within and surrounding its regulated jurisdictions through partnering with a subsidiary of one of the United States' largest electric utilities. The formation of this joint venture provides a more efficient use of PNMR's capital to support new renewable investment opportunities while maintaining the necessary capital to support investments required by PNM's regulated jurisdictions. NMRD's current renewable energy capacity under contract is 31.8 MW. This includes 11.8 MW of solar PV facilities currently in operation, consisting of 10 MW required to supply energy to a new data center in PNM's service territory (Note 17) and 1.8 MW to supply energy to Columbus Electric Cooperative located in southwest New Mexico. At December 31, 2017, NMRD also had 20 MW of solar PV facilities under construction, which will be completed in mid-2018 and will also be used to supply the new data center. NMRD is actively exploring opportunities for additional renewable projects. In addition, NMRD will evaluate potential bid opportunities for future renewable projects, including large-scale projects to serve future data center and other customer needs.

Integrated Resource Plan

NMPRC rules require that investor-owned utilities file an IRP every three years. The IRP is required to cover a 20-year planning period and contain an action plan covering the first four years of that period. PNM filed its 2014 IRP on July 1, 2014. The four-year action plan was consistent with the replacement resources identified in PNM's application to retire SJGS Units 2 and 3. PNM indicated that it planned to meet its anticipated energy demand with a combination of additional renewable energy resources, energy efficiency, and natural gas-fired facilities.

PNM filed its 2017 IRP on July 3, 2017. Under the NMPRC's order concerning SJGS' compliance with the BART requirements of the CAA discussed in Note 16, PNM is required to make a filing in 2018 to determine the extent to which SJGS should continue serving PNM's retail customers' needs after June 30, 2022. The 2017 IRP analyzed several scenarios utilizing assumptions that PNM continues service from its SJGS capacity beyond mid-2022 and that PNM retires its capacity after mid-2022. Key findings of the 2017 IRP include:

- Retiring PNM's share of SJGS in 2022 after the expiration of the current operating and coal supply agreements would provide long-term cost savings for PNM's customers

- PNM exiting its ownership interest in Four Corners after its current coal supply agreement expires in 2031 would also provide long-term cost savings for customers
- The best mix of new resources to replace the retired coal generation would include solar energy and flexible natural gas-fired peaking capacity; the mix could include energy storage if the economics support it and wind energy provided additional transmission capacity becomes available
- Significant increases in future wind energy supplies will likely require new transmission capacity to be built from eastern New Mexico to PNM's service territory
- PNM should retain the currently leased capacity in PVNGS, which would avoid replacement with carbon-emitting generation
- PNM should continue to develop and implement energy efficiency and demand management programs
- PNM should assess the costs and benefits of participating in the California Energy Imbalance Market
- PNM should analyze its current Reeves Generating Station to consider possible technology improvements to phase out the older generators and replace them with new, more flexible supplies or energy storage

Several parties filed protests to the 2017 IRP. The issues addressed in the protests include PNM's future interest in SJGS, Four Corners, and PVNGS and the timing of future procurement of renewable resources. The 2017 IRP is not a final determination of PNM's future generation portfolio. Retiring PNM's share of SJGS capacity and exiting Four Corners would require NMPRC approval of abandonment filings, which PNM would make at appropriate times in the future. Likewise, NMPRC approval of new generation resources through CCN filings would be required. PNM cannot predict the ultimate outcome of the 2017 IRP process or whether the NMPRC will approve subsequent filings that would encompass actions to implement the conclusions of the 2017 IRP.

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Environmentally Responsible Power

PNMR has a long-standing record of environmental stewardship. PNM's environmental focus has been in three key areas:

- Developing strategies to meet regional haze rules at the coal-fired SJGS as cost-effectively as possible while providing broad environmental benefits that also demonstrate progress in addressing CO_2 emissions from existing power plants
- Preparing to meet New Mexico's increasing renewable energy requirements as cost-effectively as possible
- Increasing energy efficiency participation

PNMR's Sustainability Portal provides key environmental and sustainability information related to PNM's and TNMP's operations and is available at http://www.pnmresources.com/about-us/sustainability-portal.aspx. The portal also contains a Climate Change Report, which outlines plans to be coal-free by 2031 (subject to regulatory approval). This could enable an 87% reduction in CO_2 emissions in 2040 compared to 2012 levels. This is a significantly greater reduction than that required of New Mexico under EPA's Clean Power Plan.

SJGS

Regional Haze Rule Compliance Plan – In December 2015, PNM received NMPRC approval for the plan to comply with the EPA regional haze rule at SJGS that minimizes the cost impact to customers while still achieving broad environmental benefits. Under the approved plan, the installation of SNCRs on SJGS Units 1 and 4 was completed in early 2016 and Units 2 and 3 were retired in December 2017. The plan provides for similar visibility improvements, but at a lower cost to PNM customers than a previous EPA ruling that would have required the installation of more expensive SCRs on all four units at SJGS. The plan has the added advantage of reducing other emissions in addition to NOx, including SO_2, particulate matter, CO_2, and mercury, as well as reducing water usage. Additional information is contained in Note 16.

Under the key provisions of the order approving the compliance plan, PNM:

- Retired SJGS Units 2 and 3 (PNM's ownership interest was 418 MW) in December 2017 and will recover, over 20 years, 50% ($125.5 million) of their undepreciated net book value at that date and earn a regulated return on those costs
- Acquired an additional 132 MW in SJGS Unit 4 under an approved CCN, with an initial book value of zero plus SNCR costs and whatever portion of BDT costs the NMPRC determines to be reasonable and prudent to be allowed for recovery in rates (an aggregate of $20.7 million) (see New Mexico Rate Cases above and Note 17)
- Was granted a CCN for 134 MW of PVNGS Unit 3 with an initial rate base value equal to the book value as of December 31, 2017 ($154.9 million)
- Acquired 65 MW of SJGS Unit 4 as merchant utility plant, which will not be included in rates charged to retail customers
- Will accelerate recovery of SNCR costs on SJGS Units 1 and 4 so that the costs are fully recovered by July 1, 2022
- Is required to make a NMPRC filing in 2018 to determine the extent that SJGS should continue serving PNM's customers' needs after mid-2022
- Will acquire and retire one MWh of RECs that include a zero-CO_2 emission attribute beginning January 1, 2020 for every MWh produced by 197 MW of coal-fired generation from PNM's ownership share of SJGS (the cost of these RECs would be capped at $7.0 million per year and recovered in rates)
- Did not recover approximately $20 million of increased operations and maintenance expenses and other costs incurred in connection with CAA compliance

At December 31, 2015, PNM recorded pre-tax losses aggregating $165.7 million to reflect the write-off of the 50% of the estimated December 31, 2017 net book value of SJGS Units 2 and 3 that will not be recovered, the other unrecoverable costs, and the increase in the estimated liability recorded for coal mine reclamation resulting from the new coal mine reclamation arrangement entered into in conjunction with the new coal supply agreement ("SJGS CSA"). PNM recorded additional pre-tax losses of $3.7 million in 2016 and reversed previously recorded losses of $4.0 million in 2017 resulting from revised estimates of these items. Additional information about the SJGS CSA is discussed below and in Note 16.

On January 14, 2016, NEE filed a notice of appeal with the NM Supreme Court of the NMPRC's December 2015 order. The NM Supreme Court has taken no action on the appeal and there is no required time frame for the court to act on the appeal. On March 31, 2016, NEE filed a complaint against PNM with the NMPRC regarding the financing provided by NM Capital to facilitate the sale of SJCC. The complaint alleges that PNM failed to comply with its discovery obligation in the SJGS abandonment case and requests the NMPRC investigate whether the financing transactions could adversely affect PNM's ability to provide electric service to its retail customers. PNM responded to the complaint on May 4, 2016. The NMPRC has taken no action on this matter.

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SJGS Ownership Restructuring – In connection with the proposed retirement of SJGS Units 2 and 3, some of the SJGS participants expressed a desire to exit their ownership in the plant. As a result, the SJGS participants negotiated a restructuring of the ownership in SJGS and addressed the obligations of the exiting participants for plant decommissioning, mine reclamation, environmental matters, and certain future operating costs, among other items.

The San Juan Project Restructuring Agreement ("SJGS RA") sets forth the agreement among the SJGS owners regarding ownership restructuring. Key provisions of the SJGS RA

include:

- Capacity acquisition – On December 31, 2017, PNM was to acquire 132 MW and PNMR Development was to acquire 65 MW of the exiting owners' capacity in SJGS Unit 4. PNMR Development assigned the rights and obligations related to the 65 MW to PNM effective on December 31, 2017, to facilitate dispatch of power from that capacity. As ordered by the NMPRC, PNM will treat the 65 MW as merchant utility plant that will be excluded from retail rates. In anticipation of the transfer of ownership, PNM entered into agreements to sell the power from 36 MW of that capacity to a third party at a fixed price for the period January 1, 2018 through June 30, 2022.
- Coal inventory – The SJGS RA also sets forth the terms under which PNM acquired the coal inventory of the exiting SJGS participants as of January 1, 2016 and supplied coal to the exiting participants during the period from January 1, 2016 through December 31, 2017, which arrangement provided economic benefits that were passed on to PNM's customers through the FPPAC.
- Coal supply – The SJGS RA became effective contemporaneously with the effectiveness of the new SJGS CSA. The effectiveness of the new SJGS CSA was dependent on the closing of the purchase of the existing coal mine operation by a new mine operator, which occurred on January 31, 2016. In support of the closing of the mine purchase and to facilitate PNM customer savings, NM Capital, a wholly-owned subsidiary of PNMR, provided funding of $125.0 million to Westmoreland San Juan, LLC ("WSJ"), a ring-fenced, bankruptcy-remote, special-purpose entity that is a subsidiary of Westmoreland Coal Company to finance the purchase price. NM Capital was able to provide the $125.0 million financing to WSJ by first entering into a $125.0 million term loan agreement with a commercial bank. PNMR guarantees NM Capital's obligations to the bank. The Westmoreland Loan matures on February 1, 2021 and had an initial interest rate of 7.25% plus LIBOR, which escalates over time. Such rate is 12.25% plus LIBOR for the period from February 1, 2018 through January 31, 2019. WSJ must pay principal and interest quarterly to NM Capital in accordance with an amortization schedule. As of February 20, 2018, the balance of the Westmoreland Loan was $51.0 million.
- Coal mine reclamation – Under the terms of the SJGS CSA, PNM and the other SJGS owners are obligated to compensate SJCC for all reclamation costs associated with the supply of coal from the San Juan mine. In connection with certain mining permits relating to the operation of the San Juan mine, SJCC is required to post reclamation bonds, which currently aggregate $118.7 million, with the NMMMD. PNMR has arrangements under which a bank has issued $30.3 million in letters of credit to facilitate posting of the required reclamation bonds. See Note 16.

Other SJGS Environmental Matters – In addition to the regional haze rule, SJGS is required to comply with other rules currently being developed or implemented that affect coal-fired generating units, including rules regarding GHG under Section 111(d) of the CAA. Implementation of the Clean Power Plan, which was published by EPA in October 2015, is currently stayed by order of the US Supreme Court pending further proceedings before the DC Circuit. Oral argument was heard by the DC Circuit in September 2016, but the court has taken no action. On March 28, 2017, President Trump issued an Executive Order on Energy Independence. The order sets out two general policies: promote clean and safe development of energy resources, while avoiding regulatory burdens, and ensure electricity is affordable, reliable, safe, secure, and clean. The order rescinds various actions undertaken by the previous administration and directs the EPA Administrator to review and if appropriate suspend, revise, or rescind the Clean Power Plan, as well as other environmental regulations. On October 10, 2017, EPA issued a proposal to repeal the Clean Power Plan based on a legal interpretation of the CAA under which the Clean Power Plan exceeds EPA's statutory authority. EPA published the proposed repeal rule on October 16, 2017 and is accepting public comments until April 26, 2018. In addition, EPA published an advanced NOPR on December 28, 2017 to take comment on whether EPA should adopt a rule to replace the Clean Power Plan and what such a replacement rule might include, for which public comments were due February 26, 2018.

PNM estimates that implementation of the BART plan at SJGS, as well as potentially exiting ownership in the remaining units at SJGS (as well as Four Corners), as discussed above, should provide significant steps for New Mexico to meet its ultimate compliance with Section 111(d) under the Clean Power Plan or any replacement rule. PNM is unable to predict the impact of this rule on its fossil-fueled generation.

Because of environmental upgrades completed in 2009, SJGS has a mercury removal efficiency of 98% and mercury emissions are well below the mercury limit imposed by EPA in the 2011 Mercury and Air Toxics Standards. Major environmental upgrades on each of the four units at SJGS have significantly reduced emissions of NOx, SO_2, particulate matter, and mercury.

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S&P Global Market Intelligence

Between 2006 and 2017, SJGS has reduced NOx emissions by 41%, SO_2 by 70%, particulate matter by 61%, and mercury by 98%.

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Renewable Energy

PNM's renewable procurement strategy includes utility-owned solar capacity, as well as wind and geothermal energy purchased under PPAs. As of December 31, 2017, PNM had 107 MW of utility-owned solar capacity. In addition, PNM purchases power from a customer-owned distributed solar generation program that had an installed capacity of 81.6 MW at December 31, 2017. PNM also owns the 500 KW PNM Prosperity Energy Storage Project, which uses advanced batteries to store solar power and dispatch the energy either during high-use periods or when solar production is limited. The project was one of the first combinations of battery storage and PV energy in the nation and involved extensive research and development of advanced grid concepts. The facility also was the nation's first solar storage facility fully integrated into a utility's power grid. Since 2003, PNM has purchased the output from New Mexico Wind, a 204 MW wind facility, and began purchasing the output of Red Mesa Wind, an existing 102 MW wind energy center, on January 1, 2015. PNM has a 20-year agreement to purchase energy from the Lightning Dock Geothermal facility built near Lordsburg, New Mexico. The geothermal facility, which has a current capacity of 4 MW, began providing power to PNM in January 2014. PNM also purchases RECs as necessary to meet the RPS.

The majority of these renewable resources are key means for PNM to meet the RPS and related regulations that require PNM to achieve prescribed levels of energy sales from renewable sources, if that can be accomplished without exceeding the RCT limit set by the NMPRC. PNM makes renewable procurements consistent with the plans approved by the NMPRC. PNM's 2017 renewable energy procurement plan meets RPS and diversity requirements for 2017 and 2018 using existing resources and does not propose any significant new procurements. The NMPRC approved the plan on November 23, 2016. On June 1, 2017, PNM filed its 2018 renewable energy procurement plan. PNM requested approval to procure an additional 80 GWh in 2019 and 105 GWh in 2020 from a re-powering of New Mexico Wind; approval to procure an additional 55 GWh in 2019 and 77 GWh in 2020 from a re-powering of Lightning Dock Geothermal; approval to procure 50 MW of new solar facilities to be constructed beginning in 2018; continuation of customer REC purchase programs; and other purchases of RECs to ensure annual compliance with the RPS. A public hearing on the application was held in September 2017. On October 17, 2017, the Hearing Examiner issued a recommended decision that PNM's 2018 renewable energy procurement plan be approved by the NMPRC, except for the re-powering of Lightning Dock Geothermal and PNM's request to procure 50 MW of new solar facilities. The Hearing Examiner recommended that the PPA for the output of energy from Lightning Dock Geothermal be terminated effective January 1, 2018. The Hearing Examiner also recommended that PNM be required to issue another all-renewables RFP allowing developers to utilize PNM-owned sites to construct facilities, the output from which facilities would be sold to PNM through PPAs. PNM disagreed with the Hearing Examiner's recommendations and filed exceptions contesting the Hearing Examiner's proposals. On November 15, 2017, the NMPRC issued an order approving PNM's plan and rejecting the Hearing Examiner's recommendations. NMIEC filed an appeal with the NM Supreme Court objecting to the fuel allocation methodology. NEE filed a motion to intervene and cross-appeal objecting to the approval of the 50 MW of new solar facilities. PNM filed a motion to intervene. The NM Supreme Court granted the motions to intervene. NMIEC filed a motion for a partial stay and PNM filed a response opposing the request. A briefing schedule has not been determined. PNM cannot predict the outcome of this matter.

In late 2017, PNM entered into three separate 25-year PPAs to purchase renewable energy and RECs to be used by PNM to supply additional renewable power to Facebook, Inc. These PPAs are subject to NMPRC approval and PNM made a filing requesting approval on January 17, 2018 (Note 17). These PPAs include the purchase of the power and RECs from a 50 MW wind project to be operational at December 31, 2018, a 166 MW wind project to be operational in November 2020, and a 50 MW solar project to be operational in December 2021.

PNM will continue to procure renewable resources while balancing the impact to customers' electricity costs in order to meet New Mexico's escalating RPS requirements.

Energy Efficiency

Energy efficiency also plays a significant role in helping to keep customers' electricity costs low while meeting their energy needs. PNM's and TNMP's energy efficiency and load management portfolios continue to achieve robust results. In 2017, annual energy saved as a result of PNM's portfolio of energy efficiency programs was approximately 78 GWh. This is equivalent to the annual consumption of approximately 11,500 homes in PNM's service territory. PNM's load management and annual energy efficiency programs also help lower peak demand requirements. TNMP's energy efficiency programs in 2017 resulted in energy savings totaling an estimated 21 GWh. This is equivalent to the annual consumption of approximately 2,300 homes in TNMP's service territory. In April 2016 and again in April 2017, TNMP was recognized by Energy Star for TNMP's successful energy efficiency efforts. TNMP received the "Partner of the Year Energy Efficiency Delivery Award" for its High-Performance Homes Program.

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Water Conservation and Solid Waste Reduction

PNM continues its efforts to reduce the amount of fresh water used to make electricity (about 20% more efficient than in 2007). Continued growth in PNM's fleet of solar and wind energy sources, energy efficiency programs, and innovative uses of gray water and air-cooling technology have contributed to this reduction. Water usage will continue to decline as PNM substitutes less fresh-water-intensive generation resources to replace SJGS Units 2 and 3 starting in 2018, when water consumption at that plant will be reduced by around 50%. Focusing on responsible stewardship of New Mexico's scarce water resources improves PNM's water-resilience in the face of persistent drought and ever-increasing demands for water to spur the growth of New Mexico's economy. In addition to the above areas of focus, the Company is working to reduce the amount of solid waste going to landfills through increased recycling and reduction of waste. In 2017, 18 of the Company's 23 facilities met the solid waste diversion goal of a 60% diversion rate, while recycling at least the same number of waste streams as 2016. The Company expects to continue to do well in this area in the future.

Customer, Stakeholder, and Community Engagement

The Company strives to deliver a superior customer experience. Through outreach, collaboration, and various community-oriented programs, the Company has a demonstrated commitment to build productive relationships with stakeholders, including customers, community partners, regulators, intervenors, legislators, and shareholders. PNM continues to focus its efforts to enhance the customer experience through customer service improvements, including billing and payment options, strategic customer engagement, and improved communications. These efforts are supported by market research to understand the varying needs of customers, identifying and establishing valued services and programs, and proactively communicating and engaging with customers at regional and community levels.

The Company has leveraged a number of communications channels and strategic content to better serve and engage its many stakeholders. PNM's website, www.pnm.com, provides the details of major regulatory filings, including general rate requests, as well as the background on PNM's efforts to maintain reliability, keep prices affordable, and protect the environment. In May 2017, a chat function was added to PNM's website to allow customers options when communicating with its customer service representatives and an online management system was launched to expedite solar interconnection applications from retail customers. The website continues to be a resource for the facts about PNM's operations and community support efforts, including plans for building a sustainable energy future for New Mexico. In September 2016, PNMR launched a dedicated sustainability portal on its corporate website www.pnmresources.com to provide additional information regarding the Company's environmental and other sustainability efforts. The site provides the key corporate governance and sustainability information related to the operations of PNM and TNMP. In January 2018, PNM added a Climate Change Report to this portal. The information is presented under four main headings: Environment, Social, Economic, and Governance.

With reliability being the primary role of a transmission and distribution service provider in Texas' deregulated market, TNMP continues to focus on keeping end-users updated about interruptions and to encourage customer preparation when severe weather is forecasted. In August 2017, Hurricane Harvey made landfall in the gulf coast region and TNMP worked diligently to restore power safely and efficiently for affected customers. In addition, PNMR made donations to support relief and restoration efforts in the gulf coast region. TNMP employees who were impacted by Hurricane Harvey were provided emergency crisis funds supported by the PNM Resources Foundation and other employee donations.

Local relationships and one-on-one communications remain two of the most valuable ways both PNM and TNMP connect with their stakeholders. Both companies maintain long-standing relationships with governmental representatives and key customers to ensure that these stakeholders are updated on company investments and initiatives. Key stakeholders also have dedicated Company contacts that support their important service needs.

PNMR has a long tradition of supporting the communities it serves in New Mexico and Texas. The Company demonstrates its core value of caring through the PNM Resources Foundation, corporate giving, widespread employee volunteerism, and PNM's low-income assistance programs. In addition to the extensive engagement both PNM and TNMP have with nonprofit organizations in their communities, the PNM Resources Foundation provides more than $1 million in grant funding each year across New Mexico and Texas. These grants help nonprofits collaborate more efficiently and support community projects such as providing software coding camps to underserved youths, funding murals in neighborhoods, and by providing employee matching and volunteer grants. In 2017, "A New Century of Service" grants, which celebrate PNM's 100th anniversary, funded 62 community projects to build a better future for local communities. In December 2017, PNM announced an additional $1.0 million in donations to the PNM Resources Foundation to support future economic and educational programs in New Mexico.

PNM provides funds to support nonprofits in New Mexico focused in the areas of economic development, education, and the environment. One of PNM's most important outreach programs is tailored for low-income customers. In 2017, PNM hosted

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44 community events throughout its service territory to connect low-income customers with nonprofit community service providers offering support and help with such needs as water and gas utility bills, food, clothing, medical programs, and services for seniors. Additionally, through its Good Neighbor Fund, PNM provided $0.5 million of assistance with electric bills to 3,804 families in 2017 and offered financial literacy training to further support customers.

Volunteerism is an important facet of the PNMR culture. In 2017, more than 800 PNM and TNMP employees and retirees contributed approximately 10,800 volunteer hours serving their local communities. Company volunteers also actively participate on nonprofit boards, in educational, economic, and environmental forums, as well as safety seminars. PNMR employees are, in large part, responsible for the success of the Company's customer, stakeholder, and community outreach.

Economic Factors

PNM – In 2017 and 2016, PNM experienced decreases in weather-normalized retail load of 0.9% and 0.7%, reflecting a continued sluggish economy in New Mexico. However, economic conditions in Albuquerque appear to have stabilized. The Albuquerque metro area is showing employment growth, but continues to be lower than the national average. Also, some of the previously announced successful economic development efforts, such as the selection of a site within PNM's New Mexico service territory for a data center by Facebook, Inc., appear to have started their hiring process. There also have been some expansions of existing businesses, particularly in healthcare, education, and professional services. The economy in New Mexico continues to have mixed indicators and experience softness.

TNMP – In 2017 and 2016, TNMP experienced increases in volumetric weather normalized retail load of 1.2% and 3.0%. Most of TNMP's industrial and larger commercial customers are billed based on their peak demand. Demand-based load, excluding retail transmission customers, increased 4.0% and 2.4% in 2017 and 2016. The Texas economy continues to grow, primarily due to its diverse base, which offsets some of the impacts of Hurricane Harvey. Because TNMP's service territory is geographically dispersed and was largely on the edges of the storm, a smaller percentage of customers were impacted by the hurricane as compared to some other utilities. The relocation of some national and global corporate headquarters to the Dallas-Fort Worth area has led to growth in commercial customers and also contributes to growth in residential and small business customers. TNMP continues to add new transmission customers in its West Texas service territory where oil and gas production continues to grow.

Results of Operations

Net earnings attributable to PNMR were $79.9 million, or $1.00 per diluted share in the year ended December 31, 2017 compared to $116.8 million, or $1.46 per diluted share in 2016. Among other things, earnings in 2017 benefited from additional revenues due to the rate increase approved in the NM 2015 Rate Case at PNM, higher revenues under FERC formula transmission rates and new transmission customers at PNM, rate increases and increased load at TNMP, lower plant maintenance costs at PNM, higher gains on available-for-sale securities, higher AFUDC due to higher levels of construction expenditures at PNM, and excess tax benefits related to stock compensation recognized under a new accounting standard (Note 13). These increases were more than offset by decreased load at PNM, milder weather at PNM and TNMP, lower revenue from NEC at PNM, greater regulatory disallowances at PNM, increased depreciation and property taxes due to increased plant in service at PNM and TNMP and higher depreciation rates approved in PNM's NM 2015 Rate Case, and lower interest income on the Westmoreland Loan and from the IRS, as well as the additional income taxes resulting from the reduction in the federal corporate income tax rate (Note 11) and increased pre-tax earnings. Additional information on factors impacting results of operation for each segment is discussed under Results of Operations below.

Liquidity and Capital Resources

PNMR and PNM have revolving credit facilities that expire in October 2022. The PNMR and PNM facilities have capacities of $300.0 million and $400.0 million through October 2020 and $290.0 million and $360.0 million from November 2020 through October 2022. Both facilities provide for short-term borrowings and letters of credit. In addition, PNM has a $40.0 million revolving credit facility, which expires in December 2022, with banks having a significant presence in New Mexico and TNMP has a $75.0 million revolving credit facility, which expires in September 2022. Total availability for PNMR on a consolidated basis was $522.3 million at February 20, 2018. On February 26, 2018, PNMR Development entered into a $24.5 million revolving credit facility that matures on February 25, 2019. The Company utilizes these credit facilities and cash flows from operations to provide funds for both construction and operational expenditures. PNMR also has intercompany loan agreements with each of its subsidiaries.

PNMR projects that its consolidated capital requirements, consisting of construction expenditures and dividends, will total $3,136.8 million for 2018-2022. The construction expenditures include estimated amounts for environmental upgrades at Four Corners, 50 MW of new solar facilities included in PNM's 2018 renewable energy procurement plan, an anticipated expansion of

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S&P Global Market Intelligence

PNM's transmission system, and the initial costs of replacement resources related to the potential shutdown of SJGS Units 1 and 4 in 2022.

In July 2017, PNM entered into the PNM 2017 Senior Unsecured Note Agreement, under which $450.0 million of the PNM 2018 SUNs are to be issued in 2018 and the proceeds will be used to repay $450.0 million of currently outstanding Senior Unsecured Notes on their maturity dates in 2018. After considering these financings, PNMR has consolidated maturities and repayments of short-term and long-term debt aggregating $357.3 million in the period from January 1, 2018 through December 31, 2018. Furthermore the $200.0 million PNM 2017 Term Loan Agreement matures in January 2019 and TNMP has $172.3 million of first mortgage bonds that are due in April 2019. In addition to internal cash generation, the Company anticipates that it will be necessary to obtain additional long-term financing in the form of debt refinancing, new debt issuances, and/or new equity in order to fund its capital requirements during the 2018-2022 period. The Company currently believes that its internal cash generation, existing credit arrangements, and access to public and private capital markets will provide sufficient resources to meet the Company's capital requirements for the next twelve months. The Company is in compliance with its debt covenants.

RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the Consolidated Financial Statements and Notes thereto. Trends and contingencies of a material nature are discussed to the extent known. Also, refer to Disclosure Regarding Forward Looking Statements in Part I, Item 1 and to Risk Factors in Part I, Item 1A.

A summary of net earnings attributable to PNMR is as follows:

	Year Ended December 31,			Change	
	2017	2016	2015	2017/2016	2016/2015
	(In millions, except per share amounts)				
Net earnings attributable to PNMR	$ 79.9	$ 116.8	$ 15.6	$ (37.0)	$ 101.2
Average diluted common and common equivalent shares	80.1	80.1	80.1	—	—
Net earnings attributable to PNMR per diluted share	$ 1.00	$ 1.46	$ 0.20	$ (0.46)	$ 1.26

The components of the changes in net earnings attributable to PNMR by segment are:

	Change	
	2017/2016	2016/2015
	(In millions)	
PNM	$ (5.0)	$ 92.7
TNMP	(6.1)	(0.3)

Corporate and Other	(25.9)	8.9
Net change	$ (37.0)	$ 101.2

Information regarding the factors impacting PNMR's operating results by segment are set forth below.

Segment Information

The following discussion is based on the segment methodology that PNMR's management uses for making operating decisions and assessing performance of its various business activities. See Note 2 for more information on PNMR's operating segments.

PNM

PNM defines utility margin as electric operating revenues less cost of energy, which consists primarily of fuel and purchase power costs. PNM believes that utility margin provides a more meaningful basis for evaluating operations than electric operating revenues since substantially all fuel and purchase power costs are offset in revenues as those costs are passed through to customers

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under PNM's FPPAC. Utility margin is not a financial measure required to be presented under GAAP and is considered a non-GAAP measure.

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The following table summarizes the operating results for PNM:

	Year Ended December 31,			Change	
	2017	2016	2015	2017/2016	2016/2015
			(In millions)		
Electric operating revenues	$ 1,104.2	$ 1,035.9	$ 1,131.2	$ 68.3	$ (95.3)
Cost of energy	321.7	299.7	391.1	22.0	(91.4)
Utility margin	782.6	736.2	740.1	46.4	(3.9)
Operating expenses	423.0	414.7	591.0	8.3	(176.3)
Depreciation and amortization	147.0	133.4	115.7	13.6	17.7
Operating income	212.5	188.1	33.4	24.4	154.7
Other income (deductions)	39.1	32.2	33.5	6.9	(1.3)
Interest charges	(82.7)	(87.5)	(80.0)	4.8	(7.5)
Segment earnings (loss) before income taxes	169.0	132.9	(13.1)	36.1	146.0
Income (taxes) benefit	(81.6)	(40.9)	12.8	(40.7)	(53.7)
Valencia non-controlling interest	(15.0)	(14.5)	(14.9)	(0.5)	0.4
Preferred stock dividend requirements	(0.5)	(0.5)	(0.5)	—	—
Segment earnings (loss)	$ 71.9	$ 76.9	$ (15.8)	$ (5.0)	$ 92.7

The following table shows GWh sales, including the impacts of weather, by customer class and average number of customers:

	Year Ended December 31,			Change	
	2017	2016	2015	2017/2016	2016/2015
			(Gigawatt hours, except customers)		
Residential	3,136.1	3,189.5	3,185.4	(53.4)	4.1
Commercial	3,774.4	3,831.3	3,800.5	(56.9)	30.8
Industrial	850.9	875.1	957.3	(24.2)	(82.2)
Public authority	250.5	249.9	246.5	0.6	3.4
Economy service [1]	722.5	805.7	796.4	(83.2)	9.3
Firm-requirements wholesale [2]	87.6	429.3	444.5	(341.7)	(15.2)
Other sales for resale [3]	3,632.1	2,899.3	2,110.9	732.8	788.4
	12,454.1	12,280.2	11,541.5	174.0	738.6
Average retail customer (thousands)	522.0	518.6	514.9	3.4	3.7

(1) PNM purchases energy for a major customer on the customer's behalf and delivers the energy to the customer's location through PNM's transmission system. PNM charges the customer for the cost of the energy as a direct pass through to the customer with no impact to PNM's utility margin so there is only a minor impact in utility margin resulting from providing ancillary services.

(2) Decrease in 2017 reflects reduced sales to NEC (Note 17) and loss of other firm-requirements wholesale customers.

(3) Increases in 2017 and 2016 include the hazard sharing agreement with Tri-State (Note 17). Increase is also due to more power available for off-system sales, primarily related to SJGS and Four Corners, as well as power that was previously sold to NEC and other firm-requirements wholesale customers. Substantially all of the margin from off-system sales is returned to customers through the FPPAC.

Operating Results – 2017 Compared to 2016

The following table summarizes the significant changes to utility margin:

	Year Ended December 31, 2017 Change
Utility margin:	(In millions)
Rate relief – Additional revenue due to rate increase approved by the NMPRC on September 28, 2016 and certain fuel costs being passed through the FPPAC	$ 51.9
Customer usage/load – PNM's weather normalized retail KWh sales decreased 0.9%, due to decreased sales to residential, commercial, and industrial customers	(5.9)
Weather – Milder weather; heating degree days were 8.9% lower, partially offset by higher cooling degree days of 2.0%	(3.8)
Leap Year – Decrease in revenue due to additional day in 2016	(1.6)
Transmission – Higher revenues under formula transmission rates and the addition of new customers	12.1
Wholesale contracts – Primarily due to NEC (Note 17)	(7.8)
Unregulated margin – Higher hedged prices for PVNGS Unit 3 power sales	3.9
Rate riders – Includes renewable energy and energy efficiency riders, which are partially offset in operating expenses, depreciation and amortization, and interest charges	(1.9)
Net unrealized economic hedges – Losses related to hedges of NEC power sales, partially offset by gains related to hedges of PVNGS	(1.3)
Other	0.8
Net Change	$ 46.4

The following tables summarize the primary drivers for operating expenses, depreciation and amortization, other income (deductions), interest charges, and income taxes:

	Year Ended December 31, 2017 Change
Operating expenses:	(In millions)
2017 regulatory disallowance due to the NMPRC's January 17, 2018 order in PNM's NM 2016 Rate Case (Note 17)	$ 27.9
Regulatory disallowances due to the NMPRC's September 28, 2016 order in PNM's NM 2015 Rate Case (Note 17)	(8.1)
Regulatory disallowances due to change in estimated write-offs associated with the SJGS BART determination and ownership restructuring (Note 16)	(7.8)
Lower plant maintenance costs at SJGS, Four Corners, and PVNGS, partially offset by increased costs at gas-fired plants	(3.8)
Implementation of process improvement initiatives in 2016 associated with reducing future costs	(3.7)
Lower employee related expenses and outside consulting costs	(3.4)
Lower rent expense associated with PVNGS leases (Note 7)	(0.9)
Higher capitalized administrative and general expenses due to higher construction spending	(1.7)
Higher allocated corporate depreciation, primarily related to computer software	5.4
Training costs associated with new software implementation	1.1
Contribution to the PNM Resources Foundation	1.0
Higher property taxes due to increased utility plant in service	0.9
Higher environmental expenses	0.5
Other	0.9
Net Change	$ 8.3

Depreciation and amortization:

Higher depreciation rates approved by the NMPRC in PNM's 2015 NM Rate Case, including the impacts of impairments (Note 17)	$ 6.1

Increased utility plant in service	6.8
Other	0.7
Net Change	$ 13.6

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	Year Ended December 31, 2017 Change
Other income (deductions):	(In millions)
Higher gains on available-for-sale securities in the NDT and coal mine reclamation trusts	$ 7.6
Higher equity AFUDC, primarily due to increased levels of construction expenditures	4.5
Interest income from third party transmission service provider due to FERC ruling	1.0
Lower income from “refined coal” (a third-party pre-treatment process); income is now passed through to customers as ordered in PNM’s NM 2015 Rate Case	(3.8)
2016 interest income from IRS, net of related expenses (Note 11)	(2.9)
Other	0.5
Net Change	$ 6.9
Interest charges:	
Lower interest on $146.0 million of PCRBs refinanced in September 2016	$ 2.6
Lower interest on $57.0 million of PCRBs refinanced in June 2017	0.6
Lower short term debt borrowings	0.8
Higher debt AFUDC as a result of higher construction spending	1.0
Other	(0.2)
Net Change	$ 4.8
Income taxes:	
Increase due to higher segment earnings before income taxes	$ (13.8)
Impacts of increase in equity AFUDC	1.7
Regulatory recovery of prior year impairments of state net operating loss carryforwards due to NMPRC orders in PNM rate cases (Note 17) (net of amortization)	0.3
Impacts of phased-in reduction in New Mexico corporate income tax rates	2.0
Decrease due to excess tax benefits related to stock compensation awards (Note 13)	1.7
Impairments of state NOL carryforwards	(0.9)
Impact of change in federal corporate income tax rate	(29.6)
Other impairments and valuation allowances	(2.1)
Net Change	$ (40.7)

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Operating Results – 2016 Compared to 2015

The following table summarizes the significant changes to utility margin:

	Year Ended December 31, 2016 Change
Utility margin:	(In millions)
Customer usage/load – PNM’s weather normalized retail KWh sales decreased 0.7%; decreased industrial sales were offset by increases in residential and commercial customer sales, who pay a higher price per KWh	$ 1.1
Rate relief – Additional revenue due to the rate increase and certain fuel costs being passed through the FPPAC	19.6
Weather – Milder weather; heating degree days were lower by 3.9% and cooling	

degree days were lower by 2.2% in 2016	(0.9)
Transmission – Higher revenues under formula transmission rates and lower cost of third party transmission	3.2
Wholesale contracts – Primarily lower revenues from NEC (Note 17)	(5.8)
Unregulated margin – Lower market prices for PVNGS Unit 3 sales	(12.1)
Rate riders – Includes renewable energy and energy efficiency riders, which are partially offset in operating expenses, depreciation and amortization, and interest charges	(6.3)
Net unrealized economic hedges – Primarily related to hedges of PVNGS Unit 3 power sales	3.6
Settlements – 2015 refunds under FERC tariff for gas transportation agreement and SPS settlement (Note 16)	(5.4)
Other	(0.9)
Net Change	$ (3.9)

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The following tables summarize the primary drivers for operating expenses, depreciation and amortization, other income (deductions), interest charges, and income taxes:

	Year Ended December 31, 2016 Change
Operating expenses:	(In millions)
Regulatory disallowance due to the NMPRC's September 28, 2016 order in PNM's NM 2015 Rate Case (Note 17)	$ 11.3
Regulatory disallowances associated with the SJGS BART determination and ownership restructuring (Note 16)	(162.0)
2015 regulatory disallowance of rate case expenses resulting from the NMPRC dismissal of the 2014 general rate case	(1.5)
Lower rent expense associated with PVNGS leases (Note 7)	(21.7)
Lower rent expense due to the termination of the EIP lease on April 1, 2015	(0.7)
Lower plant maintenance costs at SJGS and gas-fired plants, partially offset by increased costs at Four Corners plant	(8.5)
Higher labor, pension, benefits, and OPEB costs	6.6
Implementation of process improvement initiatives associated with reducing future costs	3.7
Higher property taxes due to increases in utility plant in service	2.3
Higher costs associated with rate riders, which are offset in utility margin	1.8
Lower environmental expenses	(1.0)
2015 costs associated with exploring alternative fuel supply for SJGS	(2.2)
Other	(4.4)
Net Change	$ (176.3)
Depreciation and amortization:	
Purchase of assets underlying PVNGS Unit 2 leases (Note 7)	$ 4.8
Higher depreciation rates approved in the NM 2015 Rate Case	3.3
Other additions to utility plant in service, including PNM-owned solar PV facilities and environmental upgrades at SJGS	9.6
Net Change	$ 17.7
Other income (deductions):	
Higher gains on available-for-sale securities in the NDT and coal mine reclamation trusts	$ 3.5
Interest income from IRS, net of expenses (Note 11)	2.9
Sale of substations and associated transmission facilities in 2015	(1.1)
Higher interest income and lower trust expenses related to available-for-sale securities in the NDT and coal mine reclamation trusts	1.5
Lower equity AFUDC as a result of lower construction spending	(6.3)
Lower income from refined coal (a third-party pre-treatment process at SJGS), due to the decision in the NM 2015 Rate Case directing that such income be passed through to customers	(1.0)
Other	(0.8)
Net Change	$ (1.3)

	Year Ended December 31, 2016 Change
Interest charges:	(In millions)
Issuance of $250.0 million of long-term debt on August 11, 2015	$ (5.5)
Lower debt AFUDC as a result of lower construction spending	(2.2)
Other	0.2
Net Change	$ (7.5)
Income taxes:	
Increase due to higher segment earnings before income taxes	$ (57.1)
Impacts of decrease in equity AFUDC	(2.4)
Impacts of phased-in reduction in New Mexico corporate income tax rates	(1.3)
Reversal of deferred income tax items related to the BART determination for SJGS in 2015	1.8
Allowed regulatory recovery of 2014 impairment of state net operating loss carryforward (net of amortization)	1.9
Impairments of state net operating loss carryforwards in 2015	3.6
Other	(0.2)
Net Change	$ (53.7)

TNMP

TNMP defines utility margin as electric operating revenues less cost of energy, which consists of costs charged by third-party transmission providers. TNMP believes that utility margin provides a more meaningful basis for evaluating operations than electric operating revenues since all third-party transmission costs are passed on to customers through a transmission cost recovery factor. Utility margin is not a financial measure required to be presented under GAAP and is considered a non-GAAP measure.

The following table summarizes the operating results for TNMP:

	Year Ended December 31,			Change	
	2017	2016	2015	2017/2016	2016/2015
			(In millions)		
Electric operating revenues	$ 340.8	$ 327.0	$ 307.9	$ 13.8	$ 19.1
Cost of energy	85.8	80.9	73.5	4.9	7.4
Utility margin	255.0	246.2	234.4	8.8	11.8
Operating expenses	98.2	93.4	88.1	4.8	5.3
Depreciation and amortization	63.1	61.1	56.3	2.0	4.8
Operating income	93.6	91.6	90.0	2.0	1.6
Other income (deductions)	3.6	3.2	3.7	0.4	(0.5)
Interest charges	(30.1)	(29.3)	(27.7)	(0.8)	(1.6)
Segment earnings before income taxes	67.1	65.5	66.1	1.6	(0.6)
Income (taxes)	(31.5)	(23.8)	(24.1)	(7.7)	0.3
Segment earnings	$ 35.6	$ 41.7	$ 42.0	$ (6.1)	$ (0.3)

The following table shows total GWh sales, including the impacts of weather, by retail tariff consumer class and average number of consumers:

	Year Ended December 31,			Percentage Change	
	2017	2016	2015	2017/2016	2016/2015
Volumetric load [1] (GWh)					
Residential	2,936.6	2,933.9	2,912.0	0.1 %	0.8 %
Commercial and other	34.0	42.4	49.3	(19.8)%	(14.0)%
Total volumetric load	2,970.6	2,976.3	2,961.3	(0.2)%	0.5 %
Demand-based load [2] (MW)	16,599.5	15,564.8	14,781.3	6.6 %	5.3 %
Average retail consumers (thousands) [3]	248.3	245.3	241.6	1.2 %	1.5 %

(1) Volumetric load consumers are billed on KWh usage.

(2) Demand-based load includes consumers billed on a monthly KW peak and also includes retail transmission customers that are primarily billed under rate riders.

(3) TNMP provides transmission and distribution services to REPs that provide electric service to customers in TNMP's service territories. The number of consumers above represents the customers of these REPs. Under TECA, consumers in Texas have the ability to choose any REP to provide energy.

Operating results – 2017 compared to 2016

The following table summarizes the significant changes to utility margin:

	Year Ended December 31, 2017 Change
Utility margin:	(In millions)
Rate relief – Transmission cost of service rate increases in March and September of 2017 and 2016	$ 6.7
Retail customer usage/load – Weather normalized retail KWh sales increased 1.2%, primarily related to the residential class; the average number of retail consumers increased 1.2%	0.6
Demand based customer usage/load – Higher demand-based revenues for large commercial and industrial retail consumers; billed demand, excluding retail transmission customers, increased 4.0%	2.5
Wholesale transmission load – Increased coincidental peak load for third-party transmission customers	1.3
Rate riders – Impacts of rate riders, including the AMS surcharge, CTC surcharge, energy efficiency rider, and transmission cost recovery factor, which are partially offset in operating expenses, depreciation and amortization, and interest charges	(1.4)
Weather – Milder weather in 2017; heating degree days were 13.1% lower	(0.8)
Other	(0.1)
Net Change	$ 8.8

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The following tables summarize the primary drivers for operating expenses, depreciation and amortization, other income (deductions), interest charges, and income taxes:

	Year Ended December 31, 2017 Change
Operating expenses:	(In millions)
Higher allocated corporate depreciation, primarily related to computer software	$ 1.9
Higher outside consulting costs, including vegetation management	2.8
Higher property taxes due to increased utility plant in service	1.4
Higher employee related expenses	0.4
Training costs associated with new software implementation	0.4
Higher capitalized administrative and general expenses due to higher construction spending in 2017	(1.3)
2016 lease abandonment costs associated with building consolidation efforts	(1.0)
Other	0.2
Net Change	$ 4.8

Depreciation and amortization:

Increased utility plant in service	$ 3.0
Reduced CTC amortization and AMS depreciation	(1.0)
Net Change	$ 2.0

Other income (deductions):

Higher CIAC	$ 0.2
2016 interest income from IRS, net of related expenses (Note 11)	(0.3)
Other	0.5
Net Change	$ 0.4

Interest charges:

Increase due to the issuance of $60.0 million of long-term debt in February 2016	$ (0.2)
Increase due to the issuance of $60.0 million of long-term debt in August 2017	(0.7)
Higher debt AFUDC	0.3
Other	(0.2)

Net Change	$ (0.8)

Income taxes:

Increase due to higher segment earnings before income taxes	$ (0.5)
Decrease due to excess tax benefits related to stock compensation awards (Note 13)	0.6
Impact of change in federal corporate income tax rate	(7.9)
Other	0.1
Net Change	$ (7.7)

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Operating Results – 2016 *compared to 2015*

The following table summarizes the significant changes to utility margin:

	Year Ended December 31, 2016 Change
Utility margin:	(In millions)
Rate relief – Transmission cost of service rate increases in March and September of 2016 and 2015 (See Note 17)	$ 4.5
Customer usage/load – 3.0% increase in weather normalized retail KWh sales, primarily related to the residential and commercial classes; higher demand-based revenues for large commercial and industrial retail customers; and increased wholesale transmission load in 2016; the average number of retail customers increased 1.5%	5.7
Rate riders – Impacts of rate riders, including the AMS surcharge, CTC surcharge, energy efficiency rider, and transmission cost recovery factor, which are partially offset in operating expenses, depreciation and amortization, and interest charges	3.3
Weather – Milder weather in 2016; heating degree days were 19.6% lower and cooling degree days were 1.3% higher compared to 2015	(1.8)
Energy efficiency program – Higher incentive bonus in 2016	0.1
Net Change	$ 11.8

The following tables summarize the primary drivers for operating expenses, depreciation and amortization, other income (deductions), interest charges, and income taxes:

	Year Ended December 31, 2016 Change
Operating expenses:	(In millions)
Higher property taxes due to increases in utility plant in service and higher assessed values	$ 1.2
Lease abandonment costs associated with building consolidation efforts	1.0
Higher pension and benefit expense	0.9
Higher rate rider related costs, which are offset in utility margin	0.8
Higher labor	0.8
Other	0.6
Net Change	$ 5.3

Depreciation and amortization:

Increase due to AMS deployment and CTC amortization	$ 2.0
Increase due to increases in utility plant in service	2.8
Net Change	$ 4.8

Other income (deductions):

Decrease primarily due to lower CIAC, partially offset by higher equity AFUDC and interest income from IRS (Note 17)	$ (0.5)

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	Year Ended December 31, 2016 Change
Interest charges:	(In millions)
Increase primarily due to the issuance of $60.0 million of long-term debt on February 10, 2016, partially offset by debt AFUDC	$ (1.6)
Income taxes:	
Decrease primarily due to lower segment earnings before income taxes	$ 0.3

Corporate and Other

The table below summarizes the operating results for Corporate and Other:

	Year Ended December 31,			Change	
	2017	2016	2015	2017/2016	2016/2015
			(In millions)		
Total revenues	$ —	$ —	$ —	$ —	$ —
Cost of energy	—	—	—	—	—
Utility margin	—	—	—	—	—
Operating expenses	(22.1)	(12.8)	(14.9)	(9.3)	2.1
Depreciation and amortization	21.8	14.5	13.9	7.3	0.6
Operating income (loss)	0.4	(1.7)	0.9	2.1	(2.6)
Other income (deductions)	4.2	10.4	(0.6)	(6.2)	11.0
Interest charges	(14.8)	(11.8)	(7.2)	(3.0)	(4.6)
Segment earnings (loss) before income taxes	(10.3)	(3.2)	(6.9)	(7.1)	3.7
Income (taxes) benefit	(17.3)	1.5	(3.7)	(18.8)	5.2
Segment earnings (loss)	$ (27.6)	$ (1.7)	$ (10.6)	$ (25.9)	$ 8.9

Corporate and Other operating expenses shown above are net of amounts allocated to PNM and TNMP under shared services agreements. The amounts allocated include certain expenses shown as depreciation and amortization and other income (deductions) in the table above. The change in depreciation expense primarily relates to increased corporate depreciation rates and computer software. Substantially all depreciation and amortization expense is offset in operating expenses as a result of allocation of these costs to other business segments.

Operating results – 2017 compared to 2016

The following tables summarize the primary drivers for other income (deductions), interest charges, and income taxes:

	Year ended December 31, 2017 Change
Other income (deductions):	(In millions)
Decrease in interest income on the Westmoreland Loan (Note 16)	$ (3.7)
2016 interest income from IRS, net of related expenses (Note 11)	(0.8)
Increase in donations, including the PNM Resources Foundation	(1.5)
Other	(0.2)
Net Change	$ (6.2)

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	Year ended December 31, 2017 Change
Interest charges:	(In millions)
Issuance of the $100.0 million 2016 Two-Year Term Loan in December 2016	$ (2.0)
Issuance of the $100.0 million 2016 One-Year Term Loan in December 2016	(1.9)
Higher short term borrowings and interest rates	(2.4)
Repayment of a $150.0 million PNMR term loan in December 2016	2.0
Decrease in interest expense on the BTMU Loan Agreement (Note 6)	1.2
Other	0.1
Net Change	$ (3.0)
Income taxes:	
Increase in benefit due to change in segment (earnings) loss before income taxes	$ 2.7

Impact of change in federal corporate income tax rate	(20.0)
Other impairments and valuation allowances	(1.1)
Other	(0.4)
Net Change	$ (18.8)

Operating Results – 2016 compared to 2015

The following tables summarize the primary drivers for other income (deductions), interest charges, and income taxes:

	Year ended December 31, 2016 Change
Other income (deductions):	(In millions)
Interest income on the $125.0 million Westmoreland Loan (Note 16) beginning February 1, 2016	$ 11.3
Losses recorded in 2015 on items included in other investments related to a former PNMR subsidiary that ceased operations in 2008	1.1
Interest income from IRS, net of related expenses (Note 11)	0.8
PNMR Development's share of the fee resulting from the ownership restructuring of SJGS recorded at December 31, 2015 (Note 16)	(3.1)
Other	0.9
Net Change	$ 11.0

Interest charges:	
Issuance of the $125.0 million BTMU Term Loan Agreement on February 1, 2016 (Note 6)	$ (4.6)
Issuance of the $150.0 million PNMR 2015 Term Loan Agreement on March 9, 2015	(1.5)
Maturity of $118.8 million of long-term debt on May 15, 2015	4.3
Higher short term borrowings	(2.6)
Other	(0.2)
Net Change	$ (4.6)

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	Year ended December 31, 2016 Change
Income taxes:	(In millions)
Reduction in benefit due to change in segment earnings (loss) before income taxes	$ (1.4)
Impairment of wind energy production tax credits recorded in 2015	3.1
Impairment of state net operating loss recorded in 2015	1.7
Impairment of charitable contributions carry forward recorded in 2015	2.0
Other	(0.2)
Net Change	$ 5.2

LIQUIDITY AND CAPITAL RESOURCES

Statements of Cash Flows

The information concerning PNMR's cash flows is summarized as follows:

	Year Ended December 31,			Change	
	2017	2016	2015	2017/2016	2016/2015
			(In millions)		
Net cash flows from:					
Operating activities	$ 524.5	$ 415.5	$ 386.9	$ 109.0	$ 28.6
Investing activities	(466.2)	(699.4)	(544.5)	233.2	(154.9)
Financing activities	(58.8)	242.4	175.4	(301.2)	67.0
Net change in cash and cash equivalents	$ (0.5)	$ (41.5)	$ 17.8	$ 41.0	$ (59.3)

Cash Flows from Operating Activities

Changes in PNMR's cash flow from operating activities result from net earnings, adjusted for items impacting earnings that do not provide or use cash. See Results of Operations above. Certain changes in assets and liabilities resulting from normal operations, including the effects of the seasonal nature of the Company's operations, also impact operating cash

flows.

Cash Flows from Investing Activities

The changes in PNMR's cash flows from investing activities relate primarily to changes in utility plant additions. Cash flows from investing activities also include activity related to the Westmoreland Loan and NMRD. Major components of PNMR's cash inflows and (outflows) from investing activities are shown below:

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	Year Ended December 31,			Change	
	2017	2016	2015	2017/2016	2016/2015
Cash (Outflows) for Utility Plant Additions			(In millions)		
PNM:					
Generation	$ (74.4)	$ (84.3)	$ (193.6)	$ 9.9	$ 109.3
Transmission and distribution	(173.4)	(127.2)	(182.0)	(46.2)	54.8
Purchase of previously leased capacity in PVNGS Unit 2	—	(163.3)	—	163.3	(163.3)
Four Corners SCRs	(34.9)	(40.9)	—	6.0	(40.9)
Nuclear fuel	(26.4)	(29.8)	(29.2)	3.4	(0.6)
	(309.1)	(445.5)	(404.8)	136.4	(40.7)
TNMP:					
Transmission	(60.7)	(71.5)	(49.7)	10.8	(21.8)
Distribution	(83.5)	(39.4)	(58.7)	(44.1)	19.3
AMS	(1.3)	(11.6)	(16.2)	10.3	4.6
	(145.5)	(122.5)	(124.6)	(23.0)	2.1
Corporate and Other:					
Computer hardware and software	(19.9)	(31.0)	(21.0)	11.1	(10.0)
PNMR Development utility plant additions	(25.9)	(1.1)	(8.2)	(24.8)	7.1
	(45.8)	(32.1)	(29.2)	(13.7)	(2.9)
	$ (500.4)	$ (600.1)	$ (558.6)	$ 99.7	$ (41.5)
Cash Inflows (Outflows) on the Westmoreland Loan					
Loan origination	$ —	$ (122.3)	$ —	$ 122.3	$ (122.3)
Principal payments	38.4	30.0	—	8.4	30.0
	$ 38.4	$ (92.3)	$ —	$ 130.7	$ (92.3)
Cash Inflows (Outflows) Related to NMRD					
Investments in NMRD	$ (4.1)	$ —	$ —	$ (4.1)	$ —
Disbursements from NMRD	12.4	$ —	—	12.4	—
	$ 8.3	$ —	$ —	$ 8.3	$ —

Cash Flow from Financing Activities

The changes in PNMR's cash flows from financing activities include:

- In 2015, PNMR borrowed $150.0 million under the PNMR 2015 Term Loan Agreement and repaid $118.8 million of 9.25% Senior Unsecured Notes with the proceeds; PNMR also increased its borrowings under the PNMR Term Loan Agreement from $100.0 million to $150.0 million
- In 2015, PNM issued $250.0 million aggregate principal amount of its 3.850% Senior Unsecured Notes and repaid a $175.0 million term loan with the proceeds; PNM also drew the remaining capacity of $25.0 million under the $125.0 million PNM Multi-draw Term Loan
- In 2016, PNMR borrowed $100.0 million under the PNMR One-Year Term Loan (included in short-term borrowings) and $100.0 million under the PNMR Two-Year Loan and repaid the PNMR Term Loan Agreement with the proceeds
- In 2016, PNM borrowed $175.0 million under the PNM 2016 Term Loan Agreement and repaid the PNM Multi-draw Term Loan with the proceeds
- NM Capital received net proceeds of $122.5 million under the $125.0 million BTMU Term Loan Agreement in 2016 and utilized the proceeds to provide funds for the Westmoreland Loan; in accordance with the BTMU Term Loan Agreement, NM Capital made principal payments of $42.1 million in 2017 and $32.8 million in 2016
- In 2017, PNM borrowed $200.0 million under the PNM 2017 Term Loan Agreement and repaid the PNM 2016 Term Loan Agreement with the proceeds
- PNM successfully remarketed PCRBs of $57.0 million in 2017, $146.0 million in 2016, and $39.3 million in 2015
- TNMP issued $60.0 million of 3.22% first mortgage bonds in 2017 and $60.0 million of 3.53% first mortgage bonds in 2016

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- Short-term borrowings increased $18.3 million in 2017 compared to an increase of $86.5 million in 2016 and an increase of $95.0 million in 2015, resulting in a net decrease in cash flows from financing activities of $68.2 million in 2017 and $8.5 million in 2016
- In 2017, PNM had net repayments of amounts received under transmission interconnection arrangements of $9.4 million compared to net amounts received in 2016 of $4.3 million and net amounts repaid of $2.3 million in 2015

Financing Activities

See Note 6 for additional information concerning the Company's financing activities. PNM must obtain NMPRC approval for any financing transaction having a maturity of more than 18 months. In addition, PNM files its annual short-term financing plan with the NMPRC. The Company's ability to access the credit and capital markets at a reasonable cost is largely dependent upon its:

- Ability to earn a fair return on equity
- Results of operations
- Ability to obtain required regulatory approvals
- Conditions in the financial markets
- Credit ratings

Each of the Company's revolving credit facilities and term loans contains a single financial covenant, which requires the maintenance of debt-to-capital ratios of less than or equal to 65%, and generally include customary covenants, events of default, cross default provisions, and change of control provisions. The Company is in compliance with its debt covenants.

As discussed in Note 16, NM Capital, a wholly-owned subsidiary of PNMR, entered into the $125.0 million BTMU Term Loan Agreement with The Bank of Tokyo-Mitsubishi UFJ, Ltd. ("BTMU"), as lender and administrative agent. The BTMU Term Loan Agreement has a maturity of February 1, 2021 and bears interest at a rate based on LIBOR plus a customary spread, which aggregated 4.13% at December 31, 2017. The principal balance outstanding under the BTMU Term Loan Agreement was $50.1 million at December 31, 2017 and $45.1 million at February 20, 2018. PNMR, as parent company of NM Capital, has guaranteed NM Capital's obligations to BTMU. NM Capital utilized the proceeds of the BTMU Term Loan Agreement to provide funding for the $125.0 million Westmoreland Loan (Note 16) to a ring-fenced, bankruptcy-remote, special-purpose entity, which is a subsidiary of Westmoreland, to finance Westmoreland's purchase of SJCC.

On October 21, 2016, PNMR entered into letter of credit arrangements with JPMorgan Chase Bank, N.A. (the "JPM LOC Facility") under which letters of credit aggregating $30.3 million were issued to facilitate the posting of reclamation bonds, which SJCC is required to post in connection with permits relating to the operation of the San Juan mine (Note 16).

At January 1, 2017, PNM had $37.0 million of outstanding PCRBs, which have a final maturity of June 1, 2040, and $20.0 million of outstanding PCRBs, which have a final maturity of June 1, 2042. These PCRBs were subject to mandatory tender for remarketing on June 1, 2017 and were successfully remarketed on that date. Both series are now subject to mandatory tender for remarketing on June 1, 2022.

On June 14, 2017, TNMP entered into an agreement, which provided that TNMP would issue $60.0 million aggregate principal amount of 3.22% first mortgage bonds on or about August 25, 2017. TNMP issued the 2017 Series A Bonds on August 24, 2017 and used the proceeds to reduce short-term and intercompany debt and for general corporate purposes.

On July 20, 2017, PNM entered into the $200.0 million PNM 2017 Term Loan Agreement, which bears interest at a variable rate and must be repaid on or before January 18, 2019. PNM used the proceeds of the PNM 2017 Term Loan Agreement to prepay the $175.0 million PNM 2016 Term Loan Agreement, which was to mature on November 17, 2017, and to reduce short-term borrowings.

On July 28, 2017, PNM entered into the PNM 2017 Senior Unsecured Note Agreement with institutional investors for the sale of $450.0 million aggregate principal amount of eight series of Senior Unsecured Notes (the "PNM 2018 SUNs") offered in private placement transactions. PNM has agreed to issue $350.0 million of the PNM 2018 SUNs (at fixed annual interest rates ranging from 3.15% to 4.50% for terms between 5 and 30 years) on or about May 15, 2018 and $100.0 million of the PNM 2018 SUNs (at fixed annual interest rates of 3.78% and 4.60% for terms of 10 and 30 years) on or about August 1, 2018. The issuances of the PNM 2018 SUNs are subject to the satisfaction of customary conditions. PNM will use the gross proceeds from the PNM 2018 SUNs to pay $350.0 million of PNM's 7.95% Senior Unsecured Notes that mature on May 15, 2018 and $100.0 million of PNM's 7.50% Senior Unsecured Notes that mature on August 1, 2018.

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On December 21, 2016, PNMR entered into two term loan agreements: (1) the $100.0 million PNMR 2016 One-Year Term Loan that was to mature on December 21, 2017; and (2) the $100.0 million PNMR 2016 Two-Year Term Loan that matures on December 21, 2018. The proceeds of the term loans were used to repay the $150.0 million twelve-month PNMR Term Loan Agreement and to reduce borrowings under the PNMR Revolving Credit Facility. On December 15, 2017, PNMR amended the PNMR 2016 One-Year Term Loan to extend the maturity date to December 14, 2018.

At December 31, 2017, variable interest rates were 2.34% for the PNMR 2015 Term Loan Agreement, 2.32% for the PNMR 2016 One-Year Term Loan (as extended), 2.32% for the PNMR 2016 Two-Year Term Loan, and 2.29% for the PNM 2017 Term Loan Agreement.

PNMR has a hedging agreement whereby it effectively established a fixed interest rate of 1.927%, subject to change if there is a change in PNMR's credit rating, for borrowings under the $150.0 million PNMR 2015 Term Loan Agreement for the period from January 11, 2016 through its maturity on March 9, 2018. In 2017, PNMR entered into three separate four-year hedging agreements whereby it effectively established fixed interest rates of 1.926%, 1.823%, and 1.629%, plus customary spreads over LIBOR, subject to change if there is a change in PNMR's credit rating, for three separate tranches, each of $50.0 million, of its variable rate debt. The Finance Committee of the Board has authorized management to enter into additional transactions to hedge against exposure to changes in interest rates on its variable rate debt of up to an additional notional amount of $150.0 million.

Capital Requirements

PNMR's total capital requirements consist of construction expenditures and cash dividend requirements for PNMR common stock and PNM preferred stock. Key activities in PNMR's current construction program include:

- Upgrading generation resources, including expenditures for compliance with environmental requirements and for renewable energy resources
- Expanding the electric transmission and distribution systems
- Purchasing nuclear fuel

Projected capital requirements for 2018-2022 are:

	2018	2019-2022	Total
		(In millions)	
Construction expenditures	$ 500.2	$ 2,211.9	$ 2,712.1
Dividends on PNMR common stock	84.4	337.7	422.1
Dividends on PNM preferred stock	0.5	2.1	2.6
Total capital requirements	$ 585.1	$ 2,551.7	$ 3,136.8

The construction expenditure estimates are under continuing review and subject to ongoing adjustment, as well as to Board review and approval. The construction expenditures above include environmental upgrades of $7.9 million at Four Corners, $72.8 million for 50 MW of new solar facilities included in PNM's 2018 renewable energy procurement plan, approximately $170 million for an anticipated expansion of PNM's transmission system, and approximately $100 million in 2021 and $300 million in 2022 for the costs of replacement resources related to the potential shutdown of SJGS Units 1 and 4 in 2022. See Note 17. Expenditures for the expansion of PNM's transmission system and SJGS replacement resources are subject to obtaining necessary approvals of the NMPRC. PNM will be required to file CCN applications with the NMPRC to obtain those approvals. Expenditures for environmental upgrades are estimated to be $7.9 million in 2018. See Note 16 and Commitments and Contractual Obligations below. The ability of PNMR to pay dividends on its common stock is dependent upon the ability of PNM and TNMP to be able to pay dividends to PNMR. Note 5 describes regulatory and contractual restrictions on the payment of dividends by PNM and TNMP.

During the year ended December 31, 2017, PNMR met its capital requirements and construction expenditures through cash generated from operations, as well as its liquidity arrangements and the borrowings discussed in Financing Activities above.

In addition to the capital requirements for construction expenditures and dividends, the Company has long-term debt and term loans that must be paid or refinanced at maturity. The $150.0 million PNMR 2015 Term Loan Agreement matures on March 9, 2018, the $100.0 million PNM 2016 One-Year Term Loan (as extended) matures on December 14, 2018, and the $100 million PNM 2016 Two-Year Term Loan matures on December 21, 2018. Also, $350.0 million of PNM Senior Unsecured Notes mature on May 15, 2018 and $100.0 million of PNM Senior Unsecured Notes mature on August 1, 2018. As described above, PNM entered into the PNM 2017 Senior Unsecured Note Agreement on July 28, 2017. Proceeds from the $450.0 million of the PNM 2018 SUNs to be issued under that agreement will be used to repay the senior unsecured notes that mature on May 15, 2018 and

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August 1, 2018. The BTMU Term Loan Agreement requires that NM Capital utilize all amounts, less taxes and fees, it receives under the Westmoreland Loan to repay the BTMU Term Loan Agreement. Based on scheduled payments on the Westmoreland Loan, NM Capital estimates it will make principal payments of $10.6 million on the BTMU Term Loan Agreement in the year ended December 31, 2018, including $5.0 million paid on February 1, 2018. Note 6 contains additional information about the maturities of long-term debt. PNMR and PNM anticipate that funds to repay these long-term debt maturities and term loans will come from entering into new arrangements similar to the existing agreements, borrowing under their revolving credit facilities, issuance of new long-term debt in the public or private capital markets, or a combination of these sources. The Company has from time to time refinanced or repurchased portions of its outstanding debt before scheduled maturity. Depending on market conditions, the Company may refinance other debt issuances or make additional debt repurchases in the future.

Liquidity

PNMR's liquidity arrangements include the PNMR Revolving Credit Facility, the PNM Revolving Credit Facility, and the TNMP Revolving Credit Facility. Currently, the PNMR Revolving Credit Facility has a financing capacity of $300.0 million, the PNM Revolving Credit Facility has a financing capacity of $400.0 million, and the TNMP Revolving Credit Facility has a financing capacity of $75.0 million. PNMR and PNM entered into agreements to extend the maturity of the PNMR Revolving Credit Facility and the PNM Revolving Credit Facility to October 31, 2022. However, one lender, whose current commitment is $10.0 million under the PNMR Revolving Credit Facility and $40.0 million under the PNM Revolving Credit Facility, did not agree to extend its commitment beyond October 31, 2020. Unless one or more of the other current lenders or a new lender assumes the commitments of the non-extending lender, the financing capacities will be reduced to $290.0 million for the PNMR Revolving Credit Facility and $360.0 million for the PNM Revolving Credit Facility from November 1, 2020 through October 31, 2022. On September 25, 2017, the TNMP Revolving Credit Facility was amended and restated to extend its maturity from September 18, 2018 to September 23, 2022. PNM had the $50.0 million PNM 2014 New Mexico Credit Facility with banks having a significant presence in New Mexico that was scheduled to expire on January 8, 2018. On December 12, 2017, PNM entered into the PNM 2017 New Mexico Credit Facility, a similar $40.0 million unsecured revolving credit facility to replace the PNM 2014 New Mexico Credit Facility. The PNM 2017 New Mexico Credit Facility expires on December 12, 2022. The Company believes the terms and conditions of these facilities are consistent with those of other investment grade revolving credit facilities in the utility industry. The Company expects that it will be able to extend or replace these credit facilities under similar terms and conditions prior to their expirations.

The revolving credit facilities and the PNM 2017 New Mexico Credit Facility provide short-term borrowing capacity. The revolving credit facilities also allow letters of credit to be issued. Letters of credit reduce the available capacity under the facilities. The Company utilizes these credit facilities and cash flows from operations to provide funds for both construction and operational expenditures. The Company's business is seasonal with more revenues and cash flows from operations being generated in the summer months. In general, the Company relies on the credit facilities to be the initial funding source for construction expenditures. Accordingly, borrowings under the facilities may increase over time. Depending on market and other conditions, the Company will periodically sell long-term debt and use the proceeds to reduce the borrowings under the credit facilities. Information regarding the range of borrowings for each facility is as follows:

	Three Months Ended December 31, 2017		Year Ended December 31					
			2017		2016		2015	
Range of Borrowings	Low	High	Low	High	Low	High	Low	High
			(In millions)					
PNM:								
PNM Revolving Credit Facility	$ —	$ 65.0	$ —	$ 65.0	$ —	$ 135.0	$ —	$ 48.4
PNM New Mexico facilities [1]	—	—	—	26.0	—	50.0	—	20.0
TNMP Revolving Credit Facility	—	23.8	—	53.0	—	70.0	—	64.0
PNMR Revolving Credit Facility	117.7	194.7	111.8	235.3	40.0	179.5	—	45.3

[1] Includes both the PNM 2014 New Mexico Credit Facility and the PNM 2017 New Mexico Credit Facility

At December 31, 2017, the average interest rates were 2.76% for the PNMR Revolving Credit Facility and 2.59% for the PNM Revolving Credit Facility. There were no borrowings outstanding under the PNM 2017 New Mexico Facility or the TNMP Revolving Credit Facility at December 31, 2017.

The Company currently believes that its capital requirements for at least the next twelve months can be met through internal cash generation, existing, extended, or new credit arrangements, and access to public and private capital markets. The Company anticipates that it will be necessary to obtain additional long-term financing to fund its capital requirements during the 2018-2022

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period. This could include new debt and/or equity issuances. The Company currently anticipates utilizing a three-year at-the-market equity issuance program to raise equity beginning in

2020 to partially fund capital requirements. This at-the-market program should provide a flexible, efficient, and low-cost way to issue equity as needed. The Company also expects to issue new debt periodically to fund capital investments. To cover the difference in the amounts and timing of internal cash generation and cash requirements, the Company intends to use short-term borrowings under its current and future liquidity arrangements. However, if difficult market conditions return, the Company may not be able to access the capital markets or renew credit facilities when they expire. Should that occur, the Company would seek to improve cash flows by reducing capital expenditures and exploring other available alternatives. Also, PNM could consider seeking authorization for the issuance of first mortgage bonds to improve access to the capital markets.

PNMR currently has no senior unsecured notes outstanding. On June 22, 2015, Moody's assigned an issuer rating of Baa3 to PNMR, upgraded the issuer rating of TNMP to A3 from Baa1, upgraded the senior secured debt rating of TNMP to A1 from A2, and changed the outlook for PNMR, PNM, and TNMP to stable from positive. On December 21, 2015, S&P raised by one notch the issuer credit ratings for PNMR, PNM, and TNMP and the debt ratings for PNM and TNMP, with a stable outlook. In June 2017, Moody's changed the outlook for PNMR and PNM from stable to positive while maintaining a stable outlook for TNMP. On January 16, 2018, S&P changed the outlook for PNMR, PNM, and TNMP from stable to negative while affirming the ratings set forth below for all the entities. As of February 20, 2018, ratings on the Company's securities were as follows:

	PNMR	PNM	TNMP
S&P			
Issuer rating	BBB+	BBB+	BBB+
Senior secured debt	*	*	A
Senior unsecured debt	*	BBB+	*
Preferred stock	*	BBB-	*
Moody's			
Issuer rating	Baa3	Baa2	A3
Senior secured debt	*	*	A1
Senior unsecured debt	*	Baa2	*
* Not applicable			

Currently, all of the credit ratings issued by both Moody's and S&P on the Company's debt are investment grade. However, the ultimate outcomes from PNM's NM 2015 Rate Case and NM 2016 Rate Case, including the pending appeals before the NM Supreme Court, as discussed in Note 17, could affect both the outlook and credit ratings. Investors are cautioned that a security rating is not a recommendation to buy, sell, or hold securities, that each rating is subject to revision or withdrawal at any time by the rating organization, and that each rating should be evaluated independently of any other rating.

A summary of liquidity arrangements as of February 20, 2018 is as follows:

	PNMR Separate	PNM Separate	TNMP Separate	PNMR Consolidated
		(In millions)		
Financing capacity:				
Revolving credit facility	$ 300.0	$ 400.0	$ 75.0	$ 775.0
PNM 2017 New Mexico Credit Facility	—	40.0	—	40.0
Total financing capacity	$ 300.0	$ 440.0	$ 75.0	$ 815.0
Amounts outstanding as of February 20, 2018:				
Revolving credit facility	$ 182.4	$ 57.4	$ 23.9	$ 263.7
PNM 2017 New Mexico Credit Facility	—	20.0	—	20.0
Letters of credit	6.4	2.5	0.1	9.0
Total short-term debt and letters of credit	188.8	79.9	24.0	292.7
Remaining availability as of February 20, 2018	$ 111.2	$ 360.1	$ 51.0	$ 522.3
Invested cash as of February 20, 2018	$ 0.9	$ —	$ —	$ 0.9

In addition to the above, PNMR had $30.3 million of letters of credit outstanding under the JPM LOC Facility. The above table excludes intercompany debt. As of February 20, 2018, PNM and TNMP had no intercompany borrowings from PNMR.

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The remaining availability under the revolving credit facilities at any point in time varies based on a number of factors, including the timing of collections of accounts receivables and payments for construction and operating expenditures.

On February 26, 2018, PNMR Development entered into a $24.5 million revolving credit facility that matures on February 25, 2019. The facility bears interest at a variable rate and contains terms similar to the PNMR Revolving Credit Facility. PNMR has guaranteed the obligations of PNMR Development under the facility. PNMR Development anticipates using the facility to finance its participation in NMRD (Note 1).

PNMR can offer new shares of common stock through the PNM Resources Direct Plan under a SEC shelf registration statement that expires in August 2018. PNM has a shelf registration statement for up to $475.0 million of Senior Unsecured Notes that expires in May 2020.

Off-Balance Sheet Arrangements

PNMR's off-balance sheet arrangements include PNM's operating leases for portions of PVNGS Units 1 and 2 and, until April 1, 2015, the EIP transmission line. These arrangements help ensure PNM the availability of lower-cost generation needed to serve customers.

In 1985 and 1986, PNM consummated sale and leaseback transactions for its interest in PVNGS Units 1 and 2. The original purpose of the sale-leaseback financing was to lower revenue requirements and to levelize the ratemaking impact of PVNGS being placed in-service. The lease payments reflected lower capital costs as the equity investors were able to capitalize the investment with greater leverage than PNM and because the sale transferred tax benefits that PNM could not fully utilize. Under traditional ratemaking, the capital costs of ownership of a major rate base addition, such as a nuclear plant, are front-end loaded with higher revenue requirements in the initial years that decline over the life of the plant as depreciation occurs. By contrast, the revenue requirements for lease payments are level over the lease term. The leases, which were scheduled to expire in 2015 and 2016, contained options to renew the leases at a fixed price or to purchase the property for fair market value.

As discussed in Note 7, PNM and the lessors under each of the PVNGS Unit 1 leases entered into amendments to those leases that extended the leases through January 15, 2023 from their original expiration on January 15, 2015. In addition, PNM entered into an amendment with the lessor under one of the PVNGS Unit 2 leases that extended that lease through January 15, 2024 from its original expiration on January 15, 2016. PNM entered into agreements with the lessors under the other three PVNGS Unit 2 leases under which PNM exercised its option to purchase the assets underlying the leases at the agreed to fair market values aggregating $163.3 million at the expiration of the leases on January 15, 2016. The semiannual renewal payments aggregate $8.3 million under the PVNGS Unit 1 leases and are $0.8 million for the one renewed PVNGS Unit 2 lease. See Sources of Power in Part I, Item 1 and Note 7 for additional information.

The future lease payments for the PVNGS leases are shown below.

	PVNGS Units 1&2
	(In thousands)
2018	$ 18,139
2019	18,139
2020	18,139
2021	18,139
2022	18,139
Thereafter	10,705
Total	$ 101,400

For reasons similar to the PVNGS sale and leaseback transactions, PNM built the EIP transmission line and sold it in sale and leaseback transactions in 1985. Prior to April 1, 2015, PNM owned 60% and operated the other 40% of the EIP line under the terms of a lease agreement. The lease, which contained fixed-rate and fair market value renewal options and a fair market value purchase option, expired on April 1, 2015. PNM exercised its option to purchase the leased assets at expiration of the lease at the agreed to fair market value of $7.7 million. See Note 7.

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Commitments and Contractual Obligations

The following table sets forth PNMR's long-term contractual obligations as of December 31, 2017. See Note 7 for further details about the Company's significant leases.

	Payments Due				
Contractual Obligations	2018	2019-2020	2021-2022	2023 and Thereafter	Total
			(In thousands)		
Long-term debt [a]	$ 257,293	$ 510,866	$ 367,650	$ 1,295,698	$ 2,431,507
Interest on long-term debt [b]	110,771	159,647	132,460	708,144	1,111,022
Operating leases [c]	26,802	50,846	50,244	60,708	188,600
Transmission service arrangements	16,956	21,102	17,793	9,440	65,291
Coal contracts [d]	104,782	224,477	192,507	375,941	897,707
Coal mine decommissioning [e] [f]	10,689	22,469	24,498	157,772	215,428
Nuclear decommissioning funding requirements [f]	2,637	5,274	5,274	—	13,185
SJGS decommissioning funding requirements	—	—	16,920	—	16,920
Outsourcing	4,555	3,430	—	—	7,985
Pension and retiree medical [g]	1,936	3,778	9,092	—	14,806
Equity contributions to NMRD [h]	7,700	—	—	—	7,700
Construction expenditures [i]	500,205	1,027,235	1,184,627	—	2,712,067
Total [j]	$ 1,044,326	$ 2,029,124	$ 2,001,065	$ 2,607,703	$ 7,682,218

[a] Represents total long-term debt, excluding unamortized discounts, premiums, and issuance costs (Note 6)
[b] Represents interest payments during the period
[c] The operating lease amounts include payments under the PVNGS leases through the expiration of the leases; see Off-Balance Sheet Arrangements above, Note 7, and Note 9
[d] Represents only certain minimum payments that may be required under the coal contracts in effect on December 31, 2017 if no deliveries are taken
[e] Includes funding of trusts for post-term reclamation related to the mines serving SJGS and Four Corners (Note 16)
[f] These obligations represent funding based on the current rate of return on investments
[g] The Company only forecasts funding for its pension and retiree medical plans for the next five years
[h] Represents commitments to fund NMRD for its contractual construction obligations
[i] Represents forecasted construction expenditures, including nuclear fuel, under which substantial commitments have been made; the Company only forecasts capital expenditures for the next five years; see Capital Requirements above and Note 14
[j] PNMR is unable to reasonably estimate the timing of liability for uncertain income tax positions (Note 11) in individual years due to uncertainties in the timing of the effective settlement of tax positions and, therefore, PNMR's liability of $9.4 million is not reflected in this table; amounts PNM is obligated to pay Valencia are not included above since Valencia is consolidated by PNM in accordance with GAAP, as discussed in Note 9; no amounts are included above for the New Mexico Wind, Lightning Dock Geothermal, and Red Mesa Wind PPAs and Tri-State hazard sharing agreement since there are no minimum payments required under those agreements

Contingent Provisions of Certain Obligations

PNMR, PNM, and TNMP have a number of debt obligations and other contractual commitments that contain contingent provisions. Some of these, if triggered, could affect the liquidity of the Company. In the unlikely event that the contingent requirements were to be triggered, PNMR, PNM, or TNMP could be required to provide security, immediately pay outstanding obligations, or be prevented from drawing on unused capacity under certain credit agreements. The most significant consequences resulting from these contingent requirements are detailed in the discussion below.

The PNMR Revolving Credit Facility, PNM Revolving Credit Facility, PNM 2017 New Mexico Credit Facility, TNMP Revolving Credit Facility, and the PNMR 2015 Term Loan Agreement contain "ratings triggers," for pricing purposes only. If PNMR, PNM, or TNMP is downgraded or upgraded by the ratings agencies, the result would be an increase or decrease in interest cost. In addition, these facilities, as well as the Company's other term loans, each contain a covenant requiring the maintenance

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of debt-to-capital ratios of not more than 65%. If that ratio were to exceed 65%, the entity could be required to repay all borrowings under its facility, be prevented from borrowing on the unused capacity under the facility, and be required to provide collateral for all outstanding letters of credit issued under the facility.

If a contingent requirement were to be triggered under the PNM facilities resulting in an acceleration of the repayment of outstanding loans, a cross-default provision in the PVNGS leases could occur if the accelerated amount is not paid. If a cross-default provision is triggered, the PVNGS lessors have the ability to accelerate their rights under the leases, including acceleration of all future lease payments. The Company's revolving credit facilities and term loan agreements also include cross-default provisions.

PNM's standard purchase agreement for the procurement of natural gas for its fuel needs contains a contingent requirement that could require PNM to provide collateral for its gas purchase obligations if the seller were to reasonably believe that PNM was unable to fulfill its payment obligations under the agreement.

The master agreement for the sale of electricity in the WSPP contains a contingent requirement that could require PNM to provide collateral if the credit ratings on its debt falls below investment grade. The WSPP agreement also contains a contingent requirement, commonly called a material adverse change provision, which could require PNM to provide collateral if a material adverse change in its financial condition or operations were to occur. Additionally, PNM utilizes standard derivative contracts to financially hedge and trade energy. These agreements contain contingent requirements that require PNM to provide security if the credit rating on its debt falls below investment grade. The Company believes its financing arrangements are sufficient to meet the requirements of the contingent provisions.

No conditions have occurred that would result in any of the above contingent provisions being implemented.

Capital Structure

The capitalization tables below include the current maturities of long-term debt, but do not include short-term debt and do not include operating lease obligations as debt.

	December 31,	
PNMR	**2017**	**2016**
PNMR common equity	40.9%	41.1%
Preferred stock of subsidiary	0.3%	0.3%
Long-term debt	58.8%	58.6%
Total capitalization	100.0%	100.0%
PNM		
PNM common equity	46.0%	46.0%
Preferred stock	0.4%	0.4%
Long-term debt	53.6%	53.6%
Total capitalization	100.0%	100.0%
TNMP		
Common equity	56.9%	58.5%
Long-term debt	43.1%	41.5%
Total capitalization	100.0%	100.0%

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OTHER ISSUES FACING THE COMPANY

Climate Change Issues

Background

For the past several years, management has identified multiple risks and opportunities related to climate change, including potential environmental regulation, technological innovation, and availability of fuel and water for operations, as among the most significant risks facing the Company. Accordingly, these risks are overseen by the full Board in order to facilitate more integrated risk and strategy oversight and planning. Board oversight includes understanding the various challenges and opportunities presented by these risks, including the financial consequences that might result from potential federal and/or state regulation of GHG; plans to mitigate the risks; and the impacts these risks may have on the Company's strategy. In addition, the Board approves certain PNM investments in environmental equipment and grid modernization technologies.

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Management periodically updates the Board on implementation of the corporate environmental policy and the Company's environmental management systems, promotion of energy efficiency, and use of renewable resources. The Board is also advised of the Company's practices and procedures to assess the sustainability impacts of operations on the environment. Management has recently published, with Board oversight, a Climate Change Report available at http://www.pnmresources.com/about-us/sustainability-portal.aspx, that details PNM's efforts to transition to a coal-free generation portfolio. The Board considers issues associated with climate change, the Company's GHG exposures, and the financial consequences that might result from potential federal and/or state regulation of GHG.

Changes in the climate are generally not expected to have material consequences to the Company in the near-term. The Company cannot anticipate or predict the potential long-term effects of climate change or climate change related regulation on its assets and operations.

GHG Exposures

In 2017, GHG associated with PNM's interests in its fossil-fueled generating plants included approximately 6.9 million metric tons of CO_2, which comprises the vast majority of

PNM's GHG. By comparison, the total GHG in the United States in 2015, the latest year for which EPA has published final data, were approximately 6.6 billion metric tons (in CO_2 equivalents), of which approximately 5.4 billion metric tons were CO_2.

As of January 1, 2018, approximately 67.9% of PNM's generating capacity, including resources owned, leased, and under PPAs, all of which is located within the United States, consisted of coal or gas-fired generation that produces GHG. This reflects the retirement of SJGS Units 2 and 3 that occurred in December 2017 and the restructuring of ownership in SJGS Unit 4. These events reduced PNM's entitlement in SJGS from 783 MW to 562 MW and will cause the Company's output of GHG to decrease in 2018 compared to 2017. Many factors affect the amount of GHG emitted, including plant performance, economic dispatch, and the availability of renewable resources. For example, between 2007 and 2017, production from New Mexico Wind has varied from a high of 580 GWh in 2011 to a low of 405 GWh in 2014. Variations are primarily due to how much and how often the wind blows. In addition, if PVNGS experienced prolonged outages or if PNM's entitlement from PVNGS were reduced, PNM might be required to utilize other power supply resources such as gas-fired generation, which could increase GHG.

PNM has several programs underway to reduce or offset GHG from its resource portfolio, thereby reducing its exposure to climate change regulation. See Note 17. As described in Note 16, PNM received approval for the December 31, 2017 shutdown of SJGS Units 2 and 3 as part of its strategy to address the regional haze requirements of the CAA. The shutdown of SJGS Units 2 and 3 is expected to result in a reduction of GHG for the entire station of approximately 50%, including an overall reduction of approximately 40% of GHG from the Company's owned interests. In addition, as discussed in Note 17, PNM's 2017 IRP indicates exiting ownership in the remaining SJGS units in 2022 and Four Corners in 2031 would provide long-term cost savings to its customers and would further reduce PNM's GHG. PNM owns utility-scale solar generation with a total generation capacity of 107 MW. Since 2003, PNM has purchased the entire output of New Mexico Wind, which has an aggregate capacity of 204 MW, and, since January 2015, has purchased the full output of Red Mesa Wind, which has an aggregate capacity of 102 MW. PNM has a 20-year PPA for the output of Lightning Dock Geothermal, which began providing power to PNM in January 2014. The current capacity of the geothermal facility is 4 MW. On November 15, 2017 the NMPRC approved PNM's 2018 renewable energy procurement plan (Note 17). As a result, PNM will acquire an additional 80 GWh in 2019 and 105 GWh in 2020 from a re-powering of New Mexico Wind; an additional 55 GWh in 2019 and 77 GWh in 2020 from a re-powering of Lightning Dock Geothermal; and PNM will construct 50 MW of new solar facilities in 2018. Additionally, PNM has a customer distributed solar generation program that represented 81.6 MW at December 31, 2017. PNM's distributed solar programs will reduce PNM's annual production from fossil-fueled electricity generation by about 180 GWh. PNM has offered its customers a comprehensive portfolio of energy efficiency and load management programs since 2007, with a budget of $23.6 million for the 2018 program year. Cumulative annual savings from these programs were approximately 625 GWh of electricity through 2017. Over the next 20 years, PNM projects energy efficiency and load management programs will provide the equivalent of approximately 9,600 GWh of electricity, which will avoid at least 5.2 million metric tons of CO_2 based upon projected emissions from PNM's system-wide resources. These estimates are subject to change because of the uncertainty of many of the underlying variables, including changes in demand for electricity, and complex relationships between those variables.

Because of PNM's dependence on fossil-fueled generation, legislation or regulation that imposes a limit or cost on GHG could impact the cost at which electricity is produced. While PNM expects to recover any such costs through rates, the timing and outcome of proceedings for cost recovery are uncertain. In addition, to the extent that any additional costs are recovered through rates, customers may reduce their usage, relocate facilities to other areas with lower energy costs, or take other actions that ultimately will adversely impact PNM.

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Other Climate Change Risks

PNM's generating stations are located in the arid southwest. Access to water for cooling for some of these facilities is critical to continued operations. Forecasts for the impacts of climate change on water supply in the southwest range from reduced precipitation to changes in the timing of precipitation. In either case, PNM's generating facilities requiring water for cooling will need to mitigate the impacts of climate change through adaptive measures. Current measures employed by PNM generating stations such as air cooling, use of grey water, improved reservoir operations, and shortage sharing arrangements with other water users will continue to be important to sustain operations.

PNM's service areas occasionally experience periodic high winds, forest fires, and severe thunderstorms. TNMP has operations in the Gulf Coast area of Texas, which experiences periodic hurricanes and drought conditions. In addition to potentially causing physical damage to Company-owned facilities, which disrupts the ability to transmit and/or distribute energy, weather and other events of nature can temporarily reduce customers' usage and demand for energy. During the third quarter of 2017, Hurricane Harvey had significant impacts on the Gulf Coast region, including certain areas serviced by TNMP. While Hurricane Harvey did not have a significant impact on TNMP's facilities, the hurricane impacted customer usage and could impact future usage or create resource constraints that could delay or disrupt the supply of materials necessary to maintain historical levels of system reliability.

EPA Regulation

In April 2007, the US Supreme Court held that EPA has the authority to regulate GHG under the CAA. This decision heightened the importance of this issue for the energy industry. In December 2009, EPA released its endangerment finding for emissions from new motor vehicles, stating that the atmospheric concentrations of six key greenhouse gases (CO_2, methane, nitrous oxides, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride) endanger the public health and welfare of current and future generations. In May 2010, EPA released the final PSD and Title V Greenhouse Gas Tailoring Rule (the "Tailoring Rule") to address GHG from stationary sources under the CAA permitting programs. The purpose of the rule was to "tailor" the applicability of two programs, the PSD construction permit and Title V operating permit programs, to avoid impacting millions of small GHG emitters. On June 23, 2014, the US Supreme Court found EPA lacked authority to "tailor" the CAA's unambiguous numerical thresholds of 100 or 250 tons per year, and thus held EPA may not require a source to obtain a PSD permit solely on the basis of its potential GHG emissions. However, the court upheld EPA's authority to apply the PSD program for GHGs to "anyway" sources – those sources that have to comply with the PSD program for other non-GHG pollutants.

On June 25, 2013, then President Obama announced his Climate Action Plan, which outlined how his administration planned to cut GHG in the United States, prepare the country for the impacts of climate change, and lead international efforts to combat and prepare for global warming. The plan proposed actions that would lead to the reduction of GHG by 17% below 2005 levels by 2020.

On August 3, 2015, EPA responded to the Climate Action Plan by issuing three separate but related actions: (1) the final Carbon Pollution Standards for new, modified, and reconstructed power plants (under Section 111(b)); (2) the final Clean Power Plan for existing power plants (under Section 111(d)); and (3) a proposed federal plan associated with the final Clean Power Plan.

EPA's Carbon Pollution Standards for new sources (those constructed after January 8, 2014) established separate standards for gas- and coal-fired units. The standards reflect the degree of emission limitation achievable through the application of what EPA determined to be the best system of emission reduction ("BSER") demonstrated for each type of unit. For newly constructed and reconstructed base load natural gas-fired stationary combustion turbines, EPA finalized a standard based on efficient natural gas combined cycle technology. The final standards for coal-fired power plants vary depending on whether the unit is new, modified, or reconstructed.

The final Clean Power Plan established numeric "emission standards" for existing electric generating units – one for "fossil-steam" units (coal- and oil-fired units) and one for natural gas-fired units (combined cycle only). The emission standards are based on emission reduction opportunities that EPA deemed achievable using technical assumptions for three "building blocks": efficiency improvements at coal-fired EGUs, displacement of affected EGUs with renewable energy, and displacement of coal-fired generation with natural gas-fired generation.

Multiple states, utilities, and trade groups filed petitions for review in the DC Circuit to challenge both the Carbon Pollution Standards for new sources and the Clean Power Plan for existing sources. Numerous parties also simultaneously filed motions to stay the Clean Power Plan during the litigation. The DC Circuit first refused to stay the rule, but 29 states and state agencies successfully petitioned the US Supreme Court for a stay, which was granted on February 9, 2016. As a result, the Clean Power Plan is not in effect and neither states nor sources are obliged to comply with its requirements. With the US Supreme Court stay in place, the DC Circuit heard oral arguments on the merits of the Clean Power Plan on September 27, 2016 in front of a 10-judge

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en banc panel. However, before the DC Circuit could issue an opinion, President Trump took office and his administration asked the court to hold the case in abeyance while the rule is re-evaluated, which the court granted.

On March 28, 2017, President Trump issued an Executive Order titled “Promoting Energy Independence and Economic Growth.” Among its goals are to “promote clean and safe development of our Nation’s vast energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production, constrain economic growth, and prevent job creation.” The order rescinds several key pieces of the Obama Administration’s climate agenda, including the Climate Action Plan and the Final Guidance on Consideration of Climate Change in NEPA Reviews. It directs agencies to review and suspend, revise or rescind any regulations or agency actions that potentially burden the development or use of domestically produced energy resources.

Most notably, the order directs EPA to immediately review and, if appropriate and consistent with law, suspend, revise, or rescind (1) the Carbon Pollution Standards for new, reconstructed or modified electric utilities, (2) the Clean Power Plan, (3) the Proposed Clean Power Plan Model Trading Rules, and (4) the Legal Memorandum supporting the Clean Power Plan. In response, the EPA signed a NOPR to repeal the Clean Power Plan on October 10, 2017. The notice proposes a legal interpretation concluding that the Clean Power Plan exceeds EPA’s statutory authority. EPA recently announced that it will continue to accept comments on that proposed interpretation until April 26, 2018. Any final rule will likely be subject to judicial review. EPA indicated it has not determined whether it will promulgate a new rule under section 111(d) or what form a new rule would take, but it did seek comment on that question in a separate advanced notice of proposed rulemaking published December 28, 2017.

PNM is unable to predict the impact to the Company of this Executive Order or the potential repeal of the Clean Power Plan. It is uncertain the direction EPA will take, if any, to replace the existing rule. If a future regulation limiting GHG from fossil-fueled EGUs is adopted, such regulations could impact PNM’s existing and future fossil-fueled EGUs. The existing Carbon Pollution Standards covering new sources could also impact PNM’s generation fleet, although that rule remains under review by EPA and the DC Circuit.

Federal Legislation

Prospects for enactment in Congress of legislation imposing a new or enhanced regulatory program to address climate change are highly unlikely in 2018.

State and Regional Activity

Pursuant to New Mexico law, each utility must submit an IRP to the NMPRC every three years to evaluate renewable energy, energy efficiency, load management, distributed generation, and conventional supply-side resources on a consistent and comparable basis. The IRP is required to take into consideration risk and uncertainty of fuel supply, price volatility, and costs of anticipated environmental regulations when evaluating resource options to meet supply needs of the utility’s customers. The NMPRC requires that New Mexico utilities factor a standardized cost of carbon emissions into their IRPs using prices ranging between $8 and $40 per metric ton of CO_2 emitted and escalating these costs by 2.5% per year. Under the NMPRC order, each utility must analyze these standardized prices as projected operating costs. Reflecting the developing nature of this issue, the NMPRC order states that these prices may be changed in the future to account for additional information or changed circumstances. Although these prices may not reflect the costs that ultimately will be incurred, PNM is required to use these prices for purposes of its IRP. As discussed in Note 17, in its 2017 IRP, PNM analyzed resource portfolio plans for scenarios that assumed SJGS will operate beyond the end of the current coal supply agreement that runs through June 30, 2022 and for scenarios that assumed SJGS will cease operations by the end of 2022. The key findings of the 2017 IRP include that exiting SJGS in 2022 would provide long-term cost benefits to PNM’s customers and that PNM exiting its ownership interest in Four Corners in 2031 would also save customers money. The materials presented in the IRP process are available at www.pnm.com\irp.

On August 30, 2017, Western Resource Advocates provided the NMPRC with a presentation on a proposed rulemaking for the adoption of a clean energy standard in New Mexico and a suggestion that the NMPRC issue a NOPR. The NMAG’s office and Prosperity Works joined in the petition. The proposed clean energy standard, if adopted, would require utilities to reduce carbon emissions by four percent per year for the next 20 years. The NMPRC has convened a series of workshops to develop a clean energy standard rule that could be proposed for a future rulemaking proceeding. The major topic areas discussed at the workshops are: jurisdictional and other legal issues; selection of the timeframe for the emissions baseline year to be used, unspecified power, and electric vehicle credits; and cost responsibilities, benefits, reasonable cost threshold, impact on rates, compliance issues, reliability impacts and unintended consequences. Workshops are scheduled to continue in 2018.

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International Accords

The United Nations Framework Convention on Climate Change (“UNFCCC”) is an international environmental treaty that was negotiated at the 1992 United Nations Conference on Environment and Development (informally known as the Earth Summit) and entered into force in March 1994. The objective of the treaty is to “stabilize greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system.” Parties to the UNFCCC, including the United States, have been meeting annually in Conferences of the Parties (“COP”) to assess progress in meeting the objectives of the UNFCCC.

On December 12, 2015, the Paris Agreement was finalized during the 2015 COP. The agreement, which was agreed to by more than 190 nations, requires that countries submit Nationally Determined Contributions (“NDCs”). NDCs reflect national targets and actions that arise out of national policies and elements relating to oversight, guidance and coordination of actions to reduce emissions by all countries. In November 2014, then President Obama announced the United States’ commitment to reduce GHG, on an economy-wide basis, by 26%-28% from 2005 levels by the year 2025. The United States NDC is part of an overall effort by the former administration to have the United States achieve economy-wide reductions of around 80% by 2050. The former administration’s GHG reduction target for the electric utility industry is a key element of its NDC and is based on EPA’s final GHG regulations for new, existing, and modified and reconstructed sources. The United States was one of 189 nations that offered intended NDCs. Thresholds for the number of countries necessary to ratify or accede to the Paris Agreement and total global GHG percentage were achieved on October 5, 2016, and the Paris Agreement entered into force on November 4, 2016. To date, 174 countries have ratified the Paris Agreement. On June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement. In his public statement, he indicated that the United States would "begin negotiations to reenter either the Paris Accord or a .... new transaction on terms that are fair to the United States, its businesses, its workers, its people, its taxpayers." To date there have been no specific details as to how this will be accomplished.

PNM will continue to monitor the United States’ involvement in international accords, but the potential impact that such accords may have on the Company cannot be determined

at this time.

Assessment of Legislative/Regulatory Impacts

The Company has assessed, and continues to assess, the impacts of climate change legislation and regulation on its business. This assessment is ongoing and future changes arising out of the legislative or regulatory process could impact the assessment significantly. PNM's assessment includes assumptions regarding specific GHG limits; the timing of implementation of these limits; the possibility of a market-based trading program, including the associated costs and the availability of emission credits or allowances; the development of emission reduction and/or renewable energy technologies; and provisions for cost containment. Moreover, the assessment assumes various market reactions such as the price of coal and gas and regional plant economics. These assumptions are, at best, preliminary and speculative. However, based upon these assumptions, the enactment of climate change legislation or regulation could, among other things, result in significant compliance costs, including large capital expenditures by PNM, and could jeopardize the economic viability of certain generating facilities. See Note 16. In turn, these consequences could lead to increased costs to customers and affect results of operations, cash flows, and financial condition if the incurred costs are not fully recovered through regulated rates. Higher rates could also contribute to reduced usage of electricity. PNM's assessment process is too preliminary and speculative at this time for a meaningful prediction of financial impact.

Transmission Issues

At any given time, FERC has various notices of inquiry and rulemaking dockets related to transmission issues pending. Such actions may lead to changes in FERC administrative rules or ratemaking policy, but have no time frame in which action must be taken or a docket closed with no further action. Further, such notices and rulemaking dockets do not apply strictly to PNM, but will have industry-wide effects in that they will apply to all FERC-regulated entities. PNM monitors and often submits comments taking a position in such notices and rulemaking dockets or may join in larger group responses. PNM often cannot determine the full impact of a proposed rule and policy change until the final determination is made by FERC and PNM is unable to predict the outcome of these matters.

On November 24, 2009, FERC issued Order 729 approving two Modeling, Data, and Analysis Reliability Standards ("Reliability Standards") submitted by NERC – MOD-001-1 (Available Transmission System Capability) and MOD-029-1 (Rated System Path Methodology). Both MOD-001-1 and MOD-029-1 require a consistent approach, provided for in the Reliability Standards, to measuring the total transmission capability ("TTC") of a transmission path. The TTC level established using the two Reliability Standards could result in a reduction in the available transmission capacity currently used by PNM to deliver generation resources necessary for its jurisdictional load and for fulfilling its obligations to third-party users of the PNM transmission system.

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During the first quarter of 2011, at the request of PNM and other southwestern utilities, NERC advised all transmission owners and transmission service providers that the implementation of portions of the MOD-029 methodology for "Flow Limited" paths has been delayed until such time as a modification to the standard can be developed that will mitigate the technical concerns identified by the transmission owners and transmission service providers. PNM and other western utilities filed a Standards Action Request with NERC in the second quarter of 2012.

NERC initiated an informal development process to address directives in Order 729 to modify certain aspects of the MOD standards, including MOD-001 and MOD-029. The modifications to this standard would retire MOD-029 and require each transmission operator to determine and develop methodology for TTC values for MOD-001.

A final ballot for MOD-001-2 concluded on December 20, 2013 and received sufficient affirmative votes for approval. On February 10, 2014, NERC filed with FERC a petition for approval of MOD-001-2 and retirement of reliability standards MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a, and MOD-030-2. On June 19, 2014, FERC issued a NOPR to approve a new reliability standard. The MOD-001-2 standard will become effective on the first day of the calendar quarter that is 18 months after the date the standard is approved by FERC. MOD-001-2 will replace multiple existing reliability standards and will remove the risk of reduced TTC for PNM and other western utilities.

Financial Reform Legislation

The Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Reform Act"), enacted in July 2010, includes provisions that will require certain over-the-counter derivatives, or swaps, to be centrally cleared and executed through an exchange or other approved trading facility. It also includes provisions related to swap transaction reporting and record keeping and may impose margin requirements on swaps that are not centrally cleared. The United States Commodity Futures Trading Commission ("CFTC") has published final rules defining several key terms related to the act and has set compliance dates for various types of market participants. The Dodd-Frank Reform Act provides exemptions from certain requirements, including an exception to the mandatory clearing and swap facility execution requirements for commercial end-users that use swaps to hedge or mitigate commercial risk. PNM has elected the end-user exception to the mandatory clearing requirement. PNM expects to be in compliance with the Dodd-Frank Reform Act and related rules within the time frames required by the CFTC. However, as a result of implementing and complying with the Dodd-Frank Reform Act and related rules, PNM's swap activities could be subject to increased costs, including from higher margin requirements. The Trump Administration has indicated that the provisions of the Dodd-Frank Reform Act will be reviewed and certain regulations may be rolled back, but no formal action has been taken yet. At this time, PNM cannot predict the ultimate impact the Dodd-Frank Reform Act may have on PNM's financial condition, results of operations, cash flows, or liquidity.

Other Matters

See Notes 16 and 17 for a discussion of commitments and contingencies and rate and regulatory matters. See Note 1 for a discussion of accounting pronouncements that have been issued, but are not yet effective and have not been adopted by the Company.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to apply accounting policies and to make estimates and judgments that best provide the framework to report the results of operations and financial position for PNMR, PNM, and TNMP. As a result, there exists the likelihood that materially different amounts would be reported under different conditions or using different assumptions. Management has identified the following accounting policies that it deems critical to the portrayal of the financial condition and results of operations and that involve significant subjectivity. The following discussion provides information on the processes utilized by management in making judgments and assumptions as they apply to its critical accounting policies.

Unbilled Revenues

The Company records unbilled revenues representing management's assessment of the estimated amount of revenue earned from customers for services rendered between the meter-reading dates in a particular month and the end of that month. Unbilled revenues are estimated based on daily generation volumes, estimated customer usage by class, line losses, and applicable customer rates reflecting historical trends and experience. The estimate requires the use of various judgments and assumptions; significant changes to these judgments and assumptions could have a material impact to the Company's results of operations.

Regulatory Accounting

The Company is subject to the provisions of GAAP for rate-regulated enterprises and records assets and liabilities resulting from the effects of the ratemaking process, which would not be recorded under GAAP for non-regulated entities. Additional information concerning regulatory assets and liabilities is contained in Note 4.

The Company continually evaluates the probability that regulatory assets and liabilities will impact future rates and makes various assumptions in those analyses. The expectations of future rate impacts are generally based on orders issued by regulatory commissions or historical experience, as well as discussions with applicable regulatory authorities. If future recovery or refund ceases to be probable, the Company would be required to write-off the portion that is not recoverable or refundable in current period earnings.

The Company has made adjustments to regulatory assets and liabilities that affected its results of operations in the past due to changes in various factors and conditions impacting future cost recovery. Based on its current evaluation, the Company believes that future recovery of its regulatory assets is probable.

Impairments

Tangible long-lived assets are evaluated for impairment when events and circumstances indicate that the assets might be impaired in accordance with GAAP. These potential impairment indicators include management's assessment of fluctuating market conditions as a result of planned and scheduled customer purchase commitments; future market penetration; changing environmental requirements; fluctuating market prices resulting from factors including changing fuel costs and other economic conditions; long-term weather patterns; and other market trends. The amount of impairment recognized, if any, is the difference between the fair value of the asset and the carrying value of the asset and would reduce both the asset and current period earnings. Variations in the assessment of potential impairment or in the assumptions used to calculate an impairment could result in different outcomes, which could lead to significant effects on the Consolidated Financial Statements.

Goodwill is evaluated for impairment at least annually, or more frequently if events and circumstances indicate that the goodwill might be impaired. GAAP allows impairment testing to be performed based on either a qualitative analysis or quantitative analysis. Note 18 contains information on the impairment testing performed by the Company on goodwill. For 2017, the Company utilized a qualitative analysis for both the PNM and TNMP reporting units. No impairments were indicated in the Company's annual goodwill testing, which was performed as of April 1, 2017. Since the annual evaluation, there have been no indications that the fair values of the reporting units with recorded goodwill have decreased below the carrying values. The annual testing was based on certain critical estimates and assumptions. Changes in the estimates or the use of different assumptions could affect the determination of fair value and the conclusion of impairment for each reporting unit.

Application of the qualitative goodwill impairment test requires evaluating various events and circumstances to determine whether it is not more likely than not that the fair value of a reporting unit is less than its carrying amount. As a part of the Company's goodwill qualitative testing process for a reporting unit, various factors that are specific to the reporting unit as well as industry and macroeconomic factors are evaluated in order to determine whether these factors are reasonably likely to have a material impact on the fair value of the reporting unit. Examples of the factors that were considered in the qualitative testing of the goodwill include the results of the most recent quantitative impairment test, current and long-term forecasted financial results, regulatory environment, credit rating, changes in the interest rate environment, and operating strategy for the reporting unit. Based on the qualitative analysis performed in 2017 for both the PNM and TNMP reporting units, the Company concluded that there were no changes that were reasonably likely to cause the fair value of the reporting units to be less than their carrying value and determined that there was no impairment of goodwill. Although the Company believes all relevant factors were considered in the qualitative impairment analysis to reach the conclusion that goodwill is not impaired, significant changes in any one of the assumptions could produce a significantly different result potentially leading to the recording of an impairment that could have significant impacts on the results of operations and financial position of the Company.

Decommissioning and Reclamation Costs

PNM owns and leases nuclear and fossil-fuel generation facilities. In accordance with GAAP, PNM is only required to recognize and measure decommissioning liabilities for tangible long-lived assets for which a legal obligation exists. Accounting for decommissioning costs for nuclear and fossil-fuel generation involves significant estimates related to costs to be incurred many years in the future after plant closure. Decommissioning costs are based on site-specific estimates, which are updated periodically and involve numerous judgments and assumptions, including estimates of future decommissioning costs at current price levels, inflation rates, and discount rates. Changes in these estimates could significantly impact PNMR's and PNM's financial position, results of operations, and cash flows. Nuclear decommissioning costs are based on estimates of the costs for removing all radioactive and other structures at PVNGS. AROs, including nuclear decommissioning costs, are discussed in Note 15. Nuclear decommissioning costs represent approximately 80% of PNM's ARO liability. A 10% increase in the estimates of future de

commissioning costs at current price levels would have increased the ARO liability by $10.7 million at December 31, 2017. PVNGS Units 1 and 2 are included in PNM's retail rates while PVNGS Unit 3 was excluded through 2017, but is included beginning in 2018. PNM recognizes an expense and a corresponding liability for ultimate decommissioning of PVNGS. See Note 17 for information concerning the treatment of nuclear decommissioning in the NMPRC's order in PNM's NM 2015 Rate Case and PNM's appeal of that order.

In connection with both the SJGS coal agreement and the Four Corners fuel agreement, the owners are required to reimburse the mining companies for the cost of contemporaneous reclamation, as well as the costs for final reclamation of the coal mines. The reclamation costs are based on periodic site-specific studies that estimate the costs to be incurred in the future and are dependent upon numerous assumptions, including estimates of future reclamation costs at current price levels, inflation rates, and discount rates. A 10% increase in the estimates of future reclamation costs at current price levels would have increased the mine reclamation liability by $5.3 million at December 31, 2017. PNM considers the contemporaneous reclamation costs part of the cost of its delivered coal costs. The NMPRC has capped the amount that can be collected from ratepayers for final reclamation of the surface mines. If future estimates increase the liability for surface mine reclamation, the excess would be expensed at that time. See Note 16 for discussion of reclamation costs.

Pension and Other Postretirement Benefits

The Company maintains qualified defined benefit pension plans, postretirement benefit plans providing medical and dental benefits, and executive retirement programs. The net periodic benefit cost or income and the calculation of the projected benefit obligations are recognized in the Company's financial statements and depend on expected investment performance, the level of contributions made to the plans, and employee demographics. These calculations require the use of a number of actuarial assumptions and estimates. The most critical of the actuarial assumptions are the expected long-term rate of return, the discount rate, and projected health care cost trend rates. The Company reviews and evaluates its actuarial assumptions annually and adjusts them as necessary. Changes in the pension and OPEB assets and liabilities associated with these factors are not immediately recognized as net periodic benefit cost or income in results of operations, but are recognized in future years, generally, over the remaining life of the plan. However, these factors could have a significant impact on the financial position of the Company. Note 12 contains additional information about pension and OPEB obligations, including assumptions utilized in the calculations and impacts of changes in certain of those assumptions.

Accounting for Contingencies

The financial results of the Company may be affected by judgments and estimates related to loss contingencies. Contingencies related to litigation and claims, as well as

environmental and regulatory matters, also require the use of significant judgment and estimation. The Company attempts to take into account all known factors regarding the future outcome of contingent events and records an accrual for any contingent loss events that are both probable of occurring and can be reasonably estimated based upon current available information. However the actual outcomes can vary from any amounts accrued which could have a material effect on the results of operations and financial position of the Company. See Note 16 and Note 17.

Income Taxes

The Company's income tax expense and related balance sheet amounts involve significant judgment and use of estimates. Amounts of deferred income tax assets and liabilities, current and noncurrent accruals, and determination of uncertain tax positions involve judgment and estimates related to timing and probability of the recognition of income and deductions by taxing authorities. In addition, some temporary differences are accorded flow-through treatment by the Company's regulators and impact the Company's effective tax rate. In assessing the likelihood of the realization of deferred tax assets, management considers the estimated amount and character of future taxable income. Significant changes in these judgments and estimates could have a material impact on the results of operations and financial position of the Company. Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, the Company's forecasted financial condition and results of operations in future periods, and the final review from taxing authorities. See Note 11 for additional information, including a discussion of the impacts of tax reform under the Tax Cuts and Jobs Act enacted on December 22, 2017.

MD&A FOR PNM

RESULTS OF OPERATIONS

PNM operates in only one reportable segment, as presented above in Results of Operations for PNMR.

MD&A FOR TNMP

RESULTS OF OPERATIONS

TNMP operates in only one reportable segment, as presented above in Results of Operations for PNMR.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company manages the scope of its various forms of market risk through a comprehensive set of policies and procedures with oversight by senior level management through the RMC. The Board's Finance Committee sets the risk limit parameters. The RMC has oversight over the risk control organization. The RMC is assigned responsibility for establishing and enforcing the policies, procedures, and limits and evaluating the risks inherent in proposed transactions on an enterprise-wide basis. The RMC's responsibilities include:

- Establishing policies regarding risk exposure levels and activities in each of the business segments
- Approving the types of derivatives entered into for hedging
- Reviewing and approving hedging risk activities
- Establishing policies regarding counterparty exposure and limits
- Authorizing and delegating transaction limits
- Reviewing and approving controls and procedures for derivative activities
- Reviewing and approving models and assumptions used to calculate mark-to-market and market risk exposure
- Proposing risk limits to the Board's Finance Committee for its approval
- Reporting to the Board's Audit and Finance Committees on these activities

To the extent an open position exists, fluctuating commodity prices, interest rates, equity prices, and economic conditions can impact financial results and financial position, either favorably or unfavorably. As a result, the Company cannot predict with certainty the impact that its risk management decisions may have on its businesses, operating results, or financial position.

Commodity Risk

Information concerning accounting for derivatives and the risks associated with commodity contracts is set forth in Note 8, including a summary of the fair values of mark-to-market energy related derivative contracts included in the Consolidated Balance Sheets. During the years ended December 31, 2017 and 2016, the Company had no commodity derivative instruments designated as cash flow hedging instruments.

Commodity contracts, other than those that do not meet the definition of a derivative under GAAP, are recorded at fair value on the Consolidated Balance Sheets. The following table details the changes in the net asset or liability balance sheet position for mark-to-market energy transactions.

	Year Ended December 31,	
	2017	2016
Economic Hedges	(In thousands)	
Sources of fair value gain (loss):		
Net fair value at beginning of period	$ 2,885	$ 4,576
Amount realized on contracts delivered during period	(2,640)	(316)
Changes in fair value	(235)	(1,261)
Net mark-to-market change recorded in earnings	(2,875)	(1,577)
Net change recorded as regulatory liability	(104)	(114)
Net fair value at end of period	$ (94)	$ 2,885

All of the fair values as of December 31, 2017 were determined based on prices provided by external sources other than actively quoted market prices. All of the mark-to-market amounts will settle in 2018.

PNM is exposed to changes in the market prices of electricity and natural gas for the positions in its wholesale portfolio not covered by the FPPAC. The Company manages risks associated with these market fluctuations by utilizing various commodity instruments that may qualify as derivatives, including futures, forwards, options, and swaps. PNM uses such instruments to hedge its exposure to changes in the market prices of electricity and natural gas. PNM also uses such instruments under an NMPRC approved hedging plan to manage fuel and purchased power costs related to customers covered by its FPPAC.

PNM measures the market risk of its wholesale activities not covered by the FPPAC using a Monte Carlo VaR simulation model to report the possible loss in value from price

movements. VaR is not a measure of the potential accounting mark-to-market loss. The quantitative risk information is limited by the parameters established in creating the model. The Monte Carlo VaR methodology employs the following critical parameters: historical volatility estimates, market values of all contractual commitments, a three-day holding period, seasonally adjusted and cross-commodity correlation estimates, and a 95% confidence

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level. The instruments being evaluated may trigger a potential loss in excess of calculated amounts if changes in commodity prices exceed the confidence level of the model used.

PNM measures VaR for the positions in its wholesale portfolio (not covered by the FPPAC). For the year ended December 31, 2017, the high, low, and average VaR amounts were $0.7 million, $0.1 million, and $0.3 million. For the year ended December 31, 2016, the high, low and average VaR amounts were $1.3 million, $0.3 million, and $0.6 million. At December 31, 2017 and December 31, 2016, the VaR amounts for the PNM wholesale portfolio were $0.3 million and $0.6 million.

The VaR represents an estimate of the potential gains or losses that could be recognized on the Company's portfolios, subject to market risk, given volatility in the market, and is not necessarily indicative of actual results that may occur, since actual future gains and losses will differ from those estimated. Actual gains and losses may differ due to fluctuations in market prices, operating exposures, and the timing thereof, as well as changes to the underlying portfolios during the year. VaR limits were not exceeded during 2017 or 2016.

PNM has significantly reduced its market risk exposure through the inclusion of PVNGS Unit 3 in New Mexico retail rates and the hedging, through June 2022, of 36 MW of the 65 MW of SJGS Unit 4, which is treated as merchant plant. As a result, PNM is reviewing its risk level and associated processes, including the use of VaR as a risk metric.

Credit Risk

The Company is exposed to credit risk from its retail and wholesale customers, as well as the counterparties to derivative instruments. The Company conducts counterparty risk analysis across business segments and uses a credit management process to assess the financial conditions of counterparties. The following table provides information related to credit exposure by the credit worthiness (credit rating) and concentration of credit risk for wholesale counterparties, all of which will mature in less than two years.

Schedule of Credit Risk Exposure
December 31, 2017

Rating [1]	Credit Risk Exposure[2]	Number of Counter-parties >10%	Net Exposure of Counter-parties >10%
		(Dollars in thousands)	
External ratings:			
Investment grade	$ 2,534	1	$ 650
Non-investment grade	1	—	—
Split ratings	210	—	—
Internal ratings:			
Investment grade	84	—	—
Non-investment grade	3,027	1	2,957
Total	$ 5,856		$ 3,607

(1) The rating "Investment Grade" is for counterparties, or a guarantor, with a minimum S&P rating of BBB- or Moody's rating of Baa3. The category "Internal Ratings – Investment Grade" includes those counterparties that are internally rated as investment grade in accordance with the guidelines established in the Company's credit policy.

(2) The Credit Risk Exposure is the gross credit exposure, including long-term contracts (other than firm-requirements wholesale customers and the Tri-State hazard sharing agreement), forward sales, and short-term sales. The gross exposure captures the amounts from receivables/payables for realized transactions, delivered and unbilled revenues, and mark-to-market gains/losses. Gross exposures can be offset according to legally enforceable netting arrangements, but are not reduced by posted credit collateral. At December 31, 2017, PNMR held $0.9 million of cash collateral to offset its credit exposure.

Net credit risk for the Company's largest counterparty as of December 31, 2017 was $3.0 million.

As discussed in Note 16, PNMR's subsidiary, NM Capital, entered into the Westmoreland Loan to facilitate the acquisition of SJCC by WSJ, a subsidiary of Westmoreland, and PNMR has arranged for letters of credit to be issued to support the coal

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mining operations of SJCC. PNMR is exposed to credit risk under these arrangements in the event of default by WSJ. As of February 20, 2018, remaining required principal payments under the Westmoreland Loan are $2.7 million in 2018 (after reflecting the $5.6 million paid on February 1, 2018), $8.6 million in 2019, $23.3 million in 2020, and $16.4 million in 2021. In addition, the Westmoreland Loan requires that all cash flows of WSJ, in excess of normal operating expenses, capital additions, and operating reserves, be utilized for principal and interest payments under the loan until it is fully repaid. The Westmoreland Loan is secured by the assets of and the equity interests in SJCC. In the event of a default by WSJ, NM Capital would have the ability to take over the mining operations, the value of which PNMR believes approximates the amount outstanding under the Westmoreland Loan. Furthermore, PNMR considers the possibility of loss under the letters of credit to be remote as discussed in Note 9. Accordingly, PNMR does not consider its credit risk under these arrangements to be material.

Other investments have no significant counterparty credit risk.

Interest Rate Risk

The majority of the Company's long-term debt is fixed-rate debt and does not expose earnings to a major risk of loss due to adverse changes in market interest rates. However, the fair value of long-term debt instruments for PNMR, PNM, and TNMP would increase by 1.6%, 1.3%, and 3.5%, if interest rates were to decline by 50 basis points from their levels at December 31, 2017. In general, an increase in fair value would impact earnings and cash flows to the extent not recoverable in rates if all or a portion of debt instruments were acquired in the open market prior to their maturity. At February 20, 2018, PNMR, PNM, and TNMP had $182.4 million, $57.4 million, and $23.9 million of short-term debt outstanding under their

revolving credit facilities, which allow for a maximum aggregate borrowing capacity of $300.0 million for PNMR, $400.0 million for PNM, and $75.0 million for TNMP. PNM also had borrowings of $20.0 million under the $40.0 million PNM 2017 New Mexico Credit Facility at February 20, 2018. The revolving credit facilities, the PNM 2017 New Mexico Credit Facility, the $150.0 million PNMR 2015 Term Loan Agreement, the $100.0 million PNMR 2016 One-Year Term Loan Agreement (as extended), the $100.0 million PNMR 2016 Two-Year Term Loan Agreement, the $200.0 million PNM 2017 Term Loan Agreement, and the $125.0 million BTMU Term Loan Agreement bear interest at variable rates. On February 20, 2018, interest rates on borrowings averaged 2.83% for the PNMR Revolving Credit Facility, 2.48% for the PNMR 2015 Term Loan Agreement, 4.32% for the BTMU Term Loan Agreement, 2.39% for the PNMR 2016 One-Year Term Loan Agreement (as extended), 2.35% for the PNMR 2016 Two-Year Term Loan Agreement, 2.71% for the PNM Revolving Credit Facility, 2.70% for the PNM 2017 New Mexico Credit Facility, 2.30% for the PNM 2017 Term Loan Agreement, and 2.33% for the TNMP Revolving Credit Facility. The Company is exposed to interest rate risk to the extent of future increases in variable interest rates. However, as discussed in Note 6, PNMR has entered into hedging arrangements to effectively establish fixed interest rates on the PNMR 2015 Term Loan Agreement and $150.0 million of variable rate debt.

The investments held by PNM in trusts for decommissioning, reclamation, pension benefits, and other post-employment benefits had an estimated fair value of $967.0 million at December 31, 2017, of which 55.8% were fixed-rate debt securities that subject PNM to risk of loss of fair value with increases in market interest rates. If interest rates were to increase by 50 basis points from their levels at December 31, 2017, the decrease in the fair value of the fixed-rate securities would be 6.8%, or $36.7 million. Due to the funded status of the nuclear decommissioning trust and overall market performance, PNM began to re-balance the decommissioning investment portfolio in late 2017 to increase the percentage of the investments in fixed income (debt) securities to approximately 85%. The portfolio re-balancing was completed in early 2018 and is expected to increase the exposure related to interest rate risk and reduce the equity market risk referenced below. The securities held by TNMP in trusts for pension and other post-employment benefits had an estimated fair value of $73.7 million at December 31, 2017, of which 59.2% were fixed-rate debt securities that subject TNMP to risk of loss of fair value with movements in market interest rates. If interest rates were to increase by 50 basis points from their levels at December 31, 2017, the decrease in the fair value of the fixed-rate securities would be 8.2%, or $3.6 million.

PNM and TNMP do not directly recover or return through rates any losses or gains on the securities, including equity and alternative investments discussed below, in the trusts for decommissioning, reclamation, pension benefits, and other post-employment benefits. However, the overall performance of these trusts does enter into the periodic determinations of expense and funding levels, which are factored into the rate making process to the extent applicable to regulated operations. However, as described in Note 17, the NMPRC has ruled that PNM would not be able to include future contributions made by PNM for decommissioning of PVNGS, to the extent applicable to certain capacity previously leased by PNM, in rates charged to retail customers. PNM has appealed the NMPRC's ruling to the NM Supreme Court. PNM and TNMP are at risk for shortfalls in funding of obligations due to investment losses, including those from the equity market and alternatives investment risks discussed below to the extent not ultimately recovered through rates charged to customers.

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Equity Market Risk

The investments held by PNM in trusts for decommissioning and reclamation and trusts established for PNM's and TNMP's pension and post-employment benefits plans include certain equity securities at December 31, 2017. These equity securities expose PNM and TNMP to losses in fair value should the market values of the underlying securities decline. Equity securities comprised 30.3% and 25.5% of the securities held by the various PNM and TNMP trusts as of December 31, 2017. A hypothetical 10% decrease in equity prices would reduce the fair values of these funds by $29.3 million for PNM and $1.9 million for TNMP.

Alternatives Investment Risk

The Company had 13.6% of its pension assets invested in the alternatives asset class as of December 31, 2017. The Company's target for this class is 14%. This includes real estate, private equity, and hedge funds. These investments are limited partner structures that are multi-manager multi-strategy funds. This investment approach gives broad diversification and minimizes risk compared to a direct investment in any one component of the funds. The general partner oversees the selection and monitoring of the underlying managers. The Company's Corporate Investment Committee, assisted by its investment consultant, monitors the performance of the funds and general partner's investment process. There is risk associated with these funds due to the nature of the strategies and techniques and the use of investments that do not have readily determinable fair value. A hypothetical 10% decrease in equity prices would reduce the fair values of these funds by $8.5 million.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

PNM RESOURCES, INC. AND SUBSIDIARIES
PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES
TEXAS-NEW MEXICO POWER COMPANY AND SUBSIDIARIES

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MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of PNM Resources, Inc. and subsidiaries ("PNMR") is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended.

Management assessed the effectiveness of PNMR's internal control over financial reporting based on the *Internal Control – Integrated Framework (2013)* set forth by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment performed, management concludes that PNMR's internal control over financial reporting was effective as of December 31, 2017.

The effectiveness of our internal control over financial reporting as of and for the year ended December 31, 2017 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their audit report which is included herein.

/s/ Patricia K. Collawn
Patricia K. Collawn,
Chairman, President, and Chief Executive Officer

/s/ Charles N. Eldred
Charles N. Eldred
Executive Vice President and
Chief Financial Officer

S&P Global Market Intelligence

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MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Public Service Company of New Mexico and subsidiaries ("PNM") is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended.

Management assessed the effectiveness of PNM's internal control over financial reporting based on the *Internal Control – Integrated Framework (2013)* set forth by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment performed, management concludes that PNM's internal control over financial reporting was effective as of December 31, 2017.

/s/ Patricia K. Collawn
Patricia K. Collawn,
President and Chief Executive Officer

/s/ Charles N. Eldred
Charles N. Eldred
Executive Vice President and
Chief Financial Officer

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MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Texas-New Mexico Power Company and subsidiaries ("TNMP") is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended.

Management assessed the effectiveness of TNMP's internal control over financial reporting based on the *Internal Control – Integrated Framework (2013)* set forth by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment performed, management concludes that TNMP's internal control over financial reporting was effective as of December 31, 2017.

/s/ Patricia K. Collawn
Patricia K. Collawn,
Chief Executive Officer

/s/ Charles N. Eldred
Charles N. Eldred
Executive Vice President and
Chief Financial Officer

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Report of Independent Registered Public Accounting Firm

The Stockholders and Board of Directors
PNM Resources, Inc.:

Opinions on the Consolidated Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of PNM Resources, Inc. and subsidiaries (the Company) as of December 31, 2017 and 2016, the related consolidated statements of earnings, consolidated statements of comprehensive income, consolidated statements of changes in equity, and consolidated statements of cash flows for each of the years in the three-year period ended December 31, 2017, the related notes and financial statement Schedule I – Condensed Financial Information of Parent Company and Schedule II – Valuation and Qualifying Accounts (collectively, the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Basis for Opinion

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable

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assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

We have served as the Company's auditor since 2013.

Albuquerque, New Mexico
March 1, 2018

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Report of Independent Registered Public Accounting Firm

The Stockholders and Board of Directors
Public Service Company of New Mexico:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Public Service Company of New Mexico and subsidiaries (the Company) as of December 31, 2017 and 2016, the related consolidated statements of earnings (loss), consolidated statements of comprehensive income (loss), consolidated statements of changes in equity, and consolidated statements of cash flows for each of the years in the three-year period ended December 31, 2017, the related notes and Schedule II – Valuation and Qualifying Accounts (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 2013.

Albuquerque, New Mexico
March 1, 2018

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Report of Independent Registered Public Accounting Firm

The Stockholder and Board of Directors
Texas-New Mexico Power Company:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Texas-New Mexico Power Company and subsidiaries (the Company) as of December 31, 2017 and 2016, the related consolidated statements of earnings, consolidated statements of changes in common stockholder's equity, and consolidated statements of cash flows for each of the years in the three-year period ended December 31, 2017, the related notes and Schedule II – Valuation and Qualifying Accounts (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement

of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 2013.

Albuquerque, New Mexico
March 1, 2018

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PNM RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EARNINGS

	Year Ended December 31,		
	2017	**2016**	**2015**
	(In thousands, except per share amounts)		
Electric Operating Revenues	$ 1,445,003	$ 1,362,951	$ 1,439,082
Operating Expenses:			
Cost of energy	407,479	380,596	464,649
Administrative and general	186,345	191,514	179,100
Energy production costs	137,450	146,187	176,752
Regulatory disallowances and restructuring costs	27,036	15,011	167,471
Depreciation and amortization	231,942	209,110	185,919
Transmission and distribution costs	71,576	66,227	69,157
Taxes other than income taxes	76,690	76,321	71,684
Total operating expenses	1,138,518	1,084,966	1,314,732
Operating income	306,485	277,985	124,350
Other Income and Deductions:			
Interest income	15,916	22,293	6,498
Gains on available-for-sale securities	27,161	19,517	16,060
Other income	19,515	17,796	26,833
Other (deductions)	(15,693)	(13,784)	(12,728)
Net other income and deductions	46,899	45,822	36,663
Interest Charges	127,625	128,633	114,860
Earnings before Income Taxes	225,759	195,174	46,153
Income Taxes	130,340	63,278	15,075
Net Earnings	95,419	131,896	31,078
(Earnings) Attributable to Valencia Non-controlling Interest	(15,017)	(14,519)	(14,910)
Preferred Stock Dividend Requirements of Subsidiary	(528)	(528)	(528)
Net Earnings Attributable to PNMR	$ 79,874	$ 116,849	$ 15,640
Net Earnings Attributable to PNMR per Common Share:			
Basic	$ 1.00	$ 1.47	$ 0.20
Diluted	$ 1.00	$ 1.46	$ 0.20

The accompanying notes, as they relate to PNMR, are an integral part of these consolidated financial statements.

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PNM RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2017	**2016**	**2015**
		(In thousands)	
Net Earnings	$ 95,419	$ 131,896	$ 31,078
Other Comprehensive Income (Loss):			
Unrealized Gains on Available-for-Sale Securities:			

Unrealized holding gains arising during the period, net of income tax (expense) of $(10,927), $(304), and $(4,310)	17,233	474	6,688
Reclassification adjustment for (gains) included in net earnings, net of income tax expense of $6,816, $8,639, and $11,181	(10,751)	(13,500)	(17,350)
Pension Liability Adjustment:			
Experience gains (losses), net of income tax (expense) benefit of $(919), $7,219, and $1,726	2,699	(11,282)	(2,679)
Reclassification adjustment for amortization of experience (gains) losses recognized as net periodic benefit cost, net of income tax expense (benefit) of $(2,504), $(2,148), and $(2,332)	3,948	3,356	3,620
Fair Value Adjustment for Cash Flow Hedges:			
Change in fair market value, net of income tax (expense) benefit of $(388), $341, and $(28)	612	(533)	44
Reclassification adjustment for (gains) losses included in net earnings, net of income tax expense (benefit) of $(225), $(298), and $0	356	466	—
Total Other Comprehensive Income (Loss)	14,097	(21,019)	(9,677)
Comprehensive Income	109,516	110,877	21,401
Comprehensive (Income) Attributable to Valencia Non-controlling Interest	(15,017)	(14,519)	(14,910)
Preferred Stock Dividend Requirements of Subsidiary	(528)	(528)	(528)
Comprehensive Income Attributable to PNMR	$ 93,971	$ 95,830	$ 5,963

The accompanying notes, as they relate to PNMR, are an integral part of these consolidated financial statements.

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PNM RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017	**2016**	**2015**
		(In thousands)	
Cash Flows From Operating Activities:			
Net earnings	$ 95,419	$ 131,896	$ 31,078
Adjustments to reconcile net earnings to net cash flows from operating activities:			
Depreciation and amortization	268,194	242,033	222,861
Deferred income tax expense	130,528	63,805	16,451
Net unrealized (gains) losses on commodity derivatives	2,875	1,577	5,188
Realized (gains) on available-for-sale securities	(27,161)	(19,517)	(16,060)
Stock based compensation expense	6,194	5,634	4,863
Regulatory disallowances and restructuring costs	27,036	15,011	167,471
Allowance for equity funds used during construction	(9,516)	(4,949)	(10,430)
Other, net	2,329	3,060	3,934
Changes in certain assets and liabilities:			
Accounts receivable and unbilled revenues	(1,846)	2,543	(3,298)
Materials, supplies, and fuel stock	1,473	(4,169)	(180)
Other current assets	32,298	(2,469)	29,370
Other assets	(5,486)	(42,864)	2,369
Accounts payable	14,468	3,159	(32,269)
Accrued interest and taxes	(327)	3,345	4,957
Other current liabilities	(6,513)	(12,509)	2,633
Other liabilities	(5,503)	29,868	(42,064)
Net cash flows from operating activities	524,462	415,454	386,874
Cash Flows From Investing Activities:			
Additions to utility and non-utility plant	(500,461)	(600,076)	(558,589)
Proceeds from sales of available-for-sale securities	637,492	522,601	252,174
Purchases of available-for-sale securities	(650,284)	(538,383)	(262,548)
Return of principal on PVNGS lessor notes	—	8,547	21,694
Investments in NMRD	(4,077)	—	—
Disbursements from NMRD	12,415	—	—
Investment in Westmoreland Loan	—	(122,250)	—
Principal repayments on Westmoreland Loan	38,360	30,000	—
Other, net	392	186	2,741
Net cash flows from investing activities	(466,163)	(699,375)	(544,528)

The accompanying notes, as they relate to PNMR, are an integral part of these consolidated financial statements.

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PNM RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017	**2016**	**2015**
		(In thousands)	
Cash Flows From Financing Activities:			
Short-term loan	—	100,000	50,000
Repayment of short-term loan	—	(150,000)	—
Revolving credit facilities borrowings (repayments), net	18,300	86,500	95,000
Long-term borrowings	317,000	603,500	463,605
Repayment of long-term debt	(274,070)	(303,793)	(333,066)
Proceeds from stock option exercise	1,739	7,028	5,619
Awards of common stock	(13,929)	(15,451)	(17,720)
Dividends paid	(77,792)	(70,623)	(64,251)
Valencia's transactions with its owner	(17,742)	(17,006)	(17,049)
Amounts received under transmission interconnection arrangements	11,879	7,171	27
Refunds paid under transmission interconnection arrangements	(21,290)	(2,830)	(2,338)
Other, net	(2,942)	(2,104)	(4,396)
Net cash flows from financing activities	(58,847)	242,392	175,431
Change in Cash and Cash Equivalents	(548)	(41,529)	17,777
Cash and Cash Equivalents at Beginning of Year	4,522	46,051	28,274
Cash and Cash Equivalents at End of Year	$ 3,974	$ 4,522	$ 46,051
Supplemental Cash Flow Disclosures:			
Interest paid, net of amounts capitalized	$ 120,955	$ 115,043	$ 103,382
Income taxes paid (refunded), net	$ 625	$ (307)	$ (1,890)
Supplemental schedule of noncash investing and financing activities:			
(Increase) decrease in accrued plant additions	$ (25,261)	$ 18,345	$ (19,080)
Contribution of utility plant to NMRD	$ 24,829		

The accompanying notes, as they relate to PNMR, are an integral part of these consolidated financial statements.

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PNM RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2017	**2016**
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 3,974	$ 4,522
Accounts receivable, net of allowance for uncollectible accounts of $1,081 and $1,209	90,473	87,012
Unbilled revenues	54,055	58,284
Other receivables	17,582	28,245
Current portion of Westmoreland Loan	3,576	38,360
Materials, supplies, and fuel stock	66,502	73,027
Regulatory assets	2,933	3,855
Commodity derivative instruments	1,088	5,224
Income taxes receivable	6,879	6,066
Other current assets	47,358	73,444
Total current assets	294,420	378,039
Other Property and Investments:		
Long-term portion of Westmoreland Loan	53,064	56,640
Available-for-sale securities	323,524	272,977

Equity investment in NMRD	16,510	—
Other investments	503	547
Non-utility property	3,404	3,404
Total other property and investments	397,005	333,568
Utility Plant:		
Plant in service, held for future use, and to be abandoned	7,238,285	6,944,534
Less accumulated depreciation and amortization	2,592,692	2,334,938
	4,645,593	4,609,596
Construction work in progress	245,933	208,206
Nuclear fuel, net of accumulated amortization of $43,524 and $43,905	88,701	86,913
Net utility plant	4,980,227	4,904,715
Deferred Charges and Other Assets:		
Regulatory assets	600,672	501,223
Goodwill	278,297	278,297
Commodity derivative instruments	3,556	—
Other deferred charges	91,926	75,238
Total deferred charges and other assets	974,451	854,758
	$ 6,646,103	$ 6,471,080

The accompanying notes, as they relate to PNMR, are an integral part of these consolidated financial statements.

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PNM RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2017	**2016**
	(In thousands, except share information)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Short-term debt	$ 305,400	$ 287,100
Current installments of long-term debt	256,895	273,348
Accounts payable	121,383	86,705
Customer deposits	11,028	11,374
Accrued interest and taxes	62,357	61,871
Regulatory liabilities	2,309	3,609
Commodity derivative instruments	1,182	2,339
Dividends declared	21,240	19,448
Other current liabilities	53,850	59,314
Total current liabilities	835,644	805,108
Long-term Debt, net of Unamortized Premiums, Discounts, and Debt Issuance Costs	2,180,750	2,119,364
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	547,210	940,650
Regulatory liabilities	933,578	455,649
Asset retirement obligations	146,679	127,519
Accrued pension liability and postretirement benefit cost	94,003	125,844
Commodity derivative instruments	3,556	—
Other deferred credits	131,706	140,545
Total deferred credits and other liabilities	1,856,732	1,790,207
Total liabilities	4,873,126	4,714,679
Commitments and Contingencies (See Note 16)		
Cumulative Preferred Stock of Subsidiary		
without mandatory redemption requirements ($100 stated value; 10,000,000 shares authorized; issued and outstanding 115,293 shares)	11,529	11,529
Equity:		
PNMR common stockholders' equity:		
Common stock (no par value; 120,000,000 shares authorized; issued and outstanding 79,653,624 shares)	1,157,665	1,163,661
Accumulated other comprehensive income (loss), net of income taxes	(95,940)	(92,451)

Retained earnings	633,528	604,742
Total PNMR common stockholders' equity	1,695,253	1,675,952
Non-controlling interest in Valencia	66,195	68,920
Total equity	1,761,448	1,744,872
	$ 6,646,103	$ 6,471,080

The accompanying notes, as they relate to PNMR, are an integral part of these consolidated financial statements.

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PNM RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Attributable to PNMR					
	Common Stock	AOCI	Retained Earnings	Total PNMR Common Stockholder's Equity	Non-controlling Interest in Valencia	Total Equity
	(In thousands)					
Balance at December 31, 2014	$ 1,173,845	$ (61,755)	$ 609,456	$ 1,721,546	$ 73,546	$ 1,795,092
Net earnings before subsidiary preferred stock dividends	—	—	16,168	16,168	14,910	31,078
Total other comprehensive income (loss)	—	(9,677)	—	(9,677)	—	(9,677)
Subsidiary preferred stock dividends	—	—	(528)	(528)	—	(528)
Dividends declared on common stock	—	—	(65,316)	(65,316)	—	(65,316)
Proceeds from stock option exercise	5,619	—	—	5,619	—	5,619
Awards of common stock	(17,720)	—	—	(17,720)	—	(17,720)
Excess tax (shortfall) from stock-based payment arrangements	(142)	—	—	(142)	—	(142)
Stock based compensation expense	4,863	—	—	4,863	—	4,863
Valencia's transactions with its owner	—	—	—	—	(17,049)	(17,049)
Balance at December 31, 2015	1,166,465	(71,432)	559,780	1,654,813	71,407	1,726,220
Net earnings before subsidiary preferred stock dividends	—	—	117,377	117,377	14,519	131,896
Total other comprehensive income (loss)	—	(21,019)	—	(21,019)	—	(21,019)
Subsidiary preferred stock dividends	—	—	(528)	(528)	—	(528)
Dividends declared on common stock	—	—	(71,887)	(71,887)	—	(71,887)
Proceeds from stock option exercise	7,028	—	—	7,028	—	7,028
Awards of common stock	(15,451)	—	—	(15,451)	—	(15,451)
Excess tax (shortfall) from stock-based payment arrangements	(15)	—	—	(15)	—	(15)
Stock based compensation expense	5,634	—	—	5,634	—	5,634
Valencia's transactions with its owner	—	—	—	—	(17,006)	(17,006)
Balance at December 31, 2016, as originally reported	1,163,661	(92,451)	604,742	1,675,952	68,920	1,744,872
Cumulative effect adjustment (Note 13)	—	—	10,382	10,382	—	10,382
Balance at January 1, 2017, as adjusted	1,163,661	(92,451)	615,124	1,686,334	68,920	1,755,254
Reclassification of stranded income taxes resulting from tax reform (Note 11)	—	(17,586)	17,586	—	—	—
Net earnings before subsidiary preferred stock dividends	—	—	80,402	80,402	15,017	95,419
Total other comprehensive income	—	14,097	—	14,097	—	14,097
Subsidiary preferred stock dividends	—	—	(528)	(528)	—	(528)
Dividends declared on common stock	—	—	(79,056)	(79,056)	—	(79,056)
Proceeds from stock option exercise	1,739	—	—	1,739	—	1,739
Awards of common stock	(13,929)	—	—	(13,929)	—	(13,929)
Stock based compensation expense	6,194	—	—	6,194	—	6,194
Valencia's transactions with its owner	—	—	—	—	(17,742)	(17,742)
Balance at December 31, 2017	$ 1,157,665	$ (95,940)	$ 633,528	$ 1,695,253	$ 66,195	$ 1,761,448

The accompanying notes, as they relate to PNMR, are an integral part of these consolidated financial statements.

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PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES
A WHOLLY-OWNED SUBSIDIARY OF PNM RESOURCES, INC.
CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Electric Operating Revenues	$ 1,104,230	$ 1,035,913	$ 1,131,195
Operating Expenses:			
Cost of energy	321,677	299,714	391,131
Administrative and general	172,446	169,209	161,953
Energy production costs	137,450	146,187	176,752
Regulatory disallowances and restructuring costs	27,036	15,011	167,471
Depreciation and amortization	147,017	133,447	115,717
Transmission and distribution costs	42,370	39,657	43,642
Taxes other than income taxes	43,709	44,598	41,149
Total operating expenses	891,705	847,823	1,097,815
Operating income	212,525	188,090	33,380
Other Income and Deductions:			
Interest income	8,454	10,173	6,574
Gains on available-for-sale securities	27,161	19,517	16,060
Other income	13,527	12,088	19,347
Other (deductions)	(10,002)	(9,539)	(8,493)
Net other income and deductions	39,140	32,239	33,488
Interest Charges	82,697	87,469	79,950
Earnings (Loss) before Income Taxes	168,968	132,860	(13,082)
Income Taxes (Benefit)	81,555	40,922	(12,758)
Net Earnings (Loss)	87,413	91,938	(324)
(Earnings) Attributable to Valencia Non-controlling Interest	(15,017)	(14,519)	(14,910)
Net Earnings (Loss) Attributable to PNM	72,396	77,419	(15,234)
Preferred Stock Dividends Requirements	(528)	(528)	(528)
Net Earnings (Loss) Available for PNM Common Stock	$ 71,868	$ 76,891	$ (15,762)

The accompanying notes, as they relate to PNM, are an integral part of these consolidated financial statements.

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PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES
A WHOLLY-OWNED SUBSIDIARY OF PNM RESOURCES, INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Net Earnings (Loss)	$ 87,413	$ 91,938	$ (324)
Other Comprehensive Income (Loss):			
Unrealized Gains on Available-for-Sale Securities:			
Unrealized holding gains arising during the period, net of income tax (expense) of $(10,927), $(304), and $(4,310)	17,233	474	6,688
Reclassification adjustment for (gains) included in net earnings, net of income tax expense of $6,816, $8,639, and $11,181	(10,751)	(13,500)	(17,350)
Pension Liability Adjustment:			
Experience gains (losses), net of income tax (expense) benefit of $(919), $7,219, and $1,726	2,699	(11,282)	(2,679)
Reclassification adjustment for amortization of experience (gains) losses recognized as net periodic benefit cost, net of income tax expense (benefit) of $(2,504), $(2,148), and $(2,332)	3,948	3,356	3,620
Total Other Comprehensive Income (Loss)	13,129	(20,952)	(9,721)
Comprehensive Income (Loss)	100,542	70,986	(10,045)
Comprehensive (Income) Attributable to Valencia Non-controlling Interest	(15,017)	(14,519)	(14,910)
Comprehensive Income (Loss) Attributable to PNM	$ 85,525	$ 56,467	$ (24,955)

The accompanying notes, as they relate to PNM, are an integral part of these consolidated financial statements.

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PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES
A WHOLLY-OWNED SUBSIDIARY OF PNM RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017	**2016**	**2015**
		(In thousands)	
Cash Flows From Operating Activities:			
Net earnings (loss)	$ 87,413	$ 91,938	$ (324)
Adjustments to reconcile net earnings to net cash flows from operating activities:			
Depreciation and amortization	180,500	166,047	150,538
Deferred income tax expense	82,549	53,119	(2,836)
Net unrealized (gains) losses on commodity derivatives	2,875	1,577	5,188
Realized (gains) on available-for-sale securities	(27,161)	(19,517)	(16,060)
Regulatory disallowances and restructuring costs	27,036	15,011	167,471
Allowance for equity funds used during construction	(8,664)	(4,163)	(10,430)
Other, net	2,615	3,046	2,794
Changes in certain assets and liabilities:			
Accounts receivable and unbilled revenues	(419)	4,769	(2,515)
Materials, supplies, and fuel stock	3,542	(3,924)	381
Other current assets	32,775	1,127	23,693
Other assets	15,121	(23,880)	4,194
Accounts payable	9,736	5,614	(31,139)
Accrued interest and taxes	21,523	(9,601)	(5,343)
Other current liabilities	(11,099)	(12,136)	(275)
Other liabilities	(9,389)	20,119	(33,503)
Net cash flows from operating activities	408,953	289,146	251,834
Cash Flows From Investing Activities:			
Utility plant additions	(309,142)	(445,464)	(404,840)
Proceeds from sales of available-for-sale securities	637,492	522,601	252,174
Purchases of available-for-sale securities	(650,284)	(538,383)	(262,548)
Return of principal on PVNGS lessor notes	—	8,547	21,694
Other, net	33	171	2,935
Net cash flows from investing activities	(321,901)	(452,528)	(390,585)

The accompanying notes, as they relate to PNM, are an integral part of these consolidated financial statements.

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PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES
A WHOLLY-OWNED SUBSIDIARY OF PNM RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31,		
	2017	**2016**	**2015**
		(In thousands)	
Cash Flows From Financing Activities:			
Short-term borrowings (repayments), net	(21,200)	61,000	—
Long-term borrowings	257,000	321,000	313,605
Repayment of long-term debt	(232,000)	(271,000)	(214,300)
Equity contribution from parent	—	28,142	175,000
Valencia's transactions with its owner	(17,742)	(17,006)	(17,049)
Dividends paid	(61,223)	(4,670)	(94,968)
Amounts received under transmission interconnection arrangements	11,879	7,171	27
Refunds paid under transmission interconnection arrangements	(21,290)	(2,830)	(2,338)
Other, net	(1,692)	(1,239)	(3,568)
Net cash flows from financing activities	(86,268)	120,568	156,409
Change in Cash and Cash Equivalents	784	(42,814)	17,658
Cash and Cash Equivalents at Beginning of Year	324	43,138	25,480
Cash and Cash Equivalents at End of Year	$ 1,108	$ 324	$ 43,138

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Supplemental Cash Flow Disclosures:			
Interest paid, net of amounts capitalized	$ 77,960	$ 82,514	$ 69,936
Income taxes paid (refunded), net	$ (23,391)	$ (967)	$ (1,450)
Supplemental schedule of noncash investing activities:			
(Increase) decrease in accrued plant additions	$ (11,792)	$ 22,433	$ (17,469)

The accompanying notes, as they relate to PNM, are an integral part of these consolidated financial statements.

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PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES
A WHOLLY-OWNED SUBSIDIARY OF PNM RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2017	**2016**
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,108	$ 324
Accounts receivable, net of allowance for uncollectible accounts of $1,081 and $1,209	67,227	65,003
Unbilled revenues	43,869	48,289
Other receivables	14,541	25,514
Affiliate receivables	9,486	8,886
Materials, supplies, and fuel stock	60,859	64,401
Regulatory assets	2,139	3,442
Commodity derivative instruments	1,088	5,224
Income taxes receivable	3,410	25,807
Other current assets	39,904	67,355
Total current assets	243,631	314,245
Other Property and Investments:		
Available-for-sale securities	323,524	272,977
Other investments	283	316
Non-utility property	96	96
Total other property and investments	323,903	273,389
Utility Plant:		
Plant in service, held for future use, and to be abandoned	5,501,070	5,359,211
Less accumulated depreciation and amortization	2,029,534	1,809,528
	3,471,536	3,549,683
Construction work in progress	204,079	158,122
Nuclear fuel, net of accumulated amortization of $43,524 and $43,905	88,701	86,913
Net utility plant	3,764,316	3,794,718
Deferred Charges and Other Assets:		
Regulatory assets	459,239	365,413
Goodwill	51,632	51,632
Commodity derivative instruments	3,556	—
Other deferred charges	75,286	68,149
Total deferred charges and other assets	589,713	485,194
	$ 4,921,563	$ 4,867,546

The accompanying notes, as they relate to PNM, are an integral part of these consolidated financial statements.

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES
A WHOLLY-OWNED SUBSIDIARY OF PNM RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2017	December 31, 2016
	(In thousands, except share information)	
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current Liabilities:		
Short-term debt	$ 39,800	$ 61,000
Current installments of long-term debt	23	231,880
Accounts payable	77,094	55,566
Affiliate payables	22,875	23,183
Customer deposits	11,028	11,374
Accrued interest and taxes	33,945	34,819
Regulatory liabilities	784	3,517
Commodity derivative instruments	1,182	2,339
Dividends declared	132	132
Other current liabilities	31,633	33,551
Total current liabilities	218,496	457,361
Long-term Debt, net of Unamortized Premiums, Discounts, and Debt Issuance Costs	1,657,887	1,399,489
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	449,012	748,666
Regulatory liabilities	754,441	423,701
Asset retirement obligations	145,707	126,601
Accrued pension liability and postretirement benefit cost	86,124	114,427
Commodity derivative instruments	3,556	—
Other deferred credits	106,442	118,980
Total deferred credits and liabilities	1,545,282	1,532,375
Total liabilities	3,421,665	3,389,225
Commitments and Contingencies (See Note 16)		
Cumulative Preferred Stock		
without mandatory redemption requirements ($100 stated value; 10,000,000 shares authorized; issued and outstanding 115,293 shares)	11,529	11,529
Equity:		
PNM common stockholder's equity:		
Common stock (no par value; 40,000,000 shares authorized; issued and outstanding 39,117,799 shares)	1,264,918	1,264,918
Accumulated other comprehensive income (loss), net of income taxes	(97,093)	(92,428)
Retained earnings	254,349	225,382
Total PNM common stockholder's equity	1,422,174	1,397,872
Non-controlling interest in Valencia	66,195	68,920
Total equity	1,488,369	1,466,792
	$ 4,921,563	$ 4,867,546

The accompanying notes, as they relate to PNM, are an integral part of these consolidated financial statements.

PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES
A WHOLLY-OWNED SUBSIDIARY OF PNM RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Attributable to PNM					
	Common Stock	AOCI	Retained Earnings	Total PNM Common Stockholder's Equity	Non-controlling Interest in Valencia	Total Equity
	(In thousands)					
Balance at December 31, 2014	$ 1,061,776	$ (61,755)	$ 262,835	$ 1,262,856	$ 73,546	$ 1,336,402
Net earnings (loss)	—	—	(15,234)	(15,234)	14,910	(324)
Total other comprehensive income (loss)	—	(9,721)	—	(9,721)	—	(9,721)

Dividends declared on preferred stock	—	—	(528)	(528)	—	(528)
Equity contribution from parent	175,000	—	—	175,000	—	175,000
Dividends declared on common stock	—	—	(94,440)	(94,440)	—	(94,440)
Valencia's transactions with its owner	—	—	—	—	(17,049)	(17,049)
Balance at December 31, 2015	1,236,776	(71,476)	152,633	1,317,933	71,407	1,389,340
Net earnings	—	—	77,419	77,419	14,519	91,938
Total other comprehensive income (loss)	—	(20,952)	—	(20,952)	—	(20,952)
Dividends declared on preferred stock	—	—	(528)	(528)	—	(528)
Equity contributions from parent	28,142	—	—	28,142	—	28,142
Dividends declared on common stock	—	—	(4,142)	(4,142)	—	(4,142)
Valencia's transactions with its owner	—	—	—	—	(17,006)	(17,006)
Balance at December 31, 2016	1,264,918	(92,428)	225,382	1,397,872	68,920	1,466,792
Reclassification of stranded income taxes resulting from tax reform (Note 11)	—	(17,794)	17,794	—	—	—
Net earnings	—	—	72,396	72,396	15,017	87,413
Total other comprehensive income	—	13,129	—	13,129	—	13,129
Dividends declared on preferred stock	—	—	(528)	(528)	—	(528)
Dividends declared on common stock	—	—	(60,695)	(60,695)	—	(60,695)
Valencia's transactions with its owner	—	—	—	—	(17,742)	(17,742)
Balance at December 31, 2017	$ 1,264,918	$ (97,093)	$ 254,349	$ 1,422,174	$ 66,195	$ 1,488,369

The accompanying notes, as they relate to PNM, are an integral part of these consolidated financial statements.

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TEXAS-NEW MEXICO POWER COMPANY AND SUBSIDIARIES
A WHOLLY-OWNED SUBSIDIARY OF PNM RESOURCES, INC.
CONSOLIDATED STATEMENTS OF EARNINGS

	Year Ended December 31,		
	2017	**2016**	**2015**
	(In thousands)		
Electric Operating Revenues	$ 340,773	$ 327,038	$ 307,887
Operating Expenses:			
Cost of energy	85,802	80,882	73,518
Administrative and general	39,828	39,423	36,755
Depreciation and amortization	63,146	61,126	56,285
Transmission and distribution costs	29,206	26,570	25,515
Taxes other than income taxes	29,187	27,396	25,781
Total operating expenses	247,169	235,397	217,854
Operating income	93,604	91,641	90,033
Other Income and Deductions:			
Other income	4,994	4,629	4,240
Other (deductions)	(1,443)	(1,427)	(504)
Net other income and deductions	3,551	3,202	3,736
Interest Charges	30,084	29,335	27,681
Earnings before Income Taxes	67,071	65,508	66,088
Income Taxes	31,512	23,836	24,125
Net Earnings	$ 35,559	$ 41,672	$ 41,963

The accompanying notes, as they relate to TNMP, are an integral part of these consolidated financial statements.

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TEXAS-NEW MEXICO POWER COMPANY AND SUBSIDIARIES
A WHOLLY-OWNED SUBSIDIARY OF PNM RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Cash Flows From Operating Activities:			
Net earnings	$ 35,559	$ 41,672	$ 41,963
Adjustments to reconcile net earnings to net cash flows from operating activities:			
Depreciation and amortization	64,939	62,866	57,909
Deferred income tax expense	27,275	12,662	20,883
Allowance for equity funds used during construction and other, net	(1,120)	(772)	18
Changes in certain assets and liabilities:			
Accounts receivable and unbilled revenues	(1,427)	(2,226)	(783)
Materials and supplies	(2,069)	(245)	(561)
Other current assets	(1,253)	(621)	3,928
Other assets	(20,967)	(19,126)	(2,310)
Accounts payable	2,419	(2,040)	(1,782)
Accrued interest and taxes	(15,962)	12,690	4,317
Other current liabilities	(2,236)	298	1,019
Other liabilities	1,334	6,822	(9,823)
Net cash flows from operating activities	86,492	111,980	114,778
Cash Flows From Investing Activities:			
Utility plant additions	(145,495)	(122,518)	(124,584)
Net cash flows from investing activities	(145,495)	(122,518)	(124,584)

The accompanying notes, as they relate to TNMP, are an integral part of these consolidated financial statements.

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S&P Global Market Intelligence

TEXAS-NEW MEXICO POWER COMPANY AND SUBSIDIARIES
A WHOLLY-OWNED SUBSIDIARY OF PNM RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Cash Flow From Financing Activities:			
Short-term borrowings (repayments), net	—	(59,000)	54,000
Short-term borrowings (repayments) – affiliate, net	(4,600)	(7,200)	(10,900)
Long-term borrowings	60,000	60,000	—
Equity contribution from parent	50,000	50,000	—
Dividends paid	(44,389)	(31,817)	(33,248)
Other, net	(979)	(775)	(46)
Net cash flows from financing activities	60,032	11,208	9,806
Change in Cash and Cash Equivalents	1,029	670	—
Cash and Cash Equivalents at Beginning of Year	671	1	1
Cash and Cash Equivalents at End of Year	$ 1,700	$ 671	$ 1
Supplemental Cash Flow Disclosures:			
Interest paid, net of amounts capitalized	$ 29,251	$ 26,766	$ 26,216
Income taxes paid, (refunded) net	$ 21,436	$ 660	$ 290
Supplemental schedule of noncash investing and financing activities:			
(Increase) decrease in accrued plant additions	$ (15,737)	$ (1,271)	$ (5)

The accompanying notes, as they relate to TNMP, are an integral part of these consolidated financial statements.

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TEXAS-NEW MEXICO POWER COMPANY AND SUBSIDIARIES
A WHOLLY-OWNED SUBSIDIARY OF PNM RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

	December 31,	
	2017	2016
	(In thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,700	$ 671
Accounts receivable	23,246	22,009
Unbilled revenues	10,186	9,995
Other receivables	2,860	2,090
Affiliate receivables	336	—
Materials and supplies	5,643	8,626
Regulatory assets	794	413
Other current assets	1,131	1,031
Total current assets	45,896	44,835
Other Property and Investments:		
Other investments	220	231
Non-utility property	2,240	2,240
Total other property and investments	2,460	2,471
Utility Plant:		
Plant in service and plant held for future use	1,504,778	1,380,584
Less accumulated depreciation and amortization	460,858	429,397
	1,043,920	951,187
Construction work in progress	34,350	16,978
Net utility plant	1,078,270	968,165
Deferred Charges and Other Assets:		
Regulatory assets	141,433	135,810
Goodwill	226,665	226,665
Other deferred charges	6,046	5,277
Total deferred charges and other assets	374,144	367,752
	$ 1,500,770	$ 1,383,223

The accompanying notes, as they relate to TNMP, are an integral part of these consolidated financial statements.

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TEXAS-NEW MEXICO POWER COMPANY AND SUBSIDIARIES
A WHOLLY-OWNED SUBSIDIARY OF PNM RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2017	2016
	(In thousands, except share information)	
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current Liabilities:		
Short-term debt – affiliate	$ —	$ 4,600
Accounts payable	29,812	16,709
Affiliate payables	667	3,793
Accrued interest and taxes	29,619	45,581
Regulatory liabilities	1,525	92
Other current liabilities	2,450	2,134
Total current liabilities	64,073	72,909
Long-term Debt, net of Unamortized Premiums, Discounts, and Debt Issuance Costs	480,620	420,875
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	126,415	245,785
Regulatory liabilities	179,137	31,948
Asset retirement obligations	793	754
Accrued pension liability and postretirement benefit cost	7,879	11,417
Other deferred credits	7,448	6,300
Total deferred credits and other liabilities	321,672	296,204
Total liabilities	866,365	789,988
Commitments and Contingencies (See Note 16)		

Common Stockholder's Equity:		
Common stock ($10 par value; 12,000,000 shares authorized; issued and outstanding 6,358 shares)	64	64
Paid-in-capital	504,166	454,166
Retained earnings	130,175	139,005
Total common stockholder's equity	634,405	593,235
	$ 1,500,770	$ 1,383,223

The accompanying notes, as they relate to TNMP, are an integral part of these consolidated financial statements.

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TEXAS-NEW MEXICO POWER COMPANY AND SUBSIDIARIES
A WHOLLY-OWNED SUBSIDIARY OF PNM RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCKHOLDER'S EQUITY

	Common Stock	Paid-in Capital	Retained Earnings	Total Common Stockholder's Equity
		(In thousands)		
Balance at December 31, 2014	$ 64	$ 404,166	$ 120,435	$ 524,665
Net earnings	—	—	41,963	41,963
Dividends declared on common stock	—	—	(33,248)	(33,248)
Balance at December 31, 2015	64	404,166	129,150	533,380
Net earnings	—	—	41,672	41,672
Equity contributions from parent	—	50,000	—	50,000
Dividends declared on common stock	—	—	(31,817)	(31,817)
Balance at December 31, 2016	64	454,166	139,005	593,235
Net earnings	—	—	35,559	35,559
Equity contributions from parent	—	50,000	—	50,000
Dividends declared on common stock	—	—	(44,389)	(44,389)
Balance at December 31, 2017	$ 64	$ 504,166	$ 130,175	$ 634,405

The accompanying notes, as they relate to TNMP, are an integral part of these consolidated financial statements.

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PNM RESOURCES, INC. AND SUBSIDIARIES
PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES
TEXAS-NEW MEXICO POWER COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2017, 2016 and 2015

(1) Summary of the Business and Significant Accounting Policies

Nature of Business

PNMR is an investor-owned holding company of energy and energy-related businesses. PNMR's primary subsidiaries are PNM and TNMP. PNM is a public utility with regulated operations primarily engaged in the generation, transmission, and distribution of electricity. TNMP is a wholly-owned subsidiary of TNP, which is a holding company that is wholly-owned by PNMR. TNMP provides regulated transmission and distribution services in Texas. PNMR's common stock trades on the New York Stock Exchange under the symbol PNM.

Financial Statement Preparation and Presentation

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could ultimately differ from those estimated.

The Notes to Consolidated Financial Statements include disclosures for PNMR, PNM, and TNMP. For discussion purposes, this report uses the term "Company" when discussing matters of common applicability to PNMR, PNM, and TNMP. Discussions regarding only PNMR, PNM, or TNMP are so indicated.

Certain amounts in the 2016 and 2015 Consolidated Financial Statements and Notes thereto have been reclassified to conform to the 2017 financial statement presentation.

GAAP defines subsequent events as events or transactions that occur after the balance sheet date but before financial statements are issued or are available to be issued. Based on their nature, magnitude, and timing, certain subsequent events may be required to be reflected at the balance sheet date and/or required to be disclosed in the financial statements. The Company has evaluated subsequent events as required by GAAP.

Principles of Consolidation

The Consolidated Financial Statements of each of PNMR, PNM, and TNMP include their accounts and those of subsidiaries in which that entity owns a majority voting interest. PNM also consolidates Valencia (Note 9) and, through January 15, 2016, the PVNGS Capital Trust. PNM owns undivided interests in several jointly-owned power plants and records its pro-rata share of the assets, liabilities, and expenses for those plants. The agreements for the jointly-owned plants provide that if an owner were to default on its payment obligations, the non-defaulting owners would be responsible for their proportionate share of the obligations of the defaulting owner. In exchange, the non-defaulting owners would be entitled to their

proportionate share of the generating capacity of the defaulting owner. There have been no such payment defaults under any of the agreements for the jointly-owned plants.

PNMR shared services' administrative and general expenses, which represent costs that are primarily driven by corporate level activities, are charged to the business segments. These services are billed at cost. Other significant intercompany transactions between PNMR, PNM, and TNMP include interest and income tax sharing payments, as well as equity transactions. All intercompany transactions and balances have been eliminated. See Note 3.

Accounting for the Effects of Certain Types of Regulation

The Company maintains its accounting records in accordance with the uniform system of accounts prescribed by FERC and adopted by the NMPRC and PUCT.

Certain of the Company's operations are regulated by the NMPRC, PUCT, and FERC and the provisions of GAAP for rate-regulated enterprises are applied to the regulated operations. Regulators may assign costs to accounting periods that differ from accounting methods applied by non-regulated utilities. When it is probable that regulators will permit recovery of costs through future rates, costs are deferred as regulatory assets that otherwise would be expensed. Likewise, regulatory liabilities are recognized when it is probable that regulators will require refunds through future rates or when revenue is collected for expenditures that have not yet been incurred. GAAP also provides for the recognition of revenue and regulatory assets and liabilities associated

with "alternative revenue programs" authorized by regulators. Such programs allow the utility to adjust future rates in response to past activities or completed events, if certain criteria are met, even for programs that do not otherwise qualify for recognition of regulatory assets and liabilities. Regulatory assets and liabilities are amortized into earnings over the authorized recovery period. Accordingly, the Company has deferred certain costs and recorded certain liabilities pursuant to the rate actions of the NMPRC, PUCT, and FERC. Information on regulatory assets and regulatory liabilities is contained in Note 4.

In some circumstances, regulators allow a requested increase in rates to be implemented, subject to refund, before the regulatory process has been completed and a decision rendered by the regulator. When this occurs, the Company assesses the possible outcomes of the rate proceeding. The Company records a provision for refund to the extent the amounts being collected, subject to refund, exceed the amount the Company determines is probable of ultimately being allowed by the regulator.

In connection with the adoption of Senate Bill 7 by the Texas Legislature in 1999 that deregulated electric utilities operating within ERCOT, TNMP was allowed to recover its stranded costs through the CTC and to recover a carrying charge on the CTC. The amounts yet to be collected are recorded as regulatory assets by TNMP. TNMP's calculation of allowable carrying charges on stranded costs recoverable from its transmission and distribution customers is based on a Texas Supreme Court ruling and the PUCT's application of that ruling. TNMP estimates the CTC will be fully recovered in November 2020.

Cash and Cash Equivalents

Investments in highly liquid investments with original maturities of three months or less at the date of purchase are considered cash equivalents. See New Accounting Pronouncements below.

Utility Plant

Utility plant is stated at original cost, which includes capitalized payroll-related costs such as taxes, pension, other fringe benefits, administrative costs, and AFUDC, where authorized by rate regulation, or capitalized interest.

Repairs, including major maintenance activities, and minor replacements of property are expensed when incurred, except as required by regulators for ratemaking purposes. Major replacements are charged to utility plant. Gains, losses, and costs to remove resulting from retirements or other dispositions of regulated property in the normal course of business are credited or charged to accumulated depreciation.

PNM and TNMP may receive reimbursements, referred to as contributions in aid of construction ("CIAC"), from customers to pay for all or part of certain construction projects to extent that project does not benefit regulated customers in general. PNM and TNMP account for these reimbursements as offsets to utility plant additions based on the requirements of the NMPRC, FERC, and PUCT. Due to the PUCT's regulatory treatment of CIAC reimbursements, TNMP also receives a financing component that is recognized as other income on the Consolidated Statements of Earnings. Under the NMPRC regulatory treatment, PNM does not receive a financing component.

Depreciation and Amortization

PNM's provision for depreciation and amortization of utility plant, other than nuclear fuel, is based upon straight-line rates approved by the NMPRC and FERC. Amortization of nuclear fuel is based on units-of-production. TNMP's provision for depreciation and amortization of utility plant is based upon straight-line rates approved by the PUCT. Depreciation of non-utility property is computed based on the straight-line method. The provision for depreciation of certain equipment is allocated between operating expenses and construction projects based on the use of the equipment. Average straight-line rates used were as follows:

	Year ended December 31		
	2017	2016	2015
PNM			
Electric plant	2.52%	2.33%	2.27%
Common, intangible, and general plant	8.36%	5.40%	4.66%
TNMP	3.57%	3.66%	3.65%

Allowance for Funds Used During Construction

As provided by the FERC uniform systems of accounts, AFUDC is charged to regulated utility plant for construction projects. This allowance is designed to enable a utility to capitalize financing costs during periods of construction of property subject to rate regulation. It represents the cost of borrowed funds (allowance for borrowed funds used during construction or "debt AFUDC") and a return on other funds (allowance for equity funds used during construction or "equity AFUDC"). The debt AFUDC is recorded in interest charges and the equity AFUDC is recorded in other income on the Consolidated Statements of Earnings.

For the years ended December 31, 2017, 2016, and 2015, PNM recorded $6.3 million, $5.3 million, and $7.8 million of debt AFUDC and $8.7 million, $4.2 million, and $10.4 million of equity AFUDC. TNMP recorded $1.2 million, $0.9 million, and $0.5 million of debt AFUDC and $0.9 million, $0.8 million, and zero of equity AFUDC.

Capitalized Interest

The Company capitalizes interest on its construction projects and major computer software projects not subject to the computation of AFUDC. Capitalized interest is recorded in interest charges. Interest was capitalized at the overall weighted average borrowing rate of 5.9%, 6.1%, and 6.6% for 2017, 2016, and 2015. In 2017, 2016, and 2015, capitalized interest was $1.3 million, $1.8 million, and $1.5 million for PNMR consolidated; $0.6 million, $0.8 million, and $0.8 million for PNM; and less than $0.1 million, $0.1 million, and $0.1 million for TNMP.

Materials, Supplies, and Fuel Stock

Materials and supplies relate to transmission, distribution, and generating assets. Materials and supplies are charged to inventory when purchased and are expensed or capitalized as appropriate when issued. Materials and supplies are valued using an average costing method. Coal is valued using a rolling weighted average costing method that is updated based on the current period cost per ton. Periodic aerial surveys are performed on the coal piles and adjustments are made. Average cost is equal to net realizable value under the ratemaking process.

Inventories consisted of the following at December 31:

	PNMR		PNM		TNMP	
	2017	2016	2017	2016	2017	2016
	(In thousands)					
Coal	$ 16,714	$ 19,940	$ 16,714	$ 19,940	$ —	$ —
Materials and supplies	49,788	53,087	44,145	44,461	5,643	8,626
	$ 66,502	$ 73,027	$ 60,859	$ 64,401	$ 5,643	$ 8,626

Investments

In 1985 and 1986, PNM entered into eleven operating leases for interests in certain PVNGS generation facilities (Note 7). The 10.3% and 10.15% lessor notes that were issued by the owners of the assets subject to these leases were subsequently purchased and held by the PVNGS Capital Trust, which was consolidated by PNM. The PVNGS Capital Trust held certain of the lessor notes to their maturities in January 2015 and January 2016. Upon final maturity of the lessor notes, the PVNGS Capital Trust ceased to exist. The PVNGS lessor notes were carried at amortized cost.

PNM holds investment securities in the NDT for the purpose of funding its share of the decommissioning costs of PVNGS and trusts for PNM's share of final reclamation costs related to the coal mines serving SJGS and Four Corners (Note 16). All of these investments are classified as available-for-sale. PNM evaluates the securities for impairment on an on-going basis. Since third party investment managers have sole discretion over the purchase and sales of the securities, PNM records a realized loss as an impairment for any security that has a market value that is less than cost at the end of each quarter. For the years ended December 31, 2017, 2016, and 2015, PNM recorded impairment losses on the available-for-sale securities held in the NDT and coal mine reclamation trusts of $7.1 million, $13.9 million, and $10.4 million. No gains or losses are deferred as regulatory assets or liabilities. Through December 31, 2017, unrealized gains on these investments, net of related tax effects, are included in OCI and AOCI. The available-for-sale securities are primarily comprised of international, United States, state, and municipal government obligations and corporate debt and equity securities. All investments are held in PNM's name and are in the custody

of major financial institutions. The specific identification method is used to determine the cost of securities disposed of, with realized gains and losses reflected in other income and deductions. See New Accounting Pronouncements below.

Investment in NM Renewable Development, LLC

On September 22, 2017, PNMR Development and AEP OnSite Partners created NMRD to pursue the acquisition, development, and ownership of renewable energy generation projects, primarily in the state of New Mexico. PNMR Development and AEP OnSite Partners each have a 50% ownership interest in NMRD. In December 2017, PNMR Development made a contribution to NMRD of its interest in three 10 MW solar facilities it was constructing and assigned its interests in several agreements related to those facilities to NMRD. The facilities had a book value of $24.8 million, which approximated fair value at that time. AEP OnSite Partners made a cash contribution to NMRD equal to 50% of the value of the 30 MW solar capacity, amounting to $12.4 million, which cash was then distributed from NMRD to PNMR Development. During 2017, PNMR Development and AEP OnSite Partners each made cash contributions of $4.1 million to NMRD for its construction activities. At December 31, 2017, NMRD's renewable energy capacity under contract is 31.8 MW, which includes 11.8 MW of solar PV facilities in operation, consisting of 10 MW required to supply energy to a new data center in PNM's service territory (Note 17) and 1.8 MW to supply energy to Columbus Electric Cooperative located in southwest New Mexico, and 20 MW of solar PV under construction. PNMR accounts for its investment in NMRD using the equity method of accounting because PNMR's ownership interest results in significant influence, but not control, over NMRD and its operations. PNMR records as income its percentage share of earnings or loss of NMRD and carries its investment at cost, adjusted for its share of undistributed earnings or losses.

For the year ended December 31, 2017, NMRD revenues, expenses, and net income were each less than $0.1 million. At December 31, 2017, NMRD had $6.0 million in cash, $30.9 million of property, plant, and equipment, $3.9 million in accounts payable, and $33.0 million of owners' equity. NMRD anticipates it will complete the remaining 20 MW of solar PV facilities under construction by mid-2018, which is anticipated to be funded by additional equity contributions.

Goodwill

Under GAAP, the Company does not amortize goodwill. Goodwill is evaluated for impairment annually, or more frequently if events and circumstances indicate that the goodwill might be impaired. See Note 18.

Asset Impairment

Tangible long-lived assets are evaluated in relation to the estimated future undiscounted cash flows to assess recoverability when events and circumstances indicate that the assets might be impaired.

Revenue Recognition

Electric operating revenues are recorded in the period of energy delivery, which includes estimated amounts for service rendered but unbilled at the end of each accounting period. The determination of the energy sales billed to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading and the corresponding unbilled revenue are estimated. Unbilled electric revenue is estimated based on the daily generation volumes, estimated customer usage by class, line losses, and applicable customer rates reflecting historical trends and experience.

PNM's wholesale electricity sales are recorded as electric operating revenues and the wholesale electricity purchases are recorded as costs of energy sold. In accordance with GAAP, derivative contracts that are subject to unplanned netting are recorded net in earnings. A "book-out" is the planned or unplanned netting of off-setting purchase and sale transactions. A book-out is a transmission mechanism to reduce congestion on the transmission system or administrative burden. For accounting purposes, a book-out is the recording of net revenues upon the settlement of a derivative contract.

Unrealized gains and losses on contracts that are not designated for hedge accounting are classified as economic hedges. Economic hedges are defined as derivative instruments, including long-term power and fuel supply agreements, used to hedge generation assets and purchased power costs. Changes in the fair value of economic hedges are reflected in results of operations, with changes related to economic hedges on sales included in operating revenues and changes related to economic hedges on purchases included in cost of energy sold.

See New Accounting Pronouncements below.

Accounts Receivable and Allowance for Uncollectible Accounts

Accounts receivable consists primarily of trade receivables from customers. In the normal course of business, credit is extended to customers on a short-term basis. The Company calculates the allowance for uncollectible accounts based on historical experience and estimated default rates. The accounts receivable balances are reviewed monthly and adjustments to the allowance for uncollectible accounts and bad debt expense are made as necessary. Amounts that are deemed uncollectible are written off.

Amortization of Debt Acquisition Costs

Discount, premium, and expense related to the issuance of long-term debt are amortized over the lives of the respective issues. Gains and losses incurred upon the early retirement of long-term debt are recognized in other income or other deductions, except for amounts recoverable through NMPRC, FERC, or PUCT regulation, which are recorded as regulatory assets or liabilities and amortized over the lives of the respective issues. Unamortized debt premium, discount, and expense related to long-term are reflected as part of the debt liabilities on the Consolidated Balance Sheets.

Derivatives

The Company records derivative instruments, including energy contracts, on the balance sheet as either an asset or liability measured at their fair value. GAAP requires that changes in the derivatives' fair value be recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying hedges, an entity must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. GAAP provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of AOCI and be reclassified into earnings in the period during which the hedged forecasted transaction affects earnings. The results of hedge ineffectiveness and the portion of the change in fair value of a derivative that an entity has chosen to exclude from hedge effectiveness are required to be presented in current earnings. See Note 6 and Note 8.

The Company treats all forward commodity purchases and sales contracts subject to unplanned netting or book-out by the transmission provider as derivative instruments subject to mark-to-market accounting. GAAP provides guidance on whether realized gains and losses on derivative contracts not held for trading purposes should be reported on a net or gross basis and concludes such classification is a matter of judgment that depends on the relevant facts and circumstances.

Decommissioning and Reclamation Costs

PNM owns and leases nuclear and fossil-fuel generating facilities. In accordance with GAAP, PNM is only required to recognize and measure decommissioning liabilities for tangible long-lived assets for which a legal obligation exists. Nuclear decommissioning costs and related accruals are based on periodic site-specific estimates of the costs for removing all radioactive and other structures at PVNGS and are dependent upon numerous assumptions, including estimates of future decommissioning costs at current price levels, inflation rates, and discount rates. PNM's accruals for PVNGS Units 1, 2, and 3, including portions held under leases, have been made based on such estimates, the guidelines of the NRC, and the extended PVNGS license periods. PVNGS Units 1 and 2 are included in PNM's retail rates and PVNGS Unit 3 was excluded through December 31, 2017, but is included beginning in 2018. See Note 15 and Note 16. See Note 17 for information concerning the treatment of nuclear decommissioning for the leased portions of PVNGS in the NMPRC's order in PNM's NM 2015 Rate Case and PNM's appeal of that order.

In connection with both the SJGS and Four Corners coal supply agreements, the owners are required to reimburse the mining companies for the cost of contemporaneous reclamation, as well as the costs for final reclamation of the coal mines. The reclamation costs are based on periodic site-specific studies that estimate the costs to be incurred in the future and are dependent upon numerous assumptions, including estimates of future reclamation costs at current price levels, inflation rates, and discount rates. PNM considers the contemporaneous reclamation costs part of the cost of its delivered coal costs. See Note 16 for a discussion of reclamation costs.

Environmental Costs

The normal operations of the Company involve activities and substances that expose the Company to potential liabilities under laws and regulations protecting the environment. Liabilities under these laws and regulations can be material and in some

instances may be imposed without regard to fault, or may be imposed for past acts, even though the past acts may have been lawful at the time they occurred.

The Company records its environmental liabilities when site assessments or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. The Company reviews its sites and measures the liability by assessing a range of reasonably likely costs for each identified site using currently available information and the probable level of involvement and financial condition of other potentially responsible parties. These estimates are based on assumptions regarding the costs for site investigations, remediation, operations and maintenance, monitoring, and site closure. The ultimate cost to clean up the Company's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process. Amounts recorded for environmental expense in the years ended December 31, 2017, 2016, and 2015, as well as the amounts of environmental liabilities at December 31, 2017 and 2016 were insignificant.

Pension and Other Postretirement Benefits

See Note 12 for a discussion of pension and postretirement benefits expense, including a discussion of the actuarial assumptions.

Stock-Based Compensation

See Note 13 for a discussion of stock-based compensation expense.

Income Taxes

Income taxes are recognized using the asset and liability method of accounting for income taxes. Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying value of existing assets and liabilities and their respective tax basis. In accordance with GAAP, all deferred taxes are reflected as non-current on the Consolidated Balance Sheets. Current NMPRC, FERC, and PUCT approved rates include the tax effects of the majority of these differences. GAAP requires that rate-regulated enterprises record deferred income taxes for temporary differences accorded flow-through treatment at the direction of a regulatory commission. The resulting deferred tax assets and liabilities are recorded based on the expected cash flow to be reflected in future rates. Because the NMPRC, FERC, and the PUCT have consistently permitted the recovery of tax effects previously flowed-through earnings, the Company has established regulatory liabilities and assets offsetting such deferred tax assets and liabilities. The Company recognizes only the impact of tax positions that, based on their merits, are more likely than not to be sustained upon an IRS audit. The Company defers investment tax credits related to rate regulated assets and amortizes them over the estimated useful lives of those assets. See Note 11 for additional information, including a discussion of the impacts of tax reform under the Tax Cuts and Jobs Act enacted on December 22, 2017.

The Company makes an estimate of its anticipated effective tax rate for the year as of the end of each quarterly period within its fiscal year. In interim periods, income tax expense is calculated by applying the anticipated annual effective tax rate to year-to-date earnings before taxes, which includes the earnings attributable to the Valencia non-controlling interest. GAAP also provides that certain unusual or infrequently occurring items, as well as adjustments due to enactment of new tax laws, be excluded from the estimated annual effective tax rate calculation.

Excise Taxes

The Company pays certain fees or taxes which are either considered to be an excise tax or similar to an excise tax. Substantially all of these taxes are recorded on a net basis in the Consolidated Statements of Earnings.

New Accounting Pronouncements

Information concerning recently issued accounting pronouncements that have not been adopted by the Company is presented below. The Company does not expect difficulty in adopting these standards by their required effective dates.

Accounting Standards Update 2014-09 – Revenue from Contracts with Customers (Topic 606)

In May 2014, the FASB issued ASU 2014-09. The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 also revises the disclosure requirements regarding revenue. Since the issuance of ASU 2014-09, the FASB issued a one-year deferral of the effective date and has issued additional ASUs that clarify implementation guidance regarding principal versus agent considerations, licensing, and identifying performance obligations, as well as adding certain additional practical expedients. The new standard will replace most existing revenue recognition guidance in GAAP. ASU 2014-09 can be applied retrospectively to each prior period presented or on a modified retrospective basis with a cumulative effect adjustment to retained earnings on the date of adoption. The Company will adopt ASU 2014-09 effective as of January 1, 2018, its required effective date, using the modified retrospective method of adoption.

The Company has monitored the activities of the FASB and other non-authoritative groups regarding certain issues specific to the power and utility industry. These specific issues include the impacts of the new guidance on accounting for CIAC and the presentation of revenues associated with "alternative revenue programs," which primarily result from certain of the Company's approved rate rider programs. The appropriate authoritative accounting organization has given tentative approval of the utility industry's positions on all power and utility specific issues. The Company has substantially completed its assessment of ASU 2014-09 and does not anticipate a cumulative effect adjustment on the date of adoption or changes to the amount and timing of its current revenue recognition practices. The Company believes its existing policies, processes, information technology infrastructure, and internal controls properly capture and report revenue in accordance with ASU 2014-09.

Accounting Standards Update 2016-01 – Financial Instruments (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU 2016-01, which makes targeted improvements to GAAP regarding financial instruments. ASU 2016-01 eliminates the requirement to classify investments in equity securities with readily determinable fair values into trading or available-for-sale categories and requires those equity securities to be measured at fair value with changes in fair value recognized in net earnings rather than in OCI. Unrealized gains, net of income taxes, recorded in AOCI related to equity securities will be reclassified to retained earnings as a cumulative effect adjustment. ASU 2016-01 also revises certain presentation and disclosure requirements. Under ASU 2016-01, accounting for investments in debt securities remains essentially unchanged.

PNM currently classifies all investments held in the NDT and coal mine reclamation trusts as available-for-sale securities. Unrealized losses on these securities are recorded immediately through earnings and unrealized gains are recorded in AOCI until the securities are sold. The Company will adopt ASU 2016-01 effective as of January 1, 2018, its required effective date. On January 1, 2018, PNMR and PNM will record a cumulative effect adjustment, net of income taxes, to increase retained earnings by $11.1 million with an offset to AOCI. Future changes in the fair value of equity securities will be recorded in earnings.

Accounting Standards Update 2016-02 – Leases (Topic 842)

In February 2016, the FASB issued ASU 2016-02 to provide guidance on the recognition, measurement, presentation, and disclosure of leases. ASU 2016-02 will require that a liability be recorded on the balance sheet for all leases, based on the present value of future lease obligations. A corresponding right-of-use asset will also be recorded. Amortization of the lease obligation and the right-of-use asset for certain leases, primarily those classified as operating leases, will be on a straight-line basis, which is not expected to have a significant impact on the statements of earnings, whereas other leases will be required to be accounted for as financing arrangements similar to the accounting treatment for capital leases under current GAAP. ASU 2016-02 also revises certain disclosure requirements. At adoption, ASU 2016-02 requires that leases be recognized and measured as of the earliest period presented using a modified retrospective approach with all periods presented being restated and presented under the new guidance. The ASU allows entities to apply certain practical expedients to arrangements that exist upon adoption or expired during the periods presented.

As further discussed in Note 7, the Company has operating leases of office buildings, vehicles, and equipment. The Company also routinely enters into land easements and right-of-way agreements. PNM also has operating lease interests in PVNGS Units 1 and 2 that will expire in January 2023 and 2024.

The Company, along with others in the utility industry, is continuing to monitor the activities of the FASB and other non-authoritative groups regarding industry specific issues for further clarification. The Company has formed a project team, conducted outreach activities across its lines of business, and made significant progress in identifying arrangements, in addition to its existing operating lease arrangements, that may be classified as leases under ASU 2016-02. It is likely the arrangements currently classified as leases will continue to be recognized as leases under ASU 2016-02. It is possible that other contractual arrangements not previously meeting the lease definition may contain elements that qualify as leases and that previously identified operating leases may be classified as financing leases under ASU 2016-02. The Company is in the process of analyzing each of the identified contractual arrangement to determine if it contains lease elements under the new standard and quantifying the potential impacts of identified lease arrangements. The Company is also evaluating the practical expedients, if any, it will elect upon adoption. The Company anticipates this process will continue into 2018. The Company will adopt this standard effective as of January 1, 2019, its required effective date.

In January 2018, the FASB issued ASU 2018-01, which clarifies that land easements are to be evaluated under ASU 2016-02, but provides an additional optional practical expedient to not evaluate existing or expired land easements that were not accounted for as leases under the current guidance. The Company has numerous land easements and right-of-way agreements that would fall under this clarification. The only such agreement that has been accounted for as a lease under current guidance is the right-of-way agreement with the Navajo Nation (Note 7). The Company anticipates it will elect to use the practical expedient for its existing and expired land easements upon adoption of ASU 2016-02.

Accounting Standards Update 2016-13 – Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments

In June 2016, the FASB issued ASU 2016-13, which changes the way entities recognize impairment of many financial assets, including accounts receivable and investments in debt securities, by requiring immediate recognition of estimated credit losses expected to occur over the remaining lives of the assets. The Company anticipates adopting ASU 2016-13 effective as of January 1, 2020 although early adoption is permitted beginning on January 1, 2019. The Company is in the process of analyzing the impacts of this new standard, but does not anticipate it will have a significant impact on its financial statements.

Accounting Standards Update 2016-18 – Statement of Cash Flows (Topic 230): Restricted Cash

In November 2016, the FASB issued ASU 2016-18, which requires that amounts generally described as restricted cash and restricted cash equivalents be included with cash and cash equivalents when reconciling the beginning of period and end of period amounts shown on the statements of cash flows and adds disclosures necessary to reconcile such amounts to cash and cash equivalents on the balance sheets. ASU 2016-18 does not provide a definition of what should be considered restricted cash. Upon adoption, ASU 2016-18 requires the use of a retrospective transition method for each period presented. The Company has substantially completed its analysis of ASU 2016-18 and will adopt the standard effective as of January 1, 2018, its required effective date. During 2015, PNM received a deposit of $8.2 million from a third party that was restricted for PNM's construction of transmission interconnection facilities for that party. PNM recorded the deposit in Other deferred charges and it was not included in cash on the Consolidated Statements of Cash Flows. Construction of the interconnection was completed in 2018, at which time $7.1 million was refunded to the third party. Other amounts considered to be restricted cash under ASU 2016-18 were insignificant. In 2018, PNM will reclassify amounts related to restricted cash on the Consolidated Statements of Cash Flows in accordance with ASU 2016-18 and provide the required additional disclosures.

Accounting Standards Update 2017-04 – Intangibles – Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment

In January 2017, the FASB issued ASU 2017-04 to simplify the annual goodwill impairment assessment process. Currently, the first step of a quantitative impairment test requires an entity to compare the fair value of each reporting unit containing goodwill with its carrying value (including goodwill). If as a result of this analysis, the entity concludes there is an indication of impairment in a reporting unit having goodwill, the entity is required to perform the second step of the impairment analysis, determining the amount of goodwill impairment to be recorded. The amount is calculated by comparing the implied fair value of the goodwill to its carrying amount. This exercise requires the entity to allocate the fair value determined in step one to the individual assets and liabilities of the reporting unit. Any remaining fair value would be the implied fair value of goodwill on the testing date. To the extent the recorded amount of goodwill of a reporting unit exceeds the implied fair value determined in step two, an impairment loss would be reflected in results of operations. ASU 2017-04 eliminates the second step of the impairment analysis. Accordingly,

if the first step of a quantitative goodwill impairment analysis performed after adoption of ASU 2017-04 indicates that the fair value of a reporting unit is less than its carrying value, the goodwill of that reporting unit would be impaired to the extent of that difference. The Company anticipates it will adopt ASU 2017-04 for impairment testing after January 1, 2020, its required effective date, although early adoption is permitted. However, if there is an indication of potential impairment of goodwill as a result of an impairment assessment prior to 2020, the Company will evaluate the impact of ASU 2017-04 and could elect to early adopt this standard.

Accounting Standards Update 2017-07 – Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU 2017-07 to improve the presentation of net periodic pension and other postretirement benefit costs. Currently, the Company presents all of its net periodic benefit costs, net of amounts capitalized to construction and other accounts, as administrative and general expenses on its statements of earnings. The amendments in ASU 2017-07 require the service cost component of net benefit costs be presented in the same line item or items as employees' compensation. The other components of net benefit cost (the "non-service cost components") are required to be presented in the income statement separately from the service cost component and outside of operating income with disclosures identifying where the non-service cost components have been presented. ASU 2017-07 also limits capitalization to only the service cost component of benefit costs. PNMR and its subsidiaries maintain qualified defined benefit pension and OPEB plans. Currently, net periodic benefit cost for the Company's defined benefit pension plans do not include a service cost component and there is only a minor amount of service cost for the OPEB plans. Additional information about the Company's benefit plans is discussed in Note 12. ASU 2017-07 requires retrospective presentation of the service and non-service cost components of net benefit costs in the income statement and prospective application regarding the capitalization of only the service cost component of net benefit costs. The Company will adopt the standard effective as of January 1, 2018, its required effective date. In 2017 and 2016, PNM recorded pre-tax Administrative and general expenses of $4.7 million and $3.0 million and TNMP recorded less than $0.1 million and less than $0.1 million related to their non-service cost components of net periodic benefit costs. Beginning in 2018, such costs will be reclassified to Other (deductions) on the Consolidated Statements of Earnings. The Company believes PNM and TNMP can continue to capitalize the non-service cost components of net benefit costs as regulatory assets to the extent attributable to regulated operations and does not anticipate ASU 2017-07 will have a significant impact on its financial statements.

Accounting Standards Update 2017-12 – Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities

In August 2017, the FASB issued ASU 2017-12 to better align hedge accounting with an organization's risk management activities and to simplify the application of hedge accounting guidance. ASU 2017-12 is effective for the Company on January 1, 2019 although early adoption is permitted beginning on January 1, 2018. As discussed in Note 6, the Company periodically enters into, and designates as cash flow hedges, interest rate swaps to hedge its exposure to changes in interest rates. In addition, as discussed in Note 8, the Company enters into various derivative instruments to economically hedge the risk of changes in commodity prices, which are not currently designated as cash flow hedges. The Company is evaluating the requirements of ASU 2017-12, but does not anticipate the changes will have a significant impact on the Company's accounting treatment for derivative instruments or on its financial statements.

(2) Segment Information

The following segment presentation is based on the methodology that management uses for making operating decisions and assessing performance of its various business activities. A reconciliation of the segment presentation to the GAAP financial statements is provided.

PNM

PNM includes the retail electric utility operations of PNM that are subject to traditional rate regulation by the NMPRC. PNM provides integrated electricity services that include the generation, transmission, and distribution of electricity for retail electric customers in New Mexico. PNM also includes the generation and sale of electricity into the wholesale market, as well as providing transmission services to third parties. The sale of electricity includes the asset optimization of PNM's jurisdictional assets as well as the capacity excluded from retail rates. FERC has jurisdiction over wholesale and transmission rates.

TNMP

TNMP is an electric utility providing services in Texas under the TECA. TNMP's operations are subject to traditional rate regulation by the PUCT. TNMP provides transmission and distribution services at regulated rates to various REPs that, in turn, provide retail electric service to consumers within TNMP's service area.

Corporate and Other

The Corporate and Other segment includes PNMR holding company activities, primarily related to corporate level debt and PNMR Services Company. The activities of PNMR Development and NM Capital are also included in Corporate and Other.

PNMR SEGMENT INFORMATION

The following tables present summarized financial information for PNMR by segment. PNM and TNMP each operate in only one segment. Therefore, tabular segment information is not presented for PNM and TNMP.

2017	PNM	TNMP	Corporate and Other	PNMR Consolidated
			(In thousands)	

Electric operating revenues	$ 1,104,230	$ 340,773	$ —	$ 1,445,003
Cost of energy	321,677	85,802	—	407,479
Utility margin	782,553	254,971	—	1,037,524
Other operating expenses	423,011	98,221	(22,135)	499,097
Depreciation and amortization	147,017	63,146	21,779	231,942
Operating income	212,525	93,604	356	306,485
Interest income	8,454	—	7,462	15,916
Other income (deductions)	30,686	3,551	(3,254)	30,983
Interest charges	(82,697)	(30,084)	(14,844)	(127,625)
Segment earnings (loss) before income taxes	168,968	67,071	(10,280)	225,759
Income taxes	81,555	31,512	17,273	130,340
Segment earnings (loss)	87,413	35,559	(27,553)	95,419
Valencia non-controlling interest	(15,017)	—	—	(15,017)
Subsidiary preferred stock dividends	(528)	—	—	(528)
Segment earnings (loss) attributable to PNMR	$ 71,868	$ 35,559	$ (27,553)	$ 79,874
At December 31, 2017:				
Total Assets	$ 4,921,563	$ 1,500,770	$ 223,770	$ 6,646,103
Goodwill	$ 51,632	$ 226,665	$ —	$ 278,297

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2017, 2016 and 2015

S&P Global Market Intelligence

2016	PNM	TNMP	Corporate and Other	PNMR Consolidated
Electric operating revenues	$ 1,035,913	$ 327,038	$ —	$ 1,362,951
Cost of energy	299,714	80,882	—	380,596
Utility margin	736,199	246,156	—	982,355
Other operating expenses	414,662	93,389	(12,791)	495,260
Depreciation and amortization	133,447	61,126	14,537	209,110
Operating income (loss)	188,090	91,641	(1,746)	277,985
Interest income	10,173	—	12,120	22,293
Other income (deductions)	22,066	3,202	(1,739)	23,529
Interest charges	(87,469)	(29,335)	(11,829)	(128,633)
Segment earnings (loss) before income taxes	132,860	65,508	(3,194)	195,174
Income taxes (benefit)	40,922	23,836	(1,480)	63,278
Segment earnings (loss)	91,938	41,672	(1,714)	131,896
Valencia non-controlling interest	(14,519)	—	—	(14,519)
Subsidiary preferred stock dividends	(528)	—	—	(528)
Segment earnings (loss) attributable to PNMR	$ 76,891	$ 41,672	$ (1,714)	$ 116,849
At December 31, 2016:				
Total Assets	$ 4,867,546	$ 1,383,223	$ 220,311	$ 6,471,080
Goodwill	$ 51,632	$ 226,665	$ —	$ 278,297

2015	PNM	TNMP	Corporate and Other	PNMR Consolidated
Electric operating revenues	$ 1,131,195	$ 307,887	$ —	$ 1,439,082
Cost of energy	391,131	73,518	—	464,649
Utility margin	740,064	234,369	—	974,433
Other operating expenses	590,967	88,051	(14,854)	664,164
Depreciation and amortization	115,717	56,285	13,917	185,919
Operating income	33,380	90,033	937	124,350
Interest income	6,574	—	(76)	6,498
Other income (deductions)	26,914	3,736	(485)	30,165
Interest charges	(79,950)	(27,681)	(7,229)	(114,860)
Segment earnings (loss) before income taxes	(13,082)	66,088	(6,853)	46,153
Income taxes (benefit)	(12,758)	24,125	3,708	15,075
Segment earnings (loss)	(324)	41,963	(10,561)	31,078
Valencia non-controlling interest	(14,910)	—	—	(14,910)

Subsidiary preferred stock dividends	(528)	—	—	(528)
Segment earnings (loss) attributable to PNMR	$ (15,762)	$ 41,963	$ (10,561)	$ 15,640
At December 31, 2015:				
Total Assets	$ 4,599,344	$ 1,297,139	$ 112,845	$ 6,009,328
Goodwill	$ 51,632	$ 226,665	$ —	$ 278,297

The Company defines utility margin as electric operating revenues less cost of energy. Cost of energy consists primarily of fuel and purchase power costs for PNM and costs charged by third-party transmission providers for TNMP. The Company believes that utility margin provides a more meaningful basis for evaluating operations than electric operating revenues since substantially all such costs are offset in revenues as fuel and purchase power costs are passed through to customers under PNM's FPPAC and third-party transmission costs are passed on to customers through TNMP's transmission cost recovery factor. Utility margin is not a financial measure required to be presented under GAAP and is considered a non-GAAP measure.

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Major Customers

No individual customer accounted for more than 10% of the electric operating revenues of PNMR or PNM. Three REPs accounted for more than 10% of the electric operating revenues of TNMP, as follows:

	Year Ended December 31,		
	2017	**2016**	**2015**
REP A	16 %	16 %	16 %
REP B	11 %	11 %	13 %
REP C	10 %	11 %	11 %

(3) Related Party Transactions

PNMR, PNM, and TNMP are considered related parties as defined under GAAP, as is PNMR Services Company, a wholly-owned subsidiary of PNMR that provides corporate services to PNMR and its subsidiaries in accordance with shared services agreements. These services are billed at cost on a monthly basis to the business units.

PNMR files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PNMR and each of its affiliated companies. These agreements provide that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PNMR. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PNMR to the extent that PNMR is able to utilize those benefits.

See Note 6 for information on intercompany borrowing arrangements. The table below summarizes the nature and amount of related party transactions of PNMR, PNM and TNMP:

	Year Ended December 31,		
	2017	**2016**	**2015**
	(In thousands)		
Services billings:			
PNMR to PNM	$ 97,914	$ 94,606	$ 90,827
PNMR to TNMP	31,095	28,907	28,109
PNM to TNMP	382	427	554
TNMP to PNMR	141	66	41
TNMP to PNM	154	172	—
Interest billings:			
PNMR to PNM	21	11	54
PNM to PNMR	220	150	110
PNMR to TNMP	133	132	276
Income tax sharing payments:			
PNMR to TNMP	—	—	—
PNMR to PNM	23,391	—	1,450
TNMP to PNMR	20,686	—	—

(4) Regulatory Assets and Liabilities

The operations of PNM and TNMP are regulated by the NMPRC, PUCT, and FERC and the provisions of GAAP for rate-regulated enterprises are applied to its regulated operations. Regulatory assets represent probable future recovery of previously incurred costs that will be collected from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process. Regulatory assets and liabilities reflected in the Consolidated Balance Sheets are presented below.

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	PNM		TNMP	
	December 31,		December 31,	
	2017	2016	2017	2016
Assets:	(In thousands)			
Current:				
FPPAC	$ 363	$ 1,451	$ —	$ —
Energy efficiency costs	1,776	1,991	794	413
	2,139	3,442	794	413
Non-Current:				
CTC, including carrying charges	—	—	26,998	36,328
Coal mine reclamation costs	16,462	22,383	—	—
Deferred income taxes	59,220	62,918	9,621	9,932
Loss on reacquired debt	22,744	24,404	32,808	34,107
Pension and OPEB	222,774	249,286	26,153	27,661
Shutdown of SJGS Units 2 and 3	125,539	—	—	—
Hurricane recovery costs	—	—	6,640	—
AMS surcharge	—	—	27,903	14,669
AMS retirement costs	—	—	8,948	11,086
Other	12,500	6,422	2,362	2,027
	459,239	365,413	141,433	135,810
Total regulatory assets	$ 461,378	$ 368,855	$ 142,227	$ 136,223

	PNM		TNMP	
	December 31,		December 31,	
	2017	2016	2017	2016
Liabilities:	(In thousands)			
Current:				
Renewable energy rider	$ (779)	$ (3,411)	$ —	$ —
Other	(5)	(106)	(1,525)	(92)
	(784)	(3,517)	(1,525)	(92)
Non-Current:				
Cost of removal	(256,493)	(297,087)	(26,541)	(26,900)
Deferred income taxes	(445,390)	(62,920)	(148,455)	(2,644)
PVNGS ARO	(24,889)	(30,621)	—	—
Renewable energy tax benefits	(21,383)	(22,540)	—	—
Nuclear spent fuel reimbursements	(5,518)	(8,875)	—	—
Pension and OPEB	—	—	(3,442)	(1,955)
Other	(768)	(1,658)	(699)	(449)
	(754,441)	(423,701)	(179,137)	(31,948)
Total regulatory liabilities	$ (755,225)	$ (427,218)	$ (180,662)	$ (32,040)

The Company's regulatory assets and regulatory liabilities are reflected in rates charged to customers or have been addressed in a regulatory proceeding. The Company does not receive or pay a rate of return on the following regulatory assets and regulatory liabilities (and their remaining amortization periods): coal mine reclamation costs (through 2020); deferred income taxes (over the remaining life of the taxable item, up to the remaining life of utility plant); pension and OPEB costs (through 2033); and PVNGS ARO (to be determined in a future regulatory proceeding). In addition, TNMP does not currently receive a return on its loss on reacquired debt (through 2043).

The Company is permitted, under rate regulation, to accrue and record a regulatory liability for the estimated cost of removal and salvage associated with certain of its assets through depreciation expense. Under GAAP, actuarial losses and prior service costs for pension plans are required to be recorded in AOCI; however, to the extent authorized for recovery through the

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regulatory process these amounts are recorded as regulatory assets or liabilities. Based on prior regulatory approvals, the amortization of these amounts will be included in the Company's rates.

Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, the Company believes that future recovery of its regulatory assets is probable.

(5) Stockholders' Equity

Common Stock and Equity Contributions

PNMR, PNM, and TNMP did not issue any common stock during the three year period ended December 31, 2017. PNMR funded cash equity contributions of $28.1 million in 2016 and $175.0 million in 2015 to PNM and $50.0 million in 2017 and $50.0 million in 2016 to TNMP. PNMR offers shares of PNMR common stock through the PNMR Direct Plan. PNMR utilizes shares of its common stock purchased on the open market, by an independent agent, rather than issuing additional shares to satisfy subscriptions under the PNMR Direct Plan. The shares of PNMR common stock utilized in the PNMR Direct Plan are offered under a SEC shelf registration statement that expires in August 2018.

Dividends on Common Stock

The declaration of common dividends by PNMR is dependent upon a number of factors, including the ability of PNMR's subsidiaries to pay dividends. PNMR's primary sources of dividends are its operating subsidiaries.

PNM declared and paid cash dividends to PNMR of $60.7 million, $4.1 million, and $94.4 million in 2017, 2016, and 2015. TNMP paid cash dividends to PNMR of $44.4 million, $31.8 million, and $33.2 million in 2017, 2016, and 2015.

The NMPRC has placed certain restrictions on the ability of PNM to pay dividends to PNMR, including the restriction that PNM cannot pay dividends that cause its debt rating to fall below investment grade. The NMPRC provisions allow PNM to pay dividends, without prior NMPRC approval, from current earnings, which is determined on a rolling four quarter basis, or from equity contributions previously made by PNMR. The Federal Power Act also imposes certain restrictions on dividends by public utilities, including that dividends cannot be paid from paid-in capital. The Company's revolving credit facilities and term loans contain a covenant requiring the maintenance of debt-to-capital ratios of not more than 65%, which could limit amounts of dividends that could be paid. PNM also has other financial covenants that limit the transfer of assets, through dividends or other means, including a requirement to obtain approval of certain financial counterparties to transfer more than five percent of PNM's assets. As of December 31, 2017: none of the numerical tests would restrict the payment of dividends from the retained earnings of TNMP; the transfer of assets limitation would allow the payment of dividends by PNM of up to $246.1 million; and the 65% debt-to-capital covenant would allow the payment of dividends by PNMR of up to $133.9 million.

In addition, the ability of PNMR to declare dividends is dependent upon the extent to which cash flows will support dividends, the availability of retained earnings, financial circumstances and performance, current and future regulatory decisions, Congressional and legislative acts, and economic conditions. Conditions imposed by the NMPRC or PUCT, future growth plans and related capital requirements, and business considerations may also affect PNMR's ability to pay dividends.

Preferred Stock

PNM's cumulative preferred shares outstanding bear dividends at 4.58% per annum. PNM preferred stock does not have a mandatory redemption requirement, but may be redeemed, at PNM's option, at 102% of the stated value plus accrued dividends. The holders of the PNM preferred stock are entitled to payment before the holders of common stock in the event of any liquidation or dissolution or distribution of assets of PNM. In addition, PNM's preferred stock is not entitled to a sinking fund and cannot be converted into any other class of stock of PNM.

PNMR and TNMP have no preferred stock outstanding. The authorized shares of PNMR and TNMP preferred stock are 10 million shares and 1 million shares.

(6) Financing

The Company's financing strategy includes both short-term and long-term borrowings. The Company utilizes short-term revolving credit facilities, as well as cash flows from operations, to provide funds for both construction and operating expenditures.

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Depending on market and other conditions, the Company will periodically sell long-term debt or enter into term loan arrangements and use the proceeds to reduce borrowings under the revolving credit facilities or refinance other debt. Each of the Company's revolving credit facilities and term loans contains a single financial covenant, which requires the maintenance of a debt-to-capital ratio of less than or equal to 65%, and generally also include customary covenants, events of default, cross default provisions and change of control provisions.

PNM must obtain NMPRC approval for any financing transaction having a maturity of more than 18 months. In addition, PNM files its annual short-term financing plan with the NMPRC.

Financing Activities

PNMR

At January 1, 2015, PNMR had outstanding the one-year $100.0 million PNMR Term Loan Agreement, which was due in December 2015. In December 2015, PNMR entered into an agreement that extended the maturity date for an additional year and increased the amount outstanding to $150.0 million. The PNMR Term Loan Agreement was repaid on December 21, 2016.

On March 9, 2015, PNMR entered into a $150.0 million Term Loan Agreement (the "PNMR 2015 Term Loan Agreement") between PNMR, the lenders identified therein, and Wells Fargo Bank, National Association, as lender and administrative agent. The PNMR 2015 Term Loan Agreement bears interest at a variable rate, which was 2.34% at December 31, 2017, and must be repaid on or before March 9, 2018.

At January 1, 2015, PNMR had an aggregate outstanding principal amount of $118.8 million of its 9.25% Senior Unsecured Notes, Series A, which were due on May 15, 2015. PNMR repaid all of the 9.25% Senior Unsecured Notes at the scheduled maturity, utilizing proceeds from the PNMR 2015 Term Loan Agreement and borrowings under the PNMR Revolving Credit Facility.

As discussed in Note 16, NM Capital, a wholly-owned subsidiary of PNMR, entered into a $125.0 million term loan agreement (the "BTMU Term Loan Agreement") with BTMU, as lender and administrative agent, as of February 1, 2016. The BTMU Term Loan Agreement has a maturity of February 1, 2021 and bears interest at a rate based on LIBOR plus a

customary spread, which aggregated 4.13% at December 31, 2017. PNMR, as parent company of NM Capital, has guaranteed NM Capital's obligations to BTMU. NM Capital utilized the proceeds of the BTMU Term Loan Agreement to provide funding of $125.0 million (the "Westmoreland Loan") to a ring-fenced, bankruptcy-remote, special-purpose entity that is a subsidiary of Westmoreland Coal Company to finance Westmoreland's purchase of SJCC. The BTMU Term Loan Agreement requires that NM Capital utilize all amounts, less taxes and fees, it receives under the Westmoreland Loan to repay the BTMU Term Loan Agreement. The principal balance outstanding under the BTMU Term Loan Agreement was $50.1 million at December 31, 2017 and $45.1 million at February 20, 2018. Based on scheduled payments on the Westmoreland Loan and WSJ's payment of $5.6 million on February 1, 2018, (which included $4.8 million in excess of the scheduled payment), NM Capital estimates it will make principal payments of $10.6 million on the BTMU Term Loan Agreement in the year ended December 31, 2018, including the payment made on February 1, 2018 of $5.0 million (which included $3.3 million in excess of the payment previously scheduled).

On October 21, 2016, PNMR entered into letter of credit arrangements with JPMorgan Chase Bank, N.A. (the "JPM LOC Facility") under which letters of credit aggregating $30.3 million were issued to facilitate the posting of reclamation bonds, which SJCC is required to post in connection with permits relating to the operation of the San Juan mine (Note 16).

On December 21, 2016, PNMR entered into two term loan agreements: (1) a $100.0 million term loan agreement (the "PNMR 2016 One-Year Term Loan") among PNMR, the lenders identified therein, and Wells Fargo Bank, National Association, as administrative agent, that was to mature on December 21, 2017; and (2) a $100.0 million term loan agreement (the "PNMR 2016 Two-Year Term Loan") among PNMR and JPMorgan Chase Bank, N.A., as lender and administrative agent, that matures on December 21, 2018. The proceeds of the term loans were used to repay the $150.0 million PNMR Term Loan Agreement and to reduce borrowings under the PNMR Revolving Credit Facility. On December 15, 2017, the PNMR 2016 One-Year Term Loan was extended to December 14, 2018. The PNMR 2016 One-Year Term Loan (as extended) and the PNMR 2016 Two-Year Term Loan bear interest at variable rates, which were 2.32% and 2.32% at December 31, 2017.

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PNM

On January 1, 2015, PNM had a $125.0 million multi-draw term loan facility (the "PNM Multi-draw Term Loan") that had outstanding borrowings of $100.0 million and a maturity date of June 21, 2016. PNM drew the remaining capacity of $25.0 million on May 8, 2015. The PNM Multi-draw Term Loan was repaid on May 20, 2016.

At January 1, 2015, PNM had a $39.3 million series of outstanding Senior Unsecured Notes, Pollution Control Revenue Bonds, which have a final maturity of June 1, 2043. These PCRBs were subject to mandatory tender for remarketing on June 1, 2015 and were successfully remarketed on that date. The notes now bear interest at 2.45%, continue to have an outstanding amount of $39.3 million, and are subject to mandatory tender for remarketing on June 1, 2020.

On August 11, 2015, PNM issued $250.0 million aggregate principal amount of its 3.850% Senior Unsecured Notes due 2025. The notes will mature on August 1, 2025. Portions of the proceeds from the offering were used to repay an existing $175.0 million term loan and to repay outstanding borrowings under the PNM Revolving Credit Facility, the PNM 2014 New Mexico Credit Facility, and PNM's intercompany loan from PNMR.

On May 20, 2016, PNM entered into a $175.0 million term loan agreement (the "PNM 2016 Term Loan Agreement") between PNM and JPMorgan Chase Bank, N.A., as lender and administrative agent. The PNM 2016 Term Loan Agreement bore interest at a variable rate and had a maturity date of November 17, 2017. PNM used a portion of the proceeds of the PNM 2016 Term Loan Agreement to prepay without penalty the $125.0 million outstanding under the PNM Multi-draw Term Loan. The PNM 2016 Term Loan Agreement was repaid on July 20, 2017.

On September 27, 2016, PNM participated in the issuance and sale of an aggregate of $146.0 million of PCRBs by the City of Farmington, New Mexico. The proceeds from the sale were utilized to refund an aggregate of $146.0 million of outstanding PCRBs previously issued by the City of Farmington. The arrangements governing the PCRBs result in PNM reflecting the bonds as debt on its financial statements. The PCRBs bear interest at a rate of 1.875% for the period from September 27, 2016 through September 30, 2021, have a mandatory tender for remarketing on October 1, 2021, and a final maturity on April 1, 2033.

At January 1, 2015, PNM had $37.0 million of outstanding PCRBs, which have a final maturity of June 1, 2040, and $20.0 million of outstanding PCRBs which have a final maturity of June 1, 2042. These PCRBs were subject to mandatory tender for remarketing on June 1, 2017 and were successfully remarketed on that date. The $37.0 million of PCRBs now bear interest at 2.125% and the $20.0 million of PCRBs now bear interest at 2.45%. Both series are now subject to mandatory tender for remarketing on June 1, 2022.

On July 20, 2017, PNM entered into a $200.0 million term loan agreement (the "PNM 2017 Term Loan Agreement") between PNM and JPMorgan Chase Bank, N.A., as lender and administrative agent, and U.S. Bank National Association, as lender. The PNM 2017 Term Loan Agreement bears interest at a variable rate, which was 2.29% at December 31, 2017, and must be repaid on or before January 18, 2019. PNM used the proceeds of the PNM 2017 Term Loan Agreement to prepay without penalty the $175.0 million PNM 2016 Term Loan Agreement and to reduce short-term borrowings.

On July 28, 2017, PNM entered into an agreement (the "PNM 2017 Senior Unsecured Note Agreement") with institutional investors for the sale of $450.0 million aggregate principal amount of Senior Unsecured Notes (the "PNM 2018 SUNs") offered in private placement transactions. Under the PNM 2017 Senior Unsecured Note Agreement, PNM has agreed to issue $350.0 million of the PNM 2018 SUNs on or about May 15, 2018 and $100.0 million of the PNM 2018 SUNs on or about August 1, 2018. The issuances of the PNM 2018 SUNs are subject to the satisfaction of customary conditions. PNM will use the gross proceeds from the PNM 2018 SUNs to repay $350.0 million of PNM's 7.95% Senior Unsecured Notes that mature on May 15, 2018 and $100.0 million of PNM's 7.50% Senior Unsecured Notes that mature on August 1, 2018. The terms of the PNM 2017 Senior Unsecured Note Agreement include customary covenants, including a covenant that requires the maintenance of a debt-to-capital ratio of less than or equal to 65%, customary events of default, including a cross default provision, and covenants regarding parity of financial covenants, liens and guarantees with respect to PNM's material credit facilities. In the event of a change of control, PNM will be required to offer to prepay the PNM 2018 SUNs at par. PNM will have the right to redeem any or all of the PNM 2018 SUNs prior to their respective maturities, subject to payment of a customary make-whole premium. In accordance with GAAP, aggregate borrowings of $450.0 million under PNM's Senior Unsecured Notes due on May 15, 2018 and August 1, 2018, are reflected as being long-term in the Consolidated Balance Sheet at December 31, 2017 since the PNM 2017 Senior Unsecured Note Agreement demonstrates PNM's ability and intent to re-finance the aggregate $450.0 million Senior Unsecured Notes on a

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long-term basis. Information concerning the maturities and interest rates on the PNM 2018 SUNs to be issued in May 2018 and August 2018 is as follows:

Scheduled Funding Date	Maturity Date	Principal Amount	Interest Rate
		(In millions)	
May 15, 2018	May 15, 2023	$ 55.0	3.15%
May 15, 2018	May 15, 2025	104.0	3.45%
May 15, 2018	May 15, 2028	88.0	3.68%
May 15, 2018	May 15, 2033	38.0	3.93%
May 15, 2018	May 15, 2038	45.0	4.22%
May 15, 2018	May 15, 2048	20.0	4.50%
		350.0	
August 1, 2018	August 1, 2028	15.0	3.78%
August 1, 2018	August 1, 2048	85.0	4.60%
		100.0	
		$ 450.0	

PNM has a shelf registration statement, which will expire in May 2020, with capacity for the issuance of up to $475.0 million of senior unsecured notes.

TNMP

On December 17, 2015, TNMP entered into an agreement (the "TNMP 2015 Bond Purchase Agreement"), which provided that TNMP would issue $60.0 million aggregate principal amount of 3.53% first mortgage bonds, due 2026 on or about February 10, 2016, subject to satisfaction of certain conditions. TNMP issued the bonds on February 10, 2016 and used the proceeds to reduce short-term debt and intercompany debt.

On June 14, 2017, TNMP entered into an agreement (the "TNMP 2017 Bond Purchase Agreement"), which provided TNMP would issue $60.0 million aggregate principal amount of 3.22% first mortgage bonds, due 2027 on or about August 25, 2017, subject to satisfaction of certain conditions. TNMP issued the bonds on August 24, 2017 and used the proceeds to reduce short-term and intercompany debt and for general corporate purposes.

Interest Rate Hedging Activities

In September 2015, PNMR entered into a hedging agreement whereby it effectively established a fixed interest rate of 1.927%, subject to change if there is a change in PNMR's credit rating, for borrowings under the PNMR 2015 Term Loan Agreement for the period from January 11, 2016 through its maturity on March 9, 2018. In 2017, PNMR entered into three separate four-year hedging agreements whereby it effectively established fixed interest rates of 1.926%, 1.823%, and 1.629%, plus customary spreads over LIBOR, subject to change if there is a change in PNMR's credit rating, for three separate tranches, each of $50.0 million, of its variable rate debt.

These hedge agreements are accounted for as cash flow hedges. The fair value of the hedge related to the PNMR 2015 Term Loan Agreement was a gain of $0.2 million at December 31, 2017 and is included in Other current assets on the Consolidated Balance Sheets and a loss of less than $0.1 million at December 31, 2016. At December 31, 2017, the remaining hedge agreements had fair value gains totaling $1.4 million, which are included in Other current assets on the Consolidated Balance Sheets. The fair values were determined using Level 2 inputs under GAAP, including using forward LIBOR curves under the mid-market convention to discount cash flows over the remaining term of the agreement.

Borrowing Arrangements Between PNMR and its Subsidiaries

PNMR has one-year intercompany loan agreements with its subsidiaries. Individual subsidiary loan agreements vary in amount up to $100.0 million and have either reciprocal or non-reciprocal terms. Interest charged to the subsidiaries is equivalent to interest paid by PNMR on its short-term borrowings or the money-market interest rate if PNMR does not have any short-term borrowings outstanding. TNMP had no outstanding borrowings from PNMR at December 31, 2017 or February 20, 2018, and

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$4.6 million at December 31, 2016. PNM had no outstanding borrowings from PNMR at December 31, 2017, December 31, 2016, or February 20, 2018.

Short-term Debt

Currently, the PNMR Revolving Credit Facility has a financing capacity of $300.0 million and the PNM Revolving Credit Facility has a financing capacity of $400.0 million. PNMR and PNM have entered into agreements to extend the maturity of both facilities from October 31, 2020 to October 31, 2022. However, one lender, whose current commitment is $10.0 million under the PNMR Revolving Credit Facility and $40.0 million under the PNM Revolving Credit Facility, did not agree to extend its commitments beyond October 31, 2020. Unless one or more of the other current lenders or a new lender assumes the commitments of the non-extending lender, the financing capacities will be reduced to $290.0 million for the PNMR Revolving Credit Facility and $360.0 million for the PNM Revolving Credit Facility from November 1, 2020 through October 31, 2022. The TNMP Revolving Credit Facility is a $75.0 million revolving credit facility secured by $75.0 million aggregate principal amount of TNMP first mortgage bonds. In September 2017, the TNMP Revolving Credit Facility was extended to mature on September 23, 2022.

At January 1, 2015, PNM had a $50.0 million unsecured revolving credit facility (the "PNM 2014 New Mexico Credit Facility") that was scheduled to expire on January 8, 2018. On December 12, 2017, PNM entered into a new $40.0 million unsecured revolving credit facility (the "PNM 2017 New Mexico Credit Facility") by and among PNM, the lenders identified therein, U.S. Bank National Association, as Administrative Agent, and BOKF, NA dba Bank of Albuquerque, as Syndication Agent to replace the PNM 2014 New Mexico Credit Facility. The eight participating lenders are all banks that have a significant presence or are headquartered in New Mexico. The PNM 2017 New Mexico Credit Facility expires on December 12, 2022 and contains covenants and conditions similar to those in the PNM Revolving Credit Facility.

Short-term debt outstanding consists of:

Short-term Debt	December 31, 2017	December 31, 2016
	(In thousands)	
PNM:		
PNM Revolving Credit Facility	$ 39,800	$ 35,000
PNM 2014 New Mexico Credit Facility	—	26,000
PNM 2017 New Mexico Credit Facility	—	—
	39,800	61,000
TNMP Revolving Credit Facility	—	—
PNMR:		
PNMR Revolving Credit Facility	165,600	126,100
PNMR 2016 One-Year Term Loan	100,000	100,000
	$ 305,400	$ 287,100

In addition to the above borrowings, PNMR, PNM, and TNMP had letters of credit outstanding of $6.4 million, $2.5 million, and $0.1 million at December 31, 2017 that reduce the available capacity under their respective revolving credit facilities. In addition, PNMR had $30.3 million of letters of credit outstanding under the JPM LOC Facility. At December 31, 2017, interest rates on outstanding borrowings were 2.76% for the PNMR Revolving Credit Facility and 2.59% for the PNM Revolving Credit Facility.

At February 20, 2018, PNMR, PNM, and TNMP had $111.2 million, $340.1 million, and $51.0 million of availability under their respective revolving credit facilities, including reductions of availability due to outstanding letters of credit, and PNM had $20.0 million availability under the PNM 2017 New Mexico Credit Facility. Total availability at February 20, 2018, on a consolidated basis, was $522.3 million for PNMR. At February 20, 2018, PNMR had invested cash of $0.9 million. PNM and TNMP had no invested cash at February 20, 2018.

On February 26, 2018, PNMR Development entered into a $24.5 million credit facility with Wells Fargo Bank, National Association, as lender. The facility allows PNMR Development to borrow on a revolving credit basis and also provides for the issuance of letters of credit. The facility matures on February 25, 2019. The facility bears interest at a variable rate and contains terms similar to the PNMR Revolving Credit Facility. PNMR has guaranteed the obligations of PNMR Development under the facility. PNMR Development anticipates using the facility to finance its participation in NMRD (Note 1).

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Long-Term Debt

Information concerning long-term debt outstanding and unamortized (premiums), discounts, and debt issuance costs is as follows:

	December 31, 2017		December 31, 2016	
	Principal	Unamortized Discounts, (Premiums), and Issuance Costs, net	Principal	Unamortized Discounts, (Premiums), and Issuance Costs, net
		(In thousands)		
PNM Debt				
Senior Unsecured Notes, Pollution Control Revenue Bonds:				
1.875% due April 2033, mandatory tender - October 1, 2021	$ 146,000	$ 1,383	$ 146,000	$ 1,807
6.25% due January 2038	36,000	228	36,000	239
4.75% due June 2040, mandatory tender - June 1, 2017	—	—	37,000	25
2.125% due June 2040, mandatory tender - June 1, 2022	37,000	404	—	—
5.20% due June 2040, mandatory tender - June 1, 2020	40,045	105	40,045	147
5.90% due June 2040	255,000	2,040	255,000	2,131
6.25% due June 2040	11,500	92	11,500	96
2.54% due September 2042, mandatory tender - June 1, 2017	—	—	20,000	67
2.45% due September 2042, mandatory tender - June 1, 2022	20,000	153	—	—
2.40% due June 2043, mandatory tender - June 1, 2020	39,300	243	39,300	340
5.20% due June 2043, mandatory tender - June 1, 2020	21,000	53	21,000	75
Senior Unsecured Notes:				
7.95% due May 2018	350,000	272	350,000	995
7.50% due August 2018	100,025	73	100,025	197
5.35% due October 2021	160,000	617	160,000	780
3.85% due August 2025	250,000	2,274	250,000	2,574
PNM 2016 Term Loan Agreement due November 2017	—	—	175,000	28
PNM 2017 Term Loan Agreement due January 2019	200,000	23	—	—
	1,665,870	7,960	1,640,870	9,501
Less current maturities	25	2	232,000	120
	1,665,845	7,958	1,408,870	9,381

TNMP Debt				
First Mortgage Bonds:				
9.50% due April 2019	172,302	1,032	172,302	1,857
6.95% due April 2043	93,198	(18,057)	93,198	(18,773)
4.03% due July 2024	80,000	686	80,000	792
3.53% due February 2026	60,000	667	60,000	749
3.22% due August 2027	60,000	552	—	—
	465,500	(15,120)	405,500	(15,375)
Less current maturities	—	—	—	—
	465,500	(15,120)	405,500	(15,375)
PNMR Debt				
PNMR 2015 Term Loan Agreement due March 2018	150,000	12	150,000	84
BTMU Term Loan Agreement, payments through February 2021	50,137	1,001	92,207	1,634
PNMR 2016 Two-Year Term Loan due December 2018	100,000	9	100,000	21
	300,137	1,022	342,207	1,739
Less current maturities	257,268	396	42,025	557
	42,869	626	300,182	1,182
Total Consolidated PNMR Debt	2,431,507	(6,138)	2,388,577	(4,135)
Less current maturities	257,293	398	274,025	677
	$ 2,174,214	$ (6,536)	$ 2,114,552	$ (4,812)

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Reflecting mandatory tender dates and the impacts of the refinancing under the PNM 2017 Senior Unsecured Note Agreement discussed above, long-term debt matures as follows:

	PNMR	PNM	TNMP	PNMR Consolidated
		(In thousands)		
2018	$ 257,268	$ 25	$ —	$ 257,293
2019	12,357	200,000	172,302	384,659
2020	25,862	100,345	—	126,207
2021	4,650	306,000	—	310,650
2022	—	57,000	—	57,000
Thereafter	—	1,002,500	293,198	1,295,698
Total	$ 300,137	$ 1,665,870	$ 465,500	$ 2,431,507

(7) Lease Commitments

The Company leases office buildings, vehicles, and other equipment under operating leases. In addition, PNM leases interests in Units 1 and 2 of PVNGS and, through April 1, 2015, leased an interest in the EIP transmission line. Many of PNM's electric transmission and distribution facilities are located on lands that require the grant of rights-of-way from governmental entities, Native American tribes, or private parties. PNM has completed several renewals of rights-of-way, the largest of which is a renewal with the Navajo Nation, and has no significant rights-of-way that will expire within the next five years. PNM is obligated to pay the Navajo Nation annual payments of $6.0 million, subject to adjustment each year based on the Consumer Price Index, through 2029. All of the Company's leases, as well as the Navajo Nation rights-of-way agreement, are accounted for as operating leases. See New Accounting Pronouncements in Note 1.

The PVNGS leases were entered into in 1985 and 1986 and initially were scheduled to expire on January 15, 2015 for the four Unit 1 leases and January 15, 2016 for the four Unit 2 leases. Each of the leases provided PNM with an option to purchase the leased assets at fair market value at the end of the leases, but PNM did not have a fixed price purchase option. In addition, the leases provided PNM with options to renew the leases at fixed rates set forth in each of the leases for two years beyond the termination of the original lease terms. The option periods on certain leases could be further extended for up to an additional six years (the "Maximum Option Period") if the appraised remaining useful lives and fair value of the leased assets were greater than parameters set forth in the leases. The rental payments during the fixed renewal option periods are 50% of the amounts during the original terms of the leases. Gross annual lease payments aggregated $33.0 million for the Unit 1 leases and $23.7 million for the Unit 2 leases prior to the expiration of their original terms.

Following procedures set forth in the PVNGS leases, PNM notified each of the four lessors under the Unit 1 leases and the lessor under the one Unit 2 lease containing the Maximum Option Period provision that it would elect to renew those leases for the Maximum Option Period on the expiration date of the original leases. PNM and each of those lessors entered into amendments to each of the leases setting forth the terms and conditions that would implement the extension of the term of the leases through the agreed upon Maximum Option Period. The four Unit 1 leases now expire on January 15, 2023 and the one Unit 2 lease now expires on January 15, 2024. The annual payments during the renewal periods aggregate $16.5 million for the PVNGS Unit 1 leases and $1.6 million for the Unit 2 lease, which are included in the table of future lease payments shown below.

For leases that were extended, the leases provide PNM with the option to purchase the leased assets at fair market value at the end of the extended lease terms. Each extended lease provides that no later than three years prior to the expiration of the lease, PNM is required to give notice to the lessor if it will "retain" the leased assets, through the purchase of the assets at the end of the lease, or "return" the leased assets to the lessor. The election made under each of the leases is irrevocable and independent of the elections made under the other leases. PNM has begun to analyze what action it will take with respect to each lease. If PNM elects to exercise its purchase option under any of the leases, PNM would attempt to negotiate the purchase price with the lessor of the lease. The leases provide an appraisal process to determine fair market value in the event the lessor and lessee cannot agree on a purchase price.

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For the three PVNGS Unit 2 leases that did not contain the Maximum Option Period provisions, PNM, following procedures set forth in the leases, notified each of the lessors that PNM would elect to purchase the assets underlying those leases on the expiration date of the original leases. PNM and the lessors under these leases entered into agreements that established the purchase price, representing the fair market value, to be paid by PNM for the assets underlying the leases on January 15, 2016. On January 15, 2016, PNM paid $78.1 million to the lessor under one lease for 31.25 MW of the entitlement from PVNGS Unit 2 and $85.2 million to the lessors under the other two leases for 32.76 MW of the entitlement from PVNGS Unit 2. See Note 17 for information concerning the NMPRC's treatment of the purchased assets and extended leases in PNM's NM 2015 Rate Case.

Covenants in PNM's PVNGS Units 1 and 2 lease agreements limit PNM's ability, without consent of the owner participants in the lease transactions, (i) to enter into any merger or consolidation, or (ii) except in connection with normal dividend policy, to convey, transfer, lease or dividend more than 5% of its assets in any single transaction or series of related transactions. PNM is exposed to losses under the PVNGS lease arrangements upon the occurrence of certain events that PNM does not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to PVNGS or the occurrence of specified nuclear events), PNM would be required to make specified payments to the owner participants, and take title to the leased interests. Exercise of renewal options under the leases required that amounts payable to the owner participants under the circumstances described above would increase to the fair market value as of the renewal date. If such an event had occurred as of December 31, 2017, amounts due to the lessors under the circumstances described above would be up to $169.9 million, payable on January 15, 2018 in addition to the scheduled lease payments due on January 15, 2018. In such event, PNM would record the acquired assets at the lower of their fair value or the amount paid.

PNM owned 60% of the EIP and leased the other 40%, under a lease that expired on April 1, 2015. The lease provided PNM the option of purchasing the leased assets at the end of the lease for fair market value, as well as options to renew the lease. On November 1, 2012, PNM and the lessor entered into a definitive agreement for PNM to exercise the option to purchase on April 1, 2015 the leased capacity at fair market value, which the parties agreed would be $7.7 million. PNM closed on the purchase on April 1, 2015 and recorded the purchase of the assets underlying the lease at that date.

Operating lease expense, including the PVNGS and EIP leases, was:

	PNMR	PNM	TNMP
		(In thousands)	
2017	$ 35,972	$ 31,817	$ 3,570
2016	$ 37,432	$ 32,843	$ 3,748
2015	$ 61,088	$ 55,994	$ 3,688

Future minimum operating lease payments at December 31, 2017 are shown below:

	PNMR	PNM	TNMP
		(In thousands)	
2018	$ 26,802	$ 25,726	$ 791
2019	25,638	25,241	296
2020	25,208	25,122	—
2021	25,122	25,122	—
2022	25,122	25,122	—
Later years	60,708	60,708	—
Total minimum lease payments	$ 188,600	$ 187,041	$ 1,087

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(8) Fair Value of Derivative and Other Financial Instruments

Fair value is defined under GAAP as the price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. Fair value is based on current market quotes as available and is supplemented by modeling techniques and assumptions made by the Company to the extent quoted market prices or volatilities are not available. External pricing input availability varies based on market liquidity, term of the agreement, and, for commodities, location. Valuations of derivative assets and liabilities take into account nonperformance risk, including the effect of counterparties' and the Company's credit risk. The Company regularly assesses the validity and availability of pricing data for its derivative transactions. Although the Company uses its best judgment in estimating the fair value of these instruments, there are inherent limitations in any estimation technique.

Energy Related Derivative Contracts

Overview

The primary objective for the use of commodity derivative instruments, including energy contracts, options, swaps, and futures, is to manage price risk associated with forecasted purchases of energy and fuel used to generate electricity, as well as managing anticipated generation capacity in excess of forecasted demand from existing customers. PNM's energy related derivative contracts manage commodity risk. PNM is required to meet the demand and energy needs of its customers. PNM is exposed to market risk for the needs of its customers

not covered under a FPPAC.

PNM was exposed to market risk for its share of PVNGS Unit 3 through December 31, 2017, at which time PVNGS Unit 3 became a jurisdictional resource to serve New Mexico retail customers. Beginning January 1, 2018, PNM is exposed to market risk for its 65 MW of SJGS Unit 4 that is held as merchant plant as ordered by the NMPRC (Note 16). PNM has entered into agreements to sell the power from 36 MW of that capacity to a third party at a fixed price for the period January 1, 2018 through June 30, 2022, subject to certain conditions. Under these agreements, PNM is obligated to deliver 36 MW of power only when SJGS Unit 4 is operating. These agreements are not considered derivatives because there is no notional amount due to the unit-contingent nature of the transactions.

PNM's operations are managed primarily through a net asset-backed strategy, whereby PNM's aggregate net open forward contract position is covered by its forecasted excess generation capabilities or market purchases. PNM could be exposed to market risk if its generation capabilities were to be disrupted or if its load requirements were to be greater than anticipated. If all or a portion of load requirements were required to be covered as a result of such unexpected situations, commitments would have to be met through market purchases. TNMP does not enter into energy related derivative contracts.

Commodity Risk

Marketing and procurement of energy often involve market risks associated with managing energy commodities and establishing positions in the energy markets, primarily on a short-term basis. PNM routinely enters into various derivative instruments such as forward contracts, option agreements, and price basis swap agreements to economically hedge price and volume risk on power commitments and fuel requirements and to minimize the effect of market fluctuations in wholesale portfolios. PNM monitors the market risk of its commodity contracts to maintain total exposure within management-prescribed limits in accordance with approved risk and credit policies.

Accounting for Derivatives

Under derivative accounting and related rules for energy contracts, PNM accounts for its various instruments for the purchase and sale of energy, which meet the definition of a derivative, based on PNM's intent. During the years ended December 31, 2017, 2016, and 2015, PNM was not hedging its exposure to the variability in future cash flows from commodity derivatives through designated cash flows hedges. The derivative contracts recorded at fair value that do not qualify or are not designated for cash flow hedge accounting are classified as economic hedges. Economic hedges are defined as derivative instruments, including long-term power agreements, used to economically hedge generation assets, purchased power and fuel costs, and customer load requirements. Changes in the fair value of economic hedges are reflected in results of operations and are classified between operating revenues and cost of energy according to the intent of the hedge. PNM has no trading transactions.

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S&P Global Market Intelligence

Commodity Derivatives

PNM's commodity derivative instruments that are recorded at fair value, all of which are accounted for as economic hedges, are summarized as follows:

	Economic Hedges	
	December 31,	
	2017	2016
	(In thousands)	
Current assets	$ 1,088	$ 5,224
Deferred charges	3,556	—
	4,644	5,224
Current liabilities	(1,182)	(2,339)
Long-term liabilities	(3,556)	—
	(4,738)	(2,339)
Net	$ (94)	$ 2,885

Included in the above table are $2.7 million of current assets at December 31, 2016 related to contracts for the sale of energy from PVNGS Unit 3 through 2017 at market price plus a premium. As noted above, PVNGS Unit 3 has become a jurisdictional resource to serve New Mexico retail customers beginning January 1, 2018. Certain of PNM's commodity derivative instruments in the above table are subject to master netting agreements whereby assets and liabilities could be offset in the settlement process. PNM does not offset fair value and cash collateral for derivative instruments under master netting arrangements and the above table reflects the gross amounts of fair value assets and liabilities for commodity derivatives. Included in the above table are equal amounts of assets and liabilities aggregating $4.6 million at December 31, 2017 and $0.5 million at December 31, 2016, resulting from PNM's hazard sharing arrangements with Tri-State (Note 17). The hazard sharing arrangements are net-settled upon delivery. Other amounts that could be offset under master netting agreements were immaterial.

At December 31, 2017 and 2016, PNM had no amounts recognized for the legal right to reclaim cash collateral. However, at December 31, 2017 and 2016, amounts posted as cash collateral under margin arrangements were $0.8 million and $2.6 million. At December 31, 2017 and 2016, obligations to return cash collateral were $0.9 million and $0.1 million. Cash collateral amounts are included in other current assets and other current liabilities on the Consolidated Balance Sheets.

PNM has a NMPRC-approved hedging plan to manage fuel and purchased power costs related to customers covered by its FPPAC. There were no amounts hedged under this plan as of December 31, 2017. The table above includes $0.2 million of current assets and $0.1 million of current liabilities at December 31, 2016 related to this plan. The offsets to these amounts are recorded as regulatory assets and liabilities on the Consolidated Balance Sheets.

The following table presents the effect of mark-to-market commodity derivative instruments on PNM's earnings, excluding income tax effects. Commodity derivatives had no impact on OCI for the periods presented.

	Economic Hedges		
	Year Ended December 31,		
	2017	2016	2015

	(In thousands)		
Electric operating revenues	$ 5,151	$ (53)	$ 7,156
Cost of energy	(5,386)	(1,208)	(293)
Total gain (loss)	$ (235)	$ (1,261)	$ 6,863

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Commodity contract volume positions are presented in MMBTU for gas related contracts and in MWh for power related contracts. The table below presents PNM's net buy (sell) volume positions:

	Economic Hedges	
	MMBTU	MWh
December 31, 2017	100,000	—
December 31, 2016	254,100	(2,471,600)

PNM has contingent requirements to provide collateral under commodity contracts having an objectively determinable collateral provision that are in net liability positions and are not fully collateralized with cash. In connection with managing its commodity risks, PNM enters into master agreements with certain counterparties. If PNM is in a net liability position under an agreement, some agreements provide that the counterparties can request collateral if PNM's credit rating is downgraded; other agreements provide that the counterparty may request collateral to provide it with "adequate assurance" that PNM will perform; and others have no provision for collateral. At December 31, 2017 and 2016, PNM had no such contracts in a net liability position.

Non-Derivative Financial Instruments

The carrying amounts reflected on the Consolidated Balance Sheets approximate fair value for cash, receivables, and payables due to the short period of maturity. Available-for-sale securities are carried at fair value. Available-for-sale securities consist of PNM assets held in the NDT for its share of decommissioning costs of PVNGS and trusts for PNM's share of final reclamation costs related to the coal mines serving SJGS and Four Corners (Note 16). At December 31, 2017 and 2016, the fair value of available-for-sale securities included $293.7 million and $253.9 million for the NDT and $29.8 million and $19.1 million for the mine reclamation trusts. The fair value and gross unrealized gains of investments in available-for-sale securities are presented in the following table.

	December 31, 2017		December 31, 2016	
	Unrealized Gains	Fair Value	Unrealized Gains	Fair Value
	(In thousands)			
Cash and cash equivalents	$ —	$ 52,636	$ —	$ 23,683
Equity securities:				
Domestic value	4,011	40,032	1,135	34,796
Domestic growth	3,995	35,456	3,032	47,595
International and other	6,810	45,867	2,029	27,481
Fixed income securities:				
U.S. Government	273	34,317	115	40,962
Municipals	1,225	48,076	585	43,789
Corporate and other	1,714	67,140	553	54,671
	$ 18,028	$ 323,524	$ 7,449	$ 272,977

Due to the funded status of the nuclear decommissioning trust and overall market performance, PNM began to re-balance the decommissioning investment portfolio in late 2017 to increase the percentage of the investments in fixed income (debt) securities to approximately 85%. The portfolio re-balancing was completed in early 2018.

The proceeds and gross realized gains and losses on the disposition of available-for-sale securities are shown in the following table. Realized gains and losses are determined by specific identification of costs of securities sold. Gross realized losses shown below exclude the (increase)/decrease in realized impairment losses of $3.3 million, $(1.2) million, and $(4.3) million for the years ended December 31, 2017, 2016 and 2015. See New Accounting Pronouncements in Note 1.

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	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Proceeds from sales	$ 637,492	$ 522,601	$ 252,174
Gross realized gains	$ 36,896	$ 46,116	$ 29,663

Gross realized (losses)	$ (12,993)	$ (25,430)	$ (9,259)

Held-to-maturity securities are those investments in debt securities that the Company has the ability and intent to hold until maturity. At December 31, 2017 and 2016, PNMR's held-to-maturity securities consist of the Westmoreland Loan.

The Company has no available-for-sale or held-to-maturity securities for which carrying value exceeds fair value. There are no impairments considered to be "other than temporary" that are included in AOCI and not recognized in earnings.

At December 31, 2017, the available-for-sale and held-to-maturity debt securities had the following final maturities:

	Fair Value	
	Available-for-Sale	Held-to-Maturity
	PNMR and PNM	PNMR
	(In thousands)	
Within 1 year	$ 4,460	$ —
After 1 year through 5 years	32,693	66,588
After 5 years through 10 years	48,681	—
After 10 years through 15 years	5,934	—
After 15 years through 20 years	11,983	—
After 20 years	45,782	—
	$ 149,533	$ 66,588

Fair Value Disclosures

The Company determines the fair values of its derivative and other financial instruments based on the hierarchy established in GAAP, which requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. GAAP describes three levels of inputs that may be used to measure fair value. Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability. Level 3 inputs used in determining fair values for the Company consist of internal valuation models. The Company records any transfers between fair value hierarchy levels as of the end of each calendar quarter. There were no transfers between levels during the years ended December 31, 2017 and 2016.

For available-for-sale securities, Level 2 fair values are provided by the trustee utilizing a pricing service. The pricing provider predominantly uses the market approach using bid side market value based upon a hierarchy of information for specific securities or securities with similar characteristics. For commodity derivatives, Level 2 fair values are determined based on market observable inputs, which are validated using multiple broker quotes, including forward price, volatility, and interest rate curves to establish expectations of future prices. Credit valuation adjustments are made for estimated credit losses based on the overall exposure to each counterparty. For the Company's long-term debt, Level 2 fair values are provided by an external pricing service. The pricing service primarily utilizes quoted prices for similar debt in active markets when determining fair value. For investments categorized as Level 3, primarily the Westmoreland Loan, fair values were determined by discounted cash flow models that take into consideration discount rates that are observable for similar types of assets and liabilities. Management of the Company independently verifies the information provided by pricing services.

Items recorded at fair value by PNM on the Consolidated Balance Sheets are presented below by level of the fair value hierarchy. There were no Level 3 fair value measurements at December 31, 2017 and 2016 for items recorded at fair value.

		GAAP Fair Value Hierarchy	
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)
		(In thousands)	
December 31, 2017			
Available-for-sale securities			
Cash and cash equivalents	$ 52,636	$ 52,636	$ —
Equity securities:			
Domestic value	40,032	40,032	—
Domestic growth	35,456	35,456	—
International and other	45,867	42,332	3,535
Fixed income securities:			
U.S. Government	34,317	33,645	672
Municipals	48,076	—	48,076
Corporate and other	67,140	—	67,140
	$ 323,524	$ 204,101	$ 119,423
Commodity derivative assets	$ 4,644	$ —	$ 4,644
Commodity derivative liabilities	(4,738)	—	(4,738)
Net	$ (94)	$ —	$ (94)

December 31, 2016

Available-for-sale securities			
Cash and cash equivalents	$ 23,683	$ 23,683	$ —
Equity securities:			
Domestic value	34,796	34,796	—
Domestic growth	47,595	47,595	—
International and other	27,481	27,481	—
Fixed income securities:			
U.S. Government	40,962	39,723	1,239
Municipals	43,789	—	43,789
Corporate and other	54,671	23,158	31,513
	$ 272,977	$ 196,436	$ 76,541
Commodity derivative assets	$ 5,224	$ —	$ 5,224
Commodity derivative liabilities	(2,339)	—	(2,339)
Net	$ 2,885	$ —	$ 2,885

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The carrying amounts and fair values of investments in the Westmoreland Loan, other investments, and long-term debt, which are not recorded at fair value on the Consolidated Balance Sheets are presented below:

			GAAP Fair Value Hierarchy		
	Carrying Amount	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
December 31, 2017			(In thousands)		
PNMR					
Long-term debt	$ 2,437,645	$ 2,554,836	$ —	$ 2,554,836	$ —
Westmoreland Loan	$ 56,640	$ 66,588	$ —	$ —	$ 66,588
Other investments	$ 503	$ 503	$ 503	$ —	$ —
PNM					
Long-term debt	$ 1,657,910	$ 1,727,135	$ —	$ 1,727,135	$ —
Other investments	$ 283	$ 283	$ 283	$ —	$ —
TNMP					
Long-term debt	$ 480,620	$ 527,563	$ —	$ 527,563	$ —
Other investments	$ 220	$ 220	$ 220	$ —	$ —
December 31, 2016					
PNMR					
Long-term debt	$ 2,392,712	$ 2,540,693	$ —	$ 2,540,693	$ —
Westmoreland Loan	$ 95,000	$ 100,893	$ —	$ —	$ 100,893
Other investments	$ 547	$ 1,164	$ 547	$ —	$ 617
PNM					
Long-term debt	$ 1,631,369	$ 1,730,157	$ —	$ 1,730,157	$ —
Other investments	$ 316	$ 316	$ 316	$ —	$ —
TNMP					
Long-term debt	$ 420,875	$ 468,329	$ —	$ 468,329	$ —
Other investments	$ 231	$ 231	$ 231	$ —	$ —

Investments Held by Employee Benefit Plans

As discussed in Note 12, PNM and TNMP have trusts that hold investment assets for their pension and other postretirement benefit plans. The fair value of the assets held by the trusts impacts the determination of the funded status of each plan (Note 12), but the assets are not reflected on the Company's Consolidated Balance Sheets. Both the PNM Pension Plan and the TNMP Pension Plan hold units of participation in the PNM Resources, Inc. Master Trust (the "PNMR Master Trust"), which was established for the investment of assets of the pension plans. The Company is contemplating changing its investment allocation targets by decreasing the fixed income investments used to match pension liabilities from 65% to 50% beginning in 2018.

GAAP provides a practical expedient that allows the net asset value per share to be used as fair value for investments in certain entities that do not have readily determinable fair values and are considered to be investment companies. Fair values for alternative investments held by the PNMR Master Trust are valued using this practical expedient. Under GAAP, investments for which fair value is measured using that practical expedient are not required to be categorized within the fair value hierarchy. Level 2 and Level 3 fair values are provided by fund managers utilizing a pricing service. For level 2 fair values, the pricing provider predominately uses the market approach using bid side market value based upon a hierarchy of information for specific securities or securities with similar characteristics. Fair values of Level 2 investments in mutual funds are equal to net asset value as of year-end. Level 3 investments are comprised of corporate term loans. Alternative investments include private equity funds, hedge funds, and real estate funds. The private equity funds are not voluntarily redeemable. These investments are realized through periodic distributions occurring over a 10 to 15 year term after the initial investment. The real estate funds and hedge funds may

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be voluntarily redeemed, but are subject to redemption provisions that may result in the funds not being able to be redeemed in the near term. Audited financial statements are received for each fund and are reviewed by the Company annually.

The valuation of Level 3 investments and alternative investments requires significant judgment by the pricing provider due to the absence of quoted market values, changes in market conditions, and the long-term nature of the assets. The significant unobservable inputs include the trading multiples of public companies that are considered comparable to the company being valued, company specific issues, estimates of liquidation value, current operating performance and future expectations of performance, changes in market outlook and the financing environment, capitalization rates, discount rates, and cash flows. The fair values of investments held by the employee benefit plans are as follows:

		GAAP Fair Value Hierarchy		
	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
December 31, 2017		(In thousands)		
PNM Pension Plan				
Participation in PNMR Master Trust Investments:				
Investments categorized within fair value hierarchy	$ 487,498	$ 140,218	$ 347,089	$ 191
Uncategorized investments	74,768			
Total Master Trust Investments	$ 562,266			
TNMP Pension Plan				
Participation in PNMR Master Trust Investments:				
Investments categorized within fair value hierarchy	$ 53,273	$ 15,244	$ 38,008	$ 21
Uncategorized investments	10,260			
Total Master Trust Investments	$ 63,533			
PNM OPEB Plan				
Cash and cash equivalents	$ 437	$ 437	$ —	$ —
Equity securities:				
International funds	10,636	—	10,636	—
Domestic value	10,816	10,816	—	—
Domestic growth	6,710	6,710	—	—
Other funds	31,660	—	31,660	—
Fixed income securities:				
Mutual funds	20,918	20,918	—	—
	$ 81,177	$ 38,881	$ 42,296	$ —
TNMP OPEB Plan				
Cash and cash equivalents	$ 149	$ 149	$ —	$ —
Equity securities:				
International funds	1,597	—	1,597	—
Domestic value	293	293	—	—
Domestic growth	1,410	1,410	—	—
Other funds	4,011	—	4,011	—
Fixed income securities:				
Mutual funds	2,685	2,685	—	—
	$ 10,145	$ 4,537	$ 5,608	$ —

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	GAAP Fair Value Hierarchy		
	Quoted Prices in Active Markets for Identical	Significant Other Observable	Significant Unobservable

December 31, 2016	Total	Assets (Level 1)	Inputs (Level 2)	Inputs (Level 3)
		(In thousands)		
PNM Pension Plan				
Participation in PNMR Master Trust Investments:				
Investments categorized within fair value hierarchy	$ 467,965	$ 129,624	$ 337,989	$ 352
Uncategorized investments	75,685			
Total Master Trust Investments	$ 543,650			
TNMP Pension Plan				
Participation in PNMR Master Trust Investments:				
Investments categorized within fair value hierarchy	$ 50,901	$ 14,447	$ 36,416	$ 38
Uncategorized investments	9,729			
Total Master Trust Investments	$ 60,630			
PNM OPEB Plan				
Cash and cash equivalents	$ 2,567	$ 2,567	$ —	$ —
Equity securities:				
International funds	9,300	—	9,300	—
Domestic value	10,260	10,260	—	—
Domestic growth	6,338	6,338	—	—
Other funds	26,405	—	26,405	—
Fixed income securities:				
Mutual funds	18,959	18,959	—	—
	$ 73,829	$ 38,124	$ 35,705	$ —
TNMP OPEB Plan				
Cash and cash equivalents	$ 308	$ 308	$ —	$ —
Equity securities:				
International funds	1,279	—	1,279	—
Domestic value	449	449	—	—
Domestic growth	1,089	1,089	—	—
Other funds	3,060	—	3,060	—
Fixed income securities:				
Mutual funds	2,593	2,593	—	—
	$ 8,778	$ 4,439	$ 4,339	$ —

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The fair values of investments in the PNMR Master Trust are as follows:

December 31, 2017	Total	GAAP Fair Value Hierarchy: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(In thousands)		
PNMR Master Trust				
Cash and cash equivalents	$ 7,697	$ 7,697	$ —	$ —
Equity securities:				
International	42,048	—	42,048	—
Domestic value	37,026	37,026	—	—
Domestic growth	19,136	19,136	—	—
Other funds	25,099	—	25,099	—
Fixed income securities:				
Corporate	215,535	—	215,323	212
U.S. Government	117,572	91,603	25,969	—
Municipals	11,438	—	11,438	—
Other funds	65,220	—	65,220	—
Total investments categorized within fair value hierarchy	540,771	$ 155,462	$ 385,097	$ 212

Uncategorized investments:				
Private equity funds	22,281			
Hedge funds	45,615			
Real estate funds	17,132			
	$ 625,799			
December 31, 2016				
PNMR Master Trust				
Cash and cash equivalents	$ 20,503	$ 20,503	$ —	$ —
Equity securities:				
International	38,401	—	38,401	—
Domestic value	36,036	36,036	—	—
Domestic growth	18,484	18,484	—	—
Other funds	27,532	—	27,532	—
Fixed income securities:				
Corporate	205,419	—	205,029	390
U.S. Government	94,359	69,048	25,311	—
Municipals	13,970	—	13,970	—
Other funds	64,162	—	64,162	—
Total investments categorized within fair value hierarchy	518,866	$ 144,071	$ 374,405	$ 390
Uncategorized investments:				
Private equity funds	27,060			
Hedge funds	42,070			
Real estate funds	16,284			
	$ 604,280			

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A reconciliation of the changes in Level 3 fair value measurements is as follows:

PNMR Master Trust	Fixed Income - Corporate		
	PNM Pension	TNMP Pension	Total Master Trust
	(In thousands)		
Balance at December 31, 2015	$ 719	$ 78	$ 797
Actual return on assets sold during the period	1	—	1
Actual return on assets still held at period end	19	2	21
Purchases	—	—	—
Sales	(387)	(42)	(429)
Balance at December 31, 2016	352	38	390
Actual return on assets sold during the period	1	—	1
Actual return on assets still held at period end	(7)	(1)	(8)
Purchases	92	10	102
Sales	(247)	(26)	(273)
Balance at December 31, 2017	$ 191	$ 21	$ 212

(9) Variable Interest Entities

GAAP determines how an enterprise evaluates and accounts for its involvement with variable interest entities, focusing primarily on whether the enterprise has the power to direct the activities that most significantly impact the economic performance of a variable interest entity ("VIE"). GAAP also requires continual reassessment of the primary beneficiary of a VIE.

Valencia

PNM has a PPA to purchase all of the electric capacity and energy from Valencia, a 158 MW natural gas-fired power plant near Belen, New Mexico, through May 2028. A third party built, owns, and operates the facility while PNM is the sole purchaser of the electricity generated. PNM is obligated to pay fixed operation and maintenance and capacity charges in addition to variable operation and maintenance charges under this PPA. For the years ended December 31, 2017, 2016, and 2015, PNM paid $19.6 million, $19.3 million, and $19.2 million for fixed charges and $1.3 million, $1.1 million, and $1.6 million for variable charges. PNM does not have any other financial obligations related to Valencia. The assets of Valencia can only be used to satisfy its obligations and creditors of Valencia do not have any recourse against PNM's assets. During the term of the PPA, PNM has the option, under certain conditions, to purchase and own up to 50% of the plant or the VIE. The PPA specifies that the purchase price would be the greater of 50% of book value reduced by related indebtedness or 50% of fair market value.

PNM sources fuel for the plant, controls when the facility operates through its dispatch, and receives the entire output of the plant, which factors directly and significantly impact the economic performance of Valencia. Therefore, PNM has concluded that the third-party entity that owns Valencia is a VIE and that PNM is the primary beneficiary of the entity under GAAP since PNM has the power to direct the activities that most significantly impact the economic performance of Valencia and will absorb the majority of the variability in the cash flows of the plant. As the primary beneficiary, PNM consolidates Valencia in its financial statements. Accordingly, the assets, liabilities, operating expenses, and cash flows of Valencia

are included in the Consolidated Financial Statements of PNM although PNM has no legal ownership interest or voting control of the VIE. The assets and liabilities of Valencia set forth below are immaterial to PNM and, therefore, not shown separately on the Consolidated Balance Sheets. The owner's equity and net income of Valencia are considered attributable to non-controlling interest.

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Summarized financial information for Valencia is as follows:

Results of Operations

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Operating revenues	$ 20,887	$ 20,371	$ 20,687
Operating expenses	(5,870)	(5,852)	(5,777)
Earnings attributable to non-controlling interest	$ 15,017	$ 14,519	$ 14,910

Financial Position

	December 31,	
	2017	2016
	(In thousands)	
Current assets	$ 2,688	$ 2,551
Net property, plant and equipment	64,109	66,947
Total assets	66,797	69,498
Current liabilities	602	578
Owners' equity – non-controlling interest	$ 66,195	$ 68,920

Westmoreland San Juan LLC ("WSJ") and SJCC

As discussed in the subheading Coal Supply in Note 16, PNM purchases coal for SJGS from SJCC under a coal supply agreement ("SJGS CSA"). That section includes information on the acquisition of SJCC by WSJ, a subsidiary of Westmoreland, on January 31, 2016, as well as a $125.0 million loan (the "Westmoreland Loan") from NM Capital, a subsidiary of PNMR, to WSJ, which loan provided substantially all of the funds required for the SJCC purchase, and the issuance of $30.3 million in letters of credit to facilitate the issuance of reclamation bonds required in order for SJCC to mine coal to be supplied to SJGS. The Westmoreland Loan and the letters of credit support result in PNMR being considered to have a variable interest in WSJ, including its subsidiary, SJCC, since PNMR and NM Capital could be subject to possible loss in the event of a default by WSJ under the Westmoreland Loan and/or performance was required under the letter of credit support. Principal payments under the Westmoreland Loan began on August 1, 2016 and are required quarterly thereafter. Interest is also paid quarterly beginning on May 3, 2016.

At December 31, 2017, the amount outstanding under the Westmoreland Loan was $56.6 million. In addition, interest receivable of $1.0 million is included in Other receivables. The Westmoreland Loan requires that all cash flows of WSJ, in excess of normal operating expenses, capital additions, and operating reserves, be utilized for principal and interest payments under the loan until it is fully repaid. As of February 20, 2018, the amount outstanding under the Westmoreland Loan was $51.0 million, reflecting the February 1, 2018 principal payment of $5.6 million. The Westmoreland Loan is secured by the assets of and the equity interests in SJCC. In the event of a default by WSJ, NM Capital would have the ability to take over the mining operations. In such event, NM Capital would likely engage a third-party mining company to operate SJCC so that operations of the mine are not disrupted. The acquisition of SJCC for approximately $125.0 million on January 31, 2016 was an arm's-length negotiated transaction between Westmoreland and BHP, which amount should approximate the fair value of SJCC at the date of acquisition. If WSJ were to default, NM Capital should be able to acquire assets of approximately the value of the Westmoreland Loan without a significant loss. Furthermore, PNMR considers the possibility of loss under the letters of credit support to be remote since the purpose of posting the bonds is to provide assurance that SJCC performs the required reclamation of the mine site in accordance with applicable regulations and all reclamation costs are reimbursable under the SJGS CSA. Also, much of the mine reclamation activities will not be performed until after the expiration of the SJGS CSA and the final maturity of the Westmoreland Loan. In addition, each of the SJGS participants has established and funds a trust to meet its future reclamation obligations.

Both WSJ and SJCC are considered to be VIEs. PNMR's analysis of these arrangements concluded that Westmoreland, as the parent of WSJ, has the ability to direct the SJCC mining operations, which is the factor that most significantly impacts the economic performance of WSJ and SJCC. NM Capital's rights under the Westmoreland Loan are the typical protective rights of

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a lender, but do not give NM Capital any oversight over mining operations unless there is a default under the loan agreement. Other than PNM being able to ensure that coal is supplied in adequate quantities and of sufficient quality to provide the fuel necessary to operate SJGS in a normal manner, the mining operations are solely under the control of Westmoreland and its subsidiaries, including developing mining plans, hiring of personnel, and incurring operating and maintenance expenses. Neither PNMR nor PNM has any ability to direct or influence the mining operation. Therefore, PNM's involvement through the SJGS CSA is a protective right rather than a participating right and Westmoreland has the power to direct the activities that most significantly impact the economic performance of SJCC. The SJGS CSA requires SJCC to deliver coal required to fuel SJGS in exchange for payment of a set price per ton, which

is escalated over time for inflation. If SJCC is able to mine more efficiently than anticipated, its economic performance will be improved. Conversely, if SJCC cannot mine as efficiently as anticipated, its economic performance will be negatively impacted. Accordingly, PNMR believes Westmoreland is the primary beneficiary of WSJ and, therefore, WSJ and SJCC are not consolidated by either PNMR or PNM. The amounts outstanding under the Westmoreland Loan and the letter of credit support constitute PNMR's maximum exposure to loss from the VIEs.

PVNGS Leases

PNM leased portions of its interests in Units 1 and 2 of PVNGS under leases, which initially were scheduled to expire on January 15, 2015 for the four Unit 1 leases and January 15, 2016 for the four Unit 2 leases. See Note 7 for additional information regarding the leases and actions PNM has taken with respect to its renewal and purchase options. Each of the lease agreements was with a different trust whose beneficial owners were five different institutional investors. PNM is not the legal or tax owner of the leased assets. The beneficial owners of the trusts possess all of the voting control and pecuniary interests in the trusts. At January 15, 2015, the four Unit 1 leases were extended. At January 15, 2016, one of the Unit 2 leases was extended and PNM purchased the assets underlying the other three Unit 2 leases. See Note 17 for information concerning the NMPRC's treatment of the purchased assets and extended leases in PNM's NM 2015 Rate Case. PNM is only obligated to make payments to the trusts for the scheduled semi-annual lease payments and has no other financial obligations or commitments to the trusts or the beneficial owners although PNM is responsible for all decommissioning obligations related to its entire interest in PVNGS both during and after termination of the leases. Creditors of the trusts have no recourse to PNM's assets other than with respect to the contractual lease payments. PNM has no additional rights to the assets of the trusts other than the use of the leased assets. PNM has no assets or liabilities recorded on its Consolidated Balance Sheets related to the trusts other than accrued lease payments of $8.3 million at December 31, 2017 and 2016, which are included in other current liabilities on the Consolidated Balance Sheets.

Prior to their exercise or expiration, the fixed rate renewal options were considered to be variable interests in the trusts and resulted in the trusts being considered variable interest entities under GAAP. Upon execution of documents establishing terms of the asset purchases or lease extensions, the fixed rate renewal options ceased to exist as did PNM's variable interest in the trusts. PNM evaluated the PVNGS lease arrangements, including actions taken with respect to the renewal and purchase options, and concluded that it did not have the power to direct the activities that most significantly impacted the economic performance of the trusts and, therefore, was not the primary beneficiary of the trusts under GAAP. The significant factors considered in reaching this conclusion were: the periods covered by fixed price renewal options were significantly shorter than the anticipated remaining useful lives of the assets since the operating licenses for the plants were extended for 20 years through 2045 for Unit 1 and 2046 for Unit 2; PNM's only financial obligation to the trusts is to make the fixed lease payments and the payments do not vary based on the output of the plants or their performance; during the lease terms, the economic performance of the trusts is substantially fixed due to the fixed lease payments; PNM is only one of several participants in PVNGS and is not the operating agent for the plants, so does not significantly influence the day-to-day operations of the plants; the operations of the plants, including plans for their decommissioning, are highly regulated by the NRC, leaving little room for the participants to operate the plants in a manner that impacts the economic performance of the trusts; the economic performance of the trusts at the end of the lease terms is dependent upon the fair value and remaining lives of the plants at that time, which are determined by factors such as power prices, outlook for nuclear power, and the impacts of potential carbon legislation or regulation, all which are outside of PNM's control; and while PNM had some benefit from its renewal options, the vast majority of the value at the end of the leases would accrue to the beneficial owners of the trusts, particularly given increases in the value of existing nuclear generating facilities, which have no GHG, resulting from potential carbon legislation or regulation.

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(10) Earnings and Dividends Per Share

In accordance with GAAP, dual presentation of basic and diluted earnings per share has been presented in the Consolidated Statements of Earnings of PNMR. Information regarding the computation of earnings per share and dividends per share is as follows:

	Year Ended December 31,		
	2017	2016	2015
	(In thousands, except per share amounts)		
Net Earnings Attributable to PNMR	$ 79,874	$ 116,849	$ 15,640
Average Number of Common Shares:			
Outstanding during year	79,654	79,654	79,654
Vested awards of restricted stock	237	104	105
Average Shares – Basic	79,891	79,758	79,759
Dilutive Effect of Common Stock Equivalents:			
Stock options and restricted stock	250	374	380
Average Shares – Diluted	80,141	80,132	80,139
Net Earnings Attributable to PNMR Per Share of Common Stock:			
Basic	$ 1.00	$ 1.47	$ 0.20
Diluted	$ 1.00	$ 1.46	$ 0.20
Dividends Declared per Common Share	$ 0.9925	$ 0.9025	$ 0.8200

(11) Income Taxes

Federal Income Tax Reform

On December 22, 2017, comprehensive changes in United States federal income taxes were enacted through legislation commonly known as the Tax Cuts and Jobs Act (the "Tax Act"). The Tax Act makes many significant modifications to the tax laws, including reducing the federal corporate income tax rate from 35% to 21% effective January 1, 2018. The Tax Act also eliminates federal bonus depreciation for utilities effective September 28, 2017 and, effective January 1, 2018, limits interest deductibility for non-utility businesses and limits the deductibility of certain officer compensation.

Although most of the provisions of the Tax Act are not effective until 2018, GAAP requires that some effects must be recognized in 2017. Under the asset and liability method of accounting for income taxes used by the Company, deferred tax assets and liabilities are recognized for the future tax consequences of temporary differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. The deferred tax assets and liabilities are measured using the enacted tax rates expected to

apply to taxable income in the years in which the temporary differences are expected to reverse. At the date of enactment of the Tax Act, the Company had net deferred tax liabilities for its regulated activities and net deferred tax assets for non-regulated activities. As a result of the change in the federal income tax rate, the Company re-measured and adjusted its deferred tax assets and liabilities as of December 31, 2017. The portion of that adjustment not related to PNM's and TNMP's regulated activities was recorded as a reduction in net deferred tax assets and an increase in income tax expense. The portion related to PNM's and TNMP's regulated activities was recorded as a reduction in net deferred tax liabilities and an increase in regulatory liabilities, based on the assumption that PNM and TNMP will be required to return the benefit to ratepayers over time. PNM's NM 2016 Rate Case (Note 17) reflects that assumption by including an amortization of the estimated benefit of the reduction in existing deferred federal income taxes as a reduction to customer rates over a twenty-one year period beginning in 2018. In addition, in January 2018, the PUCT issued an order requiring Texas utilities, including TNMP, to begin recording regulatory liabilities for the effects of the Tax Act with the stated purpose of reflecting those effects in the utility bills of Texas ratepayers.

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In December 2017, the SEC issued Staff Accounting Bulletin No. 118, which provides guidance to address the application of GAAP to reflect the Tax Act in circumstances where all information and analysis of the Tax Act is not yet available or complete. This bulletin provides for up to a one-year period in which to complete the required analyses and accounting for the impacts of the Tax Act. The Company believes it has made reasonable estimates of the effects of the Tax Act and reflected the impacts in the Consolidated Financial Statements. However, the reported effects on the Company's deferred tax assets and liabilities, regulatory assets and liabilities, and income tax expense are provisional and it is possible that changes to U.S. Treasury regulations, IRS interpretations of the provisions of the Tax Act, actions by the NMPRC, PUCT, and FERC, or the Company's further analysis of historical records could cause these estimates to change.

The adjustments to deferred income taxes recorded as increases in regulatory liabilities and income tax expense as a result of the enactment of the Tax Act are presented below:

	PNM	TNMP	Corporate and Other	Consolidated
		(In thousands)		
Net increase in regulatory liabilities	$ 402,501	$ 146,451	$ —	$ 548,952
Net decrease in deferred income tax liabilities (deferred income tax assets)	372,895	138,586	(19,990)	491,491
Net deferred income tax expense	$ 29,606	$ 7,865	$ 19,990	$ 57,461

GAAP requires that the impacts of adjusting existing deferred tax assets and liabilities for a change in an income tax rate be recognized in income tax expense during the period of enactment, including impacts that are reflected in AOCI. This results in the tax effects of items within AOCI not reflecting the appropriate tax rate and being stranded in AOCI. In February 2018, the FASB issued *Accounting Standards Update 2018-02 - Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income* to address this issue by allowing entities to reclassify the income tax effects of the Tax Act on items within AOCI to retained earnings. The Company records in AOCI, net of income taxes, unamortized gains and losses related to PNM's defined benefit pension plans to the extent not attributed to regulated operations, unrealized gains on PNM's available-for-sale securities, and unrealized gains and losses on cash flow hedges related to PNMR's interest rate swaps. When amounts are reclassified from AOCI to the Consolidated Statement of Earnings, the Company recognizes the related income tax expense (benefit) at the tax rate in effect at that time. As permitted by ASU 2018-02, as of December 31, 2017, the Company reclassified the stranded federal income tax effects of the Tax Act on items recorded in AOCI, resulting in a net increase in retained earnings of $17.6 million. See Note 19.

PNMR

PNMR's income taxes consist of the following components:

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Current federal income tax	$ —	$ —	$ —
Current state income tax	(188)	(527)	(1,376)
Deferred federal income tax	119,182	60,892	5,488
Deferred state income tax	11,632	3,886	12,305
Amortization of accumulated investment tax credits	(286)	(973)	(1,342)
Total income taxes	$ 130,340	$ 63,278	$ 15,075

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PNMR's provision for income taxes differed from the federal income tax computed at the statutory rate for each of the years shown. The differences are attributable to the following factors:

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Federal income tax at statutory rates	$ 79,016	$ 68,311	$ 16,154

Amortization of accumulated investment tax credits	(286)	(973)	(1,342)
Flow-through of depreciation items	1,147	1,227	1,485
Earnings attributable to non-controlling interest in Valencia	(5,256)	(5,082)	(5,218)
State income tax, net of federal benefit	5,398	4,537	(1,781)
Impairment of state net operating loss carryforwards	819	(311)	5,278
Impairment of state production tax credits	—	—	3,092
Allowance for equity funds used during construction	(3,331)	(1,732)	(3,650)
Reversal of deferred items related to BART at SJGS	—	—	1,826
Impairment of charitable contribution carryforward	909	—	2,042
Regulatory recovery of prior year impairments of state net operating loss carryforward, net of amortization	(2,225)	(1,877)	—
Federal income tax rate change	57,461	—	—
Excess tax benefits related to stock compensation awards	(2,324)	—	—
Other	(988)	(822)	(2,811)
Total income taxes	$ 130,340	$ 63,278	$ 15,075
Effective tax rate	57.73%	32.42%	32.66%

The components of PNMR's net accumulated deferred income tax liability were:

	December 31,	
	2017	2016
	(In thousands)	
Deferred tax assets:		
Net operating loss	$ 98,301	$ 160,901
Regulatory liabilities related to income taxes	189,501	64,657
Federal tax credit carryforwards	71,849	78,675
Shutdown of SJGS Units 2 and 3	2,204	53,434
Other	45,656	75,805
Total deferred tax assets	407,511	433,472
Deferred tax liabilities:		
Depreciation and plant related	(690,909)	(1,102,458)
Investment tax credit	(55,731)	(56,017)
Regulatory assets related to income taxes	(61,956)	(66,378)
CTC	(5,670)	(12,715)
Pension	(56,070)	(57,287)
Regulatory asset for shutdown of SJGS Units 2 and 3	(31,887)	—
Other	(52,498)	(79,267)
Total deferred tax liabilities	(954,721)	(1,374,122)
Net accumulated deferred income tax liabilities	$ (547,210)	$ (940,650)

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The following table reconciles the change in PNMR's net accumulated deferred income tax liability to the deferred income tax benefit included in the Consolidated Statement of Earnings:

	Year Ended December 31, 2017
	(In thousands)
Net change in deferred income tax liability per above table	$ (393,440)
Change in tax effects of income tax related regulatory assets and liabilities	(16,444)
Tax effect of mark-to-market adjustments	(4,724)
Tax effect of excess pension liability	(3,421)
Adjustment for uncertain income tax positions	2,677
Reclassification of unrecognized tax benefits	(2,677)
Regulatory recovery of prior year impairments of state net operating loss carryforward, net of amortization	(2,225)
Federal income tax rate change	548,952
Cumulative effect adjustment for excess tax benefit related to stock compensation awards	10,382
Alternative minimum tax carryforward reclassified to receivable	(8,336)
Other	(216)
Deferred income taxes	$ 130,528

PNM

PNM's income taxes (benefit) consist of the following components:

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Current federal income tax	$ 118	$ (10,290)	$ (7,934)
Current state income tax	(1,112)	(1,907)	(1,988)
Deferred federal income tax	73,308	49,123	(6,827)
Deferred state income tax	9,527	4,969	5,333
Amortization of accumulated investment tax credits	(286)	(973)	(1,342)
Total income taxes (benefit)	$ 81,555	$ 40,922	$ (12,758)

PNM RESOURCES, INC. AND SUBSIDIARIES
PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES
TEXAS-NEW MEXICO POWER COMPANY AND SUBSIDIARIES

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PNM's provision for income taxes (benefit) differed from the federal income tax computed at the statutory rate for each of the years shown. The differences are attributable to the following factors:

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Federal income tax (benefit) at statutory rates	$ 59,139	$ 46,501	$ (4,579)
Amortization of accumulated investment tax credits	(286)	(973)	(1,342)
Flow-through of depreciation items	1,103	1,185	1,465
Earnings attributable to non-controlling interest in Valencia	(5,256)	(5,082)	(5,218)
State income tax, net of federal benefit	4,926	3,921	(2,162)
Impairment of state net operating loss carryforwards	627	(213)	3,619
Allowance for equity funds used during construction	(3,032)	(1,457)	(3,650)
Reversal of deferred items related to BART at SJGS	—	—	1,826
Regulatory recovery of prior year impairment of state net operating loss carryforward, net of amortization	(2,225)	(1,877)	—
Federal income tax rate change	29,606	—	—
Allocation of excess tax benefit related to stock compensation awards	(1,708)	—	—
Other	(1,339)	(1,083)	(2,717)
Total income taxes (benefit)	$ 81,555	$ 40,922	$ (12,758)
Effective tax rate	48.27%	30.80%	97.52%

The components of PNM's net accumulated deferred income tax liability were:

	December 31,	
	2017	2016
	(In thousands)	
Deferred tax assets:		
Net operating loss	$ 67,719	$ 117,922
Regulatory liabilities related to income taxes	152,059	60,940
Federal tax credit carryforwards	60,085	59,156
Shutdown of SJGS Units 2 and 3	2,204	53,434
Other	23,801	41,700
Total deferred tax assets	305,868	333,152
Deferred tax liabilities:		
Depreciation and plant related	(544,270)	(891,578)
Investment tax credit	(55,731)	(56,017)
Regulatory assets related to income taxes	(52,392)	(56,577)
Pension	(51,774)	(50,134)
Regulatory asset for shutdown of SJGS Units 2 and 3	(31,887)	—
Other	(18,826)	(27,512)
Total deferred tax liabilities	(754,880)	(1,081,818)
Net accumulated deferred income tax liabilities	$ (449,012)	$ (748,666)

PNM RESOURCES, INC. AND SUBSIDIARIES
PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES
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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2017, 2016 and 2015

The following table reconciles the change in PNM's net accumulated deferred income tax liability to the deferred income tax benefit included in the Consolidated Statement of Earnings:

	Year Ended December 31, 2017
	(In thousands)
Net change in deferred income tax liability per above table	$ (299,654)
Change in tax effects of income tax related regulatory assets and liabilities	(16,332)
Tax effect of mark-to-market adjustments	(4,110)
Tax effect of excess pension liability	(3,421)
Adjustment for uncertain income tax positions	2,614
Reclassification of unrecognized tax benefits	(2,614)
Regulatory recovery of prior year impairment of state net operating loss carryforward, net of amortization	(2,225)
Federal income tax rate change	402,501
Allocation of cumulative effect adjustment for excess tax benefit related to stock compensation awards	7,770
Other	(1,980)
Deferred income taxes	$ 82,549

TNMP

TNMP's income taxes consist of the following components:

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Current federal income tax	$ 2,472	$ 9,445	$ 1,603
Current state income tax	1,765	1,729	1,639
Deferred federal income tax	27,304	12,690	20,904
Deferred state income tax	(29)	(28)	(21)
Total income taxes	$ 31,512	$ 23,836	$ 24,125

TNMP's provision for income taxes differed from the federal income tax computed at the statutory rate for each of the periods shown. The differences are attributable to the following factors:

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Federal income tax at statutory rates	$ 23,475	$ 22,928	$ 23,131
State income tax, net of federal benefit	1,198	1,132	1,065
Federal income tax rate change	7,865	—	—
Allocation of excess tax benefit related to stock compensation awards	(616)	—	—
Other	(410)	(224)	(71)
Total income taxes	$ 31,512	$ 23,836	$ 24,125
Effective tax rate	46.98%	36.39%	36.5%

PNM RESOURCES, INC. AND SUBSIDIARIES
PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARIES
TEXAS-NEW MEXICO POWER COMPANY AND SUBSIDIARIES

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The components of TNMP's net accumulated deferred income tax liability at December 31, were:

	December 31,	
	2017	2016
	(In thousands)	
Deferred tax assets:		
Regulatory liabilities related to income taxes	$ 43,103	$ 3,718
Other	3,762	6,016
Total deferred tax assets	46,865	9,734

Deferred tax liabilities:		
Depreciation and plant related	(135,647)	(201,017)
CTC	(5,670)	(12,715)
Regulatory assets related to income taxes	(9,564)	(9,800)
Loss on reacquired debt	(6,890)	(11,937)
Pension	(4,296)	(7,153)
AMS	(7,707)	(8,928)
Other	(3,506)	(3,969)
Total deferred tax liabilities	(173,280)	(255,519)
Net accumulated deferred income tax liabilities	$ (126,415)	$ (245,785)

The following table reconciles the change in TNMP's net accumulated deferred income tax liability to the deferred income tax benefit included in the Consolidated Statement of Earnings:

	Year Ended December 31, 2017
	(In thousands)
Net change in deferred income tax liability per above table	$ (119,370)
Change in tax effects of income tax related regulatory assets and liabilities	(112)
Federal income tax rate change	146,451
Other	306
Deferred income taxes	$ 27,275

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Other Disclosures

GAAP requires that the Company recognize only the impact of tax positions that, based on their technical merits, are more likely than not to be sustained upon an audit by the taxing authority. A reconciliation of unrecognized tax benefits (expenses) is as follows:

	PNMR	PNM	TNMP
		(In thousands)	
Balance at December 31, 2014	$ 15,031	$ 12,228	$ —
Additions based on tax positions related to 2015	1,214	1,214	—
Additions (reductions) for tax positions of prior years	(9,790)	(9,790)	—
Settlement payments	—	—	—
Balance at December 31, 2015	6,455	3,652	—
Additions based on tax positions related to 2016	242	242	—
Additions (reductions) for tax positions of prior years	55	55	—
Settlement payments	—	—	—
Balance at December 31, 2016	6,752	3,949	—
Additions based on tax positions related to 2017	262	262	—
Additions (reductions) for tax positions of prior years	2,415	2,352	63
Settlement payments	—	—	—
Balance at December 31, 2017	$ 9,429	$ 6,563	$ 63

Included in the balance of unrecognized tax benefits at December 31, 2017 are $8.9 million, $6.1 million, and $0.1 million that, if recognized, would affect the effective tax rate for PNMR, PNM, and TNMP. The Company does not anticipate that any unrecognized tax expenses or unrecognized tax benefits will be reduced or settled in 2018.

In 2016, the Company undertook an analysis of interest income and interest expense applicable to federal income tax matters. The analysis encompassed the impacts of IRS examinations, amended income tax returns, and filings for carrybacks of tax matters to previous taxable years applicable to all years not closed under the IRS rules. As a result of this effort, PNMR received net refunds from the IRS of $6.5 million. Of the refunds, $2.1 million was recorded as a reduction of the net interest receivable and $5.1 million was recorded as interest income, which was partially offset by $0.7 million of interest expense. In addition, PNMR incurred $0.9 million in professional fees related to the analysis. Of the net pre-tax impacts aggregating $3.5 million, $2.6 million is reflected in the PNM segment, $0.3 million in the TNMP segment, and $0.6 million in the Corporate and Other segment.

Estimated interest income related to refunds the Company expects to receive is included in Other income and estimated interest expense and penalties related to potential cash settlements are included in Interest Charges in the Consolidated Statements of Earnings. Interest income (expense) related to income taxes was as follows:

	PNMR	PNM	TNMP
		(In thousands)	
2017	$ —	$ —	$ —
2016	$ 4,398	$ 3,625	$ 345
2015	$ —	$ —	$ —

There was no accumulated accrued interest receivable or payable related to income taxes as of December 31, 2017 and 2016.

The Company files a federal consolidated and several consolidated and separate state income tax returns. The tax years prior to 2013 are closed to examination by either federal or state taxing authorities other than Arizona. The tax years prior to 2012 are closed to examination by Arizona taxing authorities. Other tax years are open to examination by federal and state taxing authorities. At December 31, 2017, the Company has $410.4 million of federal net operating loss carryforwards that expire

beginning in 2030 and $71.8 million of federal tax credit carryforwards that expire beginning in 2023. State net operating losses expire beginning in 2017 and vary from federal due to differences between state and federal tax law.

In 2013, New Mexico House Bill 641 reduced the New Mexico corporate income tax rate from 7.6% to 5.9%. The rate reduction is being phased-in from 2014 to 2018. In accordance with GAAP, PNMR and PNM adjusted accumulated deferred income taxes to reflect the tax rate at which the balances are expected to reverse during the period that includes the date of enactment, which was in the year ended December 31, 2013. At that time, the portion of the adjustment related to PNM's regulated activities was recorded as a reduction in deferred tax liabilities and an increase in a regulatory liability, based on the assumption that PNM will be required to return the benefit to customers over time. PNM's NM 2016 Rate Case (Note 17) reflects that assumption. In addition, the portion of the adjustment that was not related to PNM's regulated activities was recorded as a reduction in deferred tax assets and an increase in income tax expense. Changes in the estimated timing of reversals of deferred tax assets and liabilities resulted in refinements of the impacts of this change in tax rates being recorded periodically until the rate reduction was fully phased-in. Adjustments to deferred income taxes recorded as increases (decreases) in the regulatory liability and income tax expense are as follows:

	PNMR	PNM	TNMP
		(In thousands)	
December 31, 2017:			
Regulatory liability	$ (10,109)	$ (10,109)	$ —
Income tax expense	$ (1,259)	$ (1,179)	$ —
December 31, 2016:			
Regulatory liability	$ (7,132)	$ (7,132)	$ —
Income tax expense	$ 712	$ 804	$ —
December 31, 2015:			
Regulatory liability	$ (1,903)	$ (1,903)	$ —
Income tax expense	$ (674)	$ (470)	$ —

In 2008, fifty percent bonus tax depreciation was enacted as a temporary two-year stimulus measure as part of the Economic Stimulus Act of 2008. Bonus tax depreciation in various forms was continuously extended since that time, including by the Protecting Americans from Tax Hikes Act of 2015. The 2015 act extended and phased-out bonus tax depreciation through 2019. As discussed above the Tax Act eliminated bonus depreciation for utilities effective September 28, 2017. As a result of the net operating loss carryforwards for income tax purposes created by bonus depreciation and reduced future income taxes payable resulting from New Mexico House Bill 641, certain tax carryforwards are not expected to be utilized before their expiration. In accordance with GAAP, PNMR and PNM have impaired the tax carryforwards which were not expected to be utilized prior to their expiration. The impairments, net of federal tax benefit, for 2015 through 2017 are as follows:

	PNMR	PNM	TNMP
		(In thousands)	
December 31, 2017:			
State tax credit carryforwards	$ —	$ —	$ —
State net operating loss carryforwards	$ 819	$ 627	$ —
Charitable contribution carryforwards	$ 909	$ —	$ —
December 31, 2016:			
State tax credit carryforwards	$ —	$ —	$ —
State net operating loss carryforwards	$ (311)	$ (213)	$ —
Charitable contribution carryforwards	$ —	$ —	$ —
December 31, 2015:			
State tax credit carryforwards	$ 3,092	$ —	$ —
State net operating loss carryforwards	$ 5,278	$ 3,619	$ —
Charitable contribution carryforwards	$ 2,042	$ —	$ —

The impairments of unexpired state tax credits, state net operating loss, and charitable contribution carryforwards are reflected as a valuation allowance against deferred tax assets. The reserve balances, after reflecting expiration of carryforwards under applicable tax laws, at December 31, 2017 and 2016 are as follows:

	PNMR	PNM	TNMP
		(In thousands)	
December 31, 2017:			
State tax credit carryforwards	$ 2,487	$ —	$ —
State net operating loss carryforwards	$ 1,131	$ 839	$ —
Charitable contribution carryforwards	$ 952	$ —	$ —
December 31, 2016:			
State tax credit carryforwards	$ 3,986	$ —	$ —
State net operating loss carryforwards	$ 361	$ 248	$ —
Charitable contribution carryforwards	$ 659	$ —	$ —

The NMPRC's order in the NM 2015 Rate Case (Note 17) approved PNM's request to record a regulatory asset, which net of federal income taxes, amounted to $2.1 million, to recover a 2014 impairment of PNM's New Mexico net operating loss carryforward resulting from an extension of the income tax provision for fifty percent bonus depreciation. The regulatory asset is being recovered through rates over two years. The settlement of the NM 2016 Rate Case (Note 17) included $3.3 million, net of federal tax, resulting from impairment of a 2015 New Mexico net operating loss as an addition to the remaining unamortized balance of the regulatory asset from the NM 2015 Rate Case. The total balance will be recovered over three years beginning in 2018. These impacts, net of amortization, are reflected in income tax expense on the Consolidated Statement of Earnings.

(12) Pension and Other Postretirement Benefits

PNMR and its subsidiaries maintain qualified defined benefit pension plans, postretirement benefit plans providing medical and dental benefits, and executive retirement programs (collectively, the "PNM Plans" and "TNMP Plans"). PNMR maintains the legal obligation for the benefits owed to participants under these plans. The periodic costs or income of the PNM Plans and TNMP Plans are included in regulated rates to the extent attributable to regulated operations. PNM and TNMP receive a regulated return on the amounts funded for pension and OPEB plans in excess of the periodic cost or income to the extent included in retail rates (a "prepaid pension asset").

Participants in the PNM Plans include eligible employees and retirees of PNMR and PNM. Participants in the TNMP Plans include eligible employees and retirees of TNMP. The PNM pension plan was frozen at the end of 1997 with regard to new participants, salary levels, and benefits. Through December 31, 2007, additional credited service could be accrued under the PNM pension plan up to a limit determined by age and service. The TNMP pension plan was frozen at December 31, 2005 with regard to new participants, salary levels, and benefits.

GAAP requires a plan sponsor to (a) recognize in its statement of financial position an asset for a plan's overfunded status or a liability for a plan's underfunded status; (b) measure a plan's assets and its obligations that determine its funded status as of the end of the employer's fiscal year; and (c) recognize changes in the funded status of a defined benefit postretirement plan in the year in which the changes occur.

GAAP requires unrecognized prior service costs and unrecognized gains or losses to be recorded in AOCI and subsequently amortized. The amortization of these incurred costs is included as pension and postretirement benefit periodic cost or income in subsequent years. To the extent the amortization of these items will ultimately be recovered or returned through future rates, PNM and TNMP record the costs as a regulatory asset or regulatory liability.

The Company maintains trust funds for the pension and OPEB plans from which benefits are paid to eligible employees and retirees. The Company's funding policy is to make contributions to the trusts, as determined by an independent actuary, that comply with minimum guidelines of the Employee Retirement Income Security Act and the Internal Revenue Code. Information concerning the investments is contained in Note 8. The Company has in place a policy that defines the investment objectives, es

tablishes performance goals of asset managers, and provides procedures for the manner in which investments are to be reviewed. The plans implement investment strategies to achieve the following objectives:

- Implement investment strategies commensurate with the risk that the Corporate Investment Committee deems appropriate to meet the obligations of the pension plans and OPEB plans, minimize the volatility of expense, and account for contingencies
- Transition asset mix over the long-term to a higher proportion of high quality fixed income investments as the plans' funded statuses improve

Management is responsible for the determination of the asset target mix and the expected rate of return. The target asset allocations are determined based on consultations with external investment advisors. The expected long-term rate of return on pension and postretirement plan assets is calculated on the market-related value of assets. GAAP requires that actual gains and losses on pension and OPEB plan assets be recognized in the market-related value of assets equally over a period of not more than five years, which reduces year-to-year volatility. For the PNM Plans and TNMP Plans, the market-related value of assets is equal to the prior year's market-related value of assets adjusted for contributions, benefit payments and investment gains and losses that are within a corridor of plus or minus 4.0% around the expected return on market value. Gains and losses that are outside the corridor are amortized over five years.

Pension Plans

For defined benefit pension plans, including the executive retirement plans, the PBO represents the actuarial present value of all benefits attributed by the pension benefit formula to employee service rendered prior to that date using assumptions regarding future compensation levels. The ABO represents the PBO without considering future compensation levels. Since the pension plans are frozen, the PBO and ABO are equal. The following table presents information about the PBO, fair value of plan assets, and funded status of the plans:

	PNM Plan		TNMP Plan	
	Year Ended December 31,		Year Ended December 31,	
	2017	2016	2017	2016
	(In thousands)			
PBO at beginning of year	$ 621,751	$ 597,900	$ 67,061	$ 64,198

Service cost	—	—	—	—
Interest cost	26,908	30,307	2,887	3,304
Actuarial (gain) loss	26,298	39,463	3,050	4,318
Benefits paid	(50,974)	(45,919)	(4,575)	(4,759)
PBO at end of year	623,983	621,751	68,423	67,061
Fair value of plan assets at beginning of year	543,601	557,923	60,624	62,082
Actual return on plan assets	69,389	31,597	7,450	3,301
Employer contributions	—	—	—	—
Benefits paid	(50,974)	(45,919)	(4,575)	(4,759)
Fair value of plan assets at end of year	562,016	543,601	63,499	60,624
Funded status – asset (liability) for pension benefits	$ (61,967)	$ (78,150)	$ (4,924)	$ (6,437)

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Actuarial (gain) loss results from changes in:

	PNM Plan		TNMP Plan	
	Year Ended December 31,		Year Ended December 31,	
	2017	2016	2017	2016
	(in thousands)			
Discount rates	$ 27,547	$ 41,849	$ 3,528	$ 5,055
Demographic experience	(1,249)	(334)	(517)	(556)
Other assumption and experience	—	(2,052)	39	(181)
	$ 26,298	$ 39,463	$ 3,050	$ 4,318

The following table presents pre-tax information about prior service cost and net actuarial (gain) loss in AOCI as of December 31, 2017.

	PNM Plan		TNMP Plan
	December 31, 2017		December 31, 2017
	Prior service cost	Net actuarial (gain) loss	Net actuarial (gain) loss
	(In thousands)		
Amounts in AOCI not yet recognized in net periodic benefit cost (income) at beginning of year	$ (1,450)	$ 159,149	$ —
Experience (gain) loss	—	(9,288)	(621)
Regulatory asset (liability) adjustment	—	5,387	621
Amortization recognized in net periodic benefit cost (income)	405	(6,722)	—
Amounts in AOCI not yet recognized in net periodic benefit cost (income) at end of year	$ (1,045)	$ 148,526	$ —
Amortization expected to be recognized in 2018	$ (405)	$ 6,653	$ —

The following table presents the components of net periodic benefit cost (income):

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
PNM Plan			
Service cost	$ —	$ —	$ —
Interest cost	26,908	30,307	28,255
Expected return on plan assets	(33,803)	(35,416)	(39,323)
Amortization of net (gain) loss	16,006	13,820	14,820
Amortization of prior service cost	(965)	(965)	(965)
Net periodic benefit cost	$ 8,146	$ 7,746	$ 2,787
TNMP Plan			
Service cost	$ —	$ —	$ —
Interest cost	2,887	3,304	3,043
Expected return on plan assets	(3,779)	(3,943)	(4,420)
Amortization of net (gain) loss	923	700	782
Amortization of prior service cost	—	—	—
Net periodic benefit cost (income)	$ 31	$ 61	$ (595)

The following significant weighted-average assumptions were used to determine the PBO and net periodic benefit cost (income). Should actual experience differ from actuarial assumptions, the PBO and net periodic benefit cost (income) would be affected.

	Year Ended December 31,		
PNM Plan	**2017**	**2016**	**2015**
Discount rate for determining December 31 PBO	4.05%	4.51%	5.29%
Discount rate for determining net periodic benefit cost (income)	4.51%	5.29%	4.48%
Expected return on plan assets	6.40%	6.50%	6.80%
Rate of compensation increase	N/A	N/A	N/A
TNMP Plan			
Discount rate for determining December 31 PBO	4.01%	4.49%	5.39%
Discount rate for determining net periodic benefit cost (income)	4.49%	5.39%	4.39%
Expected return on plan assets	6.40%	6.50%	6.80%
Rate of compensation increase	N/A	N/A	N/A

The assumed discount rate for determining the PBO was determined based on a review of long-term high-grade bonds and management's expectations. The expected long-term rate of return on plan assets reflects the average rate of earnings expected on the funds invested, or to be invested, to provide for the benefits included in the PBO. Factors that are considered include, but are not limited to, historic returns on plan assets, current market information on long-term returns (e.g., long-term bond rates) and current and target asset allocations between asset categories. If all other factors were to remain unchanged, a 1% decrease in the expected long-term rate of return would cause PNM's and TNMP's 2018 net periodic cost to increase $5.3 million and $0.6 million (analogous changes would result from a 1% increase). The actual rate of return for the PNM and TNMP pension plans was 13.4% and 12.8% for the year ended December 31, 2017.

The Company's long-term pension investment strategy is to invest in assets whose interest rate sensitivity is correlated with the pension liability. The Company has chosen to implement this strategy known as Liability Driven Investing ("LDI") by increasing the liability matching investments as the funded status of the pension plans improves. These liability matching investments are currently fixed income securities. Prior to 2018, the pension plans targeted asset allocation was 21% equities, 65% fixed income, and 14% alternative investments. The Company is contemplating modifying the LDI strategy by decreasing the liability matching fixed income investments portfolio from 65% to 50% beginning in 2018. The new asset allocation will be implemented in 2018. Equity investments are primarily in domestic securities that include large, mid, and small capitalization companies. The pension plans have a 6% targeted allocation to equities of companies domiciled primarily in developed countries outside of the United States. This category includes actively managed international and domestic equity securities that are benchmarked against a variety of style indices. Fixed income investments are primarily corporate bonds of companies from diversified industries and government securities. Alternative investments include investments in hedge funds, real estate funds, and private equity funds. The hedge funds and private equity funds are structured as multi-manager multi-strategy fund of funds to achieve a diversified position in these asset classes. The hedge funds pursue various absolute return strategies such as relative value, long-short equity, and event driven. Private equity fund strategies include mezzanine financing, buy-outs, and venture capital. The real estate investment is structured as an open-ended, commingled private real estate portfolio that invests in a diversified portfolio of assets including commercial property and multi-family housing. See Note 8 for fair value information concerning assets held by the pension plans.

The following pension benefit payments are expected to be paid:

	PNM Plan	TNMP Plan
	(In thousands)	
2018	$ 49,221	$ 5,929
2019	48,639	5,215
2020	47,069	5,108
2021	45,246	5,373
2022	44,232	4,856
2023 - 2027	201,389	22,085

The Company does not expect to make any cash contributions to the pension plans in 2018-2021, but expects to contribute $5.1 million and zero to the PNM and TNMP pension plans in 2022, based on current law, including recent amendments to funding requirements, and estimates of portfolio performance. These anticipations were developed using current funding assumptions with discount rates of 4.0% to 5.1%. Actual amounts to be funded in the future will be dependent on the actuarial assumptions at that time, including the appropriate discount rate. PNM and TNMP may make additional contributions at their discretion.

Other Postretirement Benefit Plans

For postretirement benefit plans, the APBO is the actuarial present value of all future benefits attributed under the terms of the postretirement benefit plan to employee service rendered to date.

The following table presents information about the APBO, the fair value of plan assets, and the funded status of the plans:

PNM Plan	TNMP Plan
Year Ended December 31,	Year Ended December 31,

	2017	2016	2017	2016
	(In thousands)			
APBO at beginning of year	$ 94,269	$ 84,674	$ 12,830	$ 13,106
Service cost	96	140	143	186
Interest cost	4,025	4,346	556	677
Participant contributions	3,069	2,690	379	520
Actuarial (gain) loss	(1,601)	17,877	(381)	(96)
Benefits paid	(9,961)	(11,734)	(1,248)	(1,563)
Plan design changes	—	(3,724)	—	—
APBO at end of year	89,897	94,269	12,279	12,830
Fair value of plan assets at beginning of year	72,694	72,952	8,544	9,111
Actual return on plan assets	14,222	5,923	1,642	476
Employer contributions	332	2,863	685	—
Participant contributions	3,069	2,690	379	520
Benefits paid	(9,961)	(11,734)	(1,248)	(1,563)
Fair value of plan assets at end of year	80,356	72,694	10,002	8,544
Funded status – asset (liability)	$ (9,541)	$ (21,575)	$ (2,277)	$ (4,286)

Actuarial (gain) loss results from changes in:

	PNM Plan		TNMP Plan	
	Year Ended December 31,		Year Ended December 31,	
	2017	2016	2017	2016
	(in thousands)			
Discount rates	$ 3,536	$ 6,569	$ 613	$ 1,112
Claims, contributions, and demographic experience	(5,845)	19,562	(994)	(102)
Assumed participation rate	—	(6,335)	—	(1,013)
Mortality rate	—	(691)	—	(93)
Medical benefits	1,425	(1,228)	—	—
Dental trend assumption	(717)	—	—	—
	$ (1,601)	$ 17,877	$ (381)	$ (96)

In the year ended December 31, 2017, actuarial gains of $10.6 million were recorded as adjustments to regulatory assets for the PNM Plan. For the TNMP Plan, actuarial gains of $1.6 million were recorded as adjustments to regulatory liabilities.

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The following table presents the components of net periodic benefit cost:

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
PNM Plan			
Service cost	$ 96	$ 140	$ 204
Interest cost	4,025	4,346	4,089
Expected return on plan assets	(5,230)	(5,483)	(5,610)
Amortization of net (gain) loss	3,682	1,145	1,966
Amortization of prior service credit	(1,663)	(30)	(642)
Net periodic benefit cost	$ 910	$ 118	$ 7
TNMP Plan			
Service cost	$ 143	$ 186	$ 247
Interest cost	556	677	608
Expected return on plan assets	(456)	(490)	(520)
Amortization of net (gain) loss	(79)	(40)	—
Amortization of prior service cost	—	—	—
Net periodic benefit cost	$ 164	$ 333	$ 335

The following significant weighted-average assumptions were used to determine the APBO and net periodic benefit cost. Should actual experience differ from actuarial assumptions, the APBO and net periodic benefit cost would be affected.

	Year Ended December 31,

PNM Plan	2017	2016	2015
Discount rate for determining December 31 APBO	4.00%	4.47%	5.34%
Discount rate for determining net periodic benefit cost	4.47%	5.34%	4.45%
Expected return on plan assets	7.50%	7.70%	7.70%
Rate of compensation increase	N/A	N/A	N/A
TNMP Plan			
Discount rate for determining December 31 APBO	4.00%	4.47%	5.34%
Discount rate for determining net periodic benefit cost	4.47%	5.34%	4.45%
Expected return on plan assets	5.40%	5.70%	5.70%
Rate of compensation increase	N/A	N/A	N/A

The assumed discount rate for determining the APBO was determined based on a review of long-term high-grade bonds and management's expectations. The expected long-term rate of return on plan assets reflects the average rate of earnings expected on the funds invested, or to be invested, to provide for the benefits included in the APBO. Factors that are considered include, but are not limited to, historic returns on plan assets, current market information on long-term returns (e.g., long-term bond rates), and current and target asset allocations between asset categories. If all other factors were to remain unchanged, a 1% decrease in the expected long-term rate of return would cause PNM's and TNMP's 2018 postretirement benefit cost to increase $0.7 million and $0.1 million (analogous changes would result from a 1% increase). The actual rate of return for the PNM and TNMP postretirement benefit plans was 20.5% and 19.4% for the year ended December 31, 2017.

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The following table shows the assumed health care cost trend rates for the PNM postretirement benefit plan:

	PNM Plan	
	December 31,	
	2017	2016
Health care cost trend rate assumed for next year	6.5%	6.8%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2024	2024

The following table shows the impact of a one-percentage-point change in assumed health care cost trend rates:

	PNM Plan	
	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In thousands)	
Effect on total of service and interest cost	$ 72	$ (111)
Effect on APBO	$ 1,452	$ (2,235)

TNMP's exposure to cost increases in the OPEB plan is minimized by a provision that limits TNMP's share of costs under the plan. Costs of the plan in excess of the limit are wholly borne by the participants. TNMP reached the cost limit at the end of 2001. As a result, a one-percentage-point change in assumed health care cost trend rates would have no effect on either the net periodic expense or the year-end APBO.

The Company's OPEB plans invest in a portfolio that is diversified by asset class and style strategies. The OPEB plans generally use the same pension fixed income and equity investment managers and utilize the same overall investment strategy as described above for the pension plans, except there is no allocation to alternative investments. The other postretirement benefit plans have a target asset allocation of 70% equities and 30% fixed income. See Note 8 for fair value information concerning assets held by the other postretirement benefit plans.

The following other postretirement benefit payments, which reflect expected future service and are net of participant contributions, are expected to be paid:

	PNM Plan	TNMP Plan
	(In thousands)	
2018	$ 7,829	$ 708
2019	7,730	725
2020	7,605	748
2021	7,442	774
2022	7,132	795
2023 - 2027	31,250	4,126

PNM expects to make no contributions to the PNM OPEB plan for 2018-2022. TNMP expects to make contributions to the TNMP OPEB totaling $0.3 million in 2018 and $1.4 million for 2019-2022.

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Executive Retirement Programs

For the executive retirement programs, the following table presents information about the PBO and funded status of the plans:

	PNM Plan		TNMP Plan	
	Year Ended December 31,		Year Ended December 31,	
	2017	2016	2017	2016
	(In thousands)			
PBO at beginning of year	$ 16,212	$ 16,105	$ 787	$ 794
Service cost	—	—	—	—
Interest cost	697	812	33	40
Actuarial (gain) loss	674	768	44	47
Benefits paid	(1,466)	(1,473)	(93)	(94)
PBO at end of year – funded status	16,117	16,212	771	787
Less current liability	1,501	1,510	93	93
Non-current liability	$ 14,616	$ 14,702	$ 678	$ 694

The following table presents pre-tax information about net actuarial loss in AOCI as of December 31, 2017.

	December 31, 2017	
	PNM Plan	TNMP Plan
	(In thousands)	
Amount in AOCI not yet recognized in net periodic benefit cost at beginning of year	$ 2,299	$ —
Experience (gain) loss	674	44
Regulatory asset (liability) adjustment	(391)	(44)
Amortization recognized in net periodic benefit cost (income)	(132)	—
Amount in AOCI not yet recognized in net periodic benefit cost at end of year	$ 2,450	$ —
Amortization expected to be recognized in 2018	$ 151	$ —

The following table presents the components of net periodic benefit cost:

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
PNM Plan			
Service cost	$ —	$ —	$ —
Interest cost	697	812	760
Amortization of net (gain) loss	313	256	325
Amortization of prior service cost	—	—	—
Net periodic benefit cost	$ 1,010	$ 1,068	$ 1,085
TNMP Plan			
Service cost	$ —	$ —	$ —
Interest cost	33	40	36
Amortization of net (gain) loss	9	2	5
Amortization of prior service cost	—	—	—
Net periodic benefit cost	$ 42	$ 42	$ 41

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The following significant weighted-average assumptions were used to determine the PBO and net periodic benefit cost. Should actual experience differ from actuarial assumptions, the PBO and net periodic benefit cost would be affected.

	Year Ended December 31,		
PNM Plan	2017	2016	2015
Discount rate for determining December 31 PBO	4.05%	4.51%	5.29%
Discount rate for determining net periodic benefit cost	4.51%	5.29%	4.48%
Long-term rate of return on plan assets	N/A	N/A	N/A
Rate of compensation increase	N/A	N/A	N/A
TNMP Plan			

Discount rate for determining December 31 PBO	4.01%	4.49%	5.39%
Discount rate for determining net periodic benefit cost	4.49%	5.39%	4.39%
Long-term rate of return on plan assets	N/A	N/A	N/A
Rate of compensation increase	N/A	N/A	N/A

The assumed discount rate for determining the PBO was determined based on a review of long-term high-grade bonds and management's expectations. The impacts of changes in assumptions or experience were not significant.

The following executive retirement plan payments, which reflect expected future service, are expected:

	PNM Plan	TNMP Plan
	(In thousands)	
2018	$ 1,501	$ 93
2019	1,473	91
2020	1,441	89
2021	1,405	85
2022	1,363	81
2023 - 2027	6,014	324

Other Retirement Plans

PNMR sponsors a 401(k) defined contribution plan for eligible employees, including those of its subsidiaries. PNMR's contributions to the 401(k) plan consist of a discretionary matching contribution equal to 75% of the first 6% of eligible compensation contributed by the employee on a before-tax basis. PNMR also makes a non-matching contribution ranging from 3% to 10% of eligible compensation based on the eligible employee's age.

PNMR also provides executive deferred compensation benefits through an unfunded, non-qualified plan. The purpose of this plan is to permit certain key employees of PNMR who participate in the 401(k) defined contribution plan to defer compensation and receive credits without reference to the certain limitations on contributions.

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A summary of expenses for these other retirement plans is as follows:

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
PNMR			
401(k) plan	$ 16,452	$ 17,762	$ 16,725
Non-qualified plan	$ 3,702	$ 2,017	$ 1,436
PNM			
401(k) plan	$ 12,120	$ 13,397	$ 12,679
Non-qualified plan	$ 2,834	$ 1,535	$ 1,090
TNMP			
401(k) plan	$ 4,332	$ 4,365	$ 4,046
Non-qualified plan	$ 868	$ 482	$ 346

(13) Stock-Based Compensation

PNMR has various stock-based compensation programs, including stock options, restricted stock, and performance shares granted under the Performance Equity Plan ("PEP"). Although certain PNM and TNMP employees participate in the PNMR plans, PNM and TNMP do not have separate employee stock-based compensation plans. In 2011, the Company changed its approach to awarding stock-based compensation. As a result, no stock options have been granted since 2010 and awards of restricted stock have increased. Certain restricted stock awards are subject to achieving performance or market targets. Other awards of restricted stock are only subject to time vesting requirements.

Performance Equity Plan

The PEP provides for the granting of non-qualified stock options, restricted stock rights, performance shares, performance units, and stock appreciation rights to officers, key employees, and non-employee members of the Board. Restricted stock under the PEP refers to awards of stock subject to vesting, performance, or market conditions rather than to shares with contractual post-vesting restrictions. Generally, the awards vest ratably over three years from the grant date of the award. However, awards with performance or market conditions vest upon satisfaction of those conditions. In addition, plan provisions provide that upon retirement, participants become 100% vested in certain stock awards. Beginning with 2017 awards, the vesting period for awards of restricted stock to non-employee members of the Board is one year. The total number of shares of PNMR common stock subject to all awards under the PEP, as approved by PNMR's shareholders in May 2014, may not exceed 13.5 million shares, subject to adjustment and certain share counting rules set forth in the PEP. This current share pool is charged five shares for each share subject to restricted stock or other full value award. Re-pricing of stock options is prohibited unless specific shareholder approval is obtained.

Source of Shares

The source of shares for exercised stock options and vested restricted stock is shares acquired on the open market by an independent agent, rather than newly issued shares.

Accounting for Stock Awards

The stock-based compensation expense related to restricted stock awards without performance or market conditions to participants that are retirement eligible on the grant date is recognized immediately at the grant date and is not amortized. Compensation expense for other such awards is amortized to compensation expense over the shorter of the requisite vesting period or the period until the participant becomes retirement eligible. Compensation expense for performance-based shares is recognized ratably over the performance period and is adjusted periodically to reflect the level of achievement expected to be attained. Compensation expense related to market-based shares is recognized ratably over the measurement period, regardless of the actual level of achievement, provided the employees meet their service requirements.

Total compensation expense for stock-based payment arrangements recognized by PNMR for the years ended December 31, 2017, 2016, and 2015 was $6.2 million, $5.6 million, and $4.9 million. Stock compensation expense of $4.4 million, $4.2 million,

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and $3.6 million was charged to PNM and $1.8 million, $1.5 million, and $1.3 million was charged to TNMP. At December 31, 2017, PNMR had unrecognized compensation expense related to stock awards of $3.8 million, which is expected to be recognized over an average of 1.53 years.

PNMR receives a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the price at which the options are sold over the exercise prices of the options, and a tax deduction for the value of restricted stock at the vesting date.

The FASB issued *Accounting Standards Update 2016-09 – Compensation –- Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* to simplify several aspects of the accounting for share-based payment transactions and eliminate diversity in practice. PNMR's historical accounting for stock compensation complies with ASU 2016-09, except for the treatment of the income tax consequences of awards and the presentation of reductions to taxes payable on the Consolidated Statements of Cash Flows. Prior to ASU 2016-09, benefits resulting from income tax deductions in excess of compensation cost recognized under GAAP for vested restricted stock and on exercised stock options (collectively, "excess tax benefits") were recorded to equity provided the excess tax benefits reduced income taxes payable. Deficiencies resulting from tax deductions related to stock awards that were below recognized compensation cost upon vesting and on canceled stock options were recorded to equity. PNMR had not recorded excess tax benefits to equity since 2009 because it is in a net operating loss position for income tax purposes. ASU 2016-09 requires that all excess tax benefits and deficiencies be recorded to tax expense and classified as cash flows from operating activities. PNMR adopted ASU 2016-09 as of January 1, 2017 and recorded excess tax benefits of $2.3 million in the year ended December 31, 2017 of which $1.7 million was allocated to PNM and $0.6 million was allocated to TNMP. As required by ASU 2016-09, PNMR recorded the excess tax benefits that were not recognized in prior years, due to its net operating loss position, as a cumulative effect adjustment of $10.4 million on January 1, 2017, increasing retained earnings and decreasing accumulated deferred income taxes on the Consolidated Balance Sheets. When excess tax benefits are used to reduce income taxes payable, the benefit will be reflected in cash flows from operating activities.

The grant date fair value for restricted stock and stock awards with Company internal performance targets is determined based on the market price of PNMR common stock on the date of the agreements reduced by the present value of future dividends, which will not be received prior to vesting, applied to the total number of shares that are anticipated to vest, although the number of performance shares that ultimately vest cannot be determined until after the performance periods end. The grant date fair value of stock awards with market targets is determined using Monte Carlo simulation models, which provide grant date fair values that include an expectation of the number of shares to vest at the end of the measurement period.

The following table summarizes the weighted-average assumptions used to determine the awards grant date fair value:

	Year Ended December 31,		
Restricted Shares and Performance-Based Shares	**2017**	**2016**	**2015**
Expected quarterly dividends per share	$ 0.2425	$ 0.2200	$ 0.2000
Risk-free interest rate	1.50%	0.94%	0.92%
Market-Based Shares			
Dividend yield	2.67%	2.74%	2.87%
Expected volatility	20.80%	20.44%	18.73%
Risk-free interest rate	1.54%	0.97%	1.00%

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The following table summarizes activity in restricted stock awards, including performance-based and market-based shares, and stock options:

	Restricted Stock		Stock Options	
	Shares	**Weighted-Average Grant Date Fair Value**	**Shares**	**Weighted Average Exercise Price**
Outstanding at December 31, 2016	218,316	$ 27.59	305,874	$ 12.29
Granted	248,271	$ 23.06	—	$ —
Exercised	(273,530)	$ 21.01	(109,433)	$ 15.89
Forfeited	(4,012)	$ 29.96	—	$ —
Expired	—	$ —	(3,000)	$ 30.50

Outstanding at December 31, 2017	189,045	$	31.11	193,441	$	9.98

PNMR's stock-based compensation program provides for performance and market targets through 2018. Included as granted and as exercised in the above table are 49,682 previously awarded shares that were earned for the 2014 through 2016 performance measurement period and ratified by the Board in February 2017 (based upon achieving market targets at "target" levels, weighted at 60%, and not meeting performance targets, weighted at 40%). Excluded from the above table are 97,697 previously awarded shares that were earned for the 2015 through 2017 performance measurement period and ratified by the Board in February 2018 (based upon achieving market targets at above "target" levels, weighted at 40%, and performance targets at below "target" levels, weighted at 60%), as well as maximums of 137,036 and 133,632 shares for the three-year performance periods ending in 2018 and 2019 that would be awarded if all performance and market criteria are achieved at maximum levels and all executives remain eligible.

In March 2012, the Company entered into a retention award agreement with its Chairman, President, and Chief Executive Officer under which she was to receive 135,000 shares of PNMR's common stock if PNMR met specific market targets at the end of 2016 and she remained an employee of the Company. Under the agreement, she received 35,000 of the total shares in 2015 since PNMR achieved the specified market targets at the end of 2014. The specified market target was achieved at the end of 2016 and the Board ratified her receiving the remaining 100,000 shares, which are included in the above table, in February 2017. The retention award was made under the PEP and was approved by the Board on February 28, 2012.

Effective as of January 1, 2015, the Company entered into a retention award agreement with its Executive Vice President and Chief Financial Officer under which he would receive awards of restricted stock if PNMR meets specified performance targets at the end of 2016 and 2017 and he remains an employee of the Company. If PNMR achieved the specific performance target for the period from January 1, 2015 through December 31, 2016, he was to receive $100,000 of PNMR common stock based on the market value per share on the grant date in early 2017. The specified performance target was achieved at the end of 2016 and the Board ratified him receiving $100,000 of PNMR common stock in February 2017 based on a market per share value of $36.30 on the grant date of March 3, 2017, or 2,754 shares, which are included in the above table. Similarly, if PNMR achieved the specified performance target for the period from January 1, 2015 through December 31, 2017, he was to receive $275,000 of PNMR common stock based on the market value per share on the grant date in early 2018. The specified performance target was achieved at the end of 2017 and the Board ratified him receiving $275,000 of PNMR common stock in February 2018 based on the market value per share on the grant date in early March 2018. The above table does not include the restricted stock shares granted in 2018. The retention award was made under the PEP and was approved by the Board on December 9, 2014.

In March 2015, the Company entered into an additional retention award agreement with its Chairman, President, and Chief Executive Officer under which she would receive 53,859 shares of PNMR's common stock if PNMR meets certain performance targets at the end of 2019 and she remains an employee of the Company. Under the agreement, she would receive 17,953 of the total shares if PNMR achieves specified performance targets at the end of 2017. The specified performance target was achieved at the end of 2017 and the Board ratified her receiving the 17,953 shares in February 2018. The above table does not include any restricted stock shares under this retention award agreement. The retention award was made under the PEP and was approved by the Board on February 26, 2015.

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At December 31, 2017, the aggregate intrinsic value of stock options outstanding, all of which are exercisable, was $5.9 million with a weighted-average remaining contract life of 1.55 years. At December 31, 2017, no outstanding stock options had an exercise price greater than the closing price of PNMR common stock on that date.

The following table provides additional information concerning restricted stock activity, including performance-based and market-based shares, and stock options:

	Year Ended December 31,		
Restricted Stock	**2017**	**2016**	**2015**
Weighted-average grant date fair value	$ 23.06	$ 26.49	$ 20.34
Total fair value of restricted shares that vested (in thousands)	$ 5,747	$ 5,079	$ 6,507
Stock Options			
Weighted-average grant date fair value of options granted	$ —	$ —	$ —
Total fair value of options that vested (in thousands)	$ —	$ —	$ —
Total intrinsic value of options exercised (in thousands)	$ 2,234	$ 1,242	$ 2,350

(14) Construction Program and Jointly-Owned Electric Generating Plants

PNM is a participant in several jointly-owned power plant projects. The primary operating or participation agreements for the joint projects expire in July 2022 for SJGS, July 2041 for Four Corners, December 2046 for Luna, and November 2047 for PVNGS.

PNM's expenditures for additions to utility plant were $309.1 million in 2017, including expenditures on jointly-owned projects. TNMP does not participate in the ownership or operation of any generating plants, but incurred expenditures for additions to utility plant of $145.5 million during 2017. On a consolidated basis, PNMR's expenditures for additions to utility plant were $500.5 million in 2017.

Joint Projects

Under the agreements for the jointly-owned projects, PNM has an undivided interest in each asset and liability of the project and records its pro-rata share of each item in the corresponding asset and liability account on PNM's Consolidated Balance Sheets. Likewise, PNM records its pro-rata share of each item of operating and maintenance expenses for its jointly-owned plants within the corresponding operating expense account in its Consolidated Statements of Earnings. PNM is responsible for financing its share of the capital and operating costs of the joint projects.

At December 31, 2017, PNM's interests and investments in jointly-owned generating facilities are:

Station (Fuel Type)	**Plant in Service**	**Accumulated Depreciation[1]**	**Construction Work in Progress**	**Composite Interest**
	(In thousands)			

SJGS (Coal) [2]	$ 920,950	$ (522,750)	$ 8,512	46.30%
PVNGS (Nuclear) [3]	$ 918,830	$ (353,054)	$ 35,038	10.20%
Four Corners Units 4 and 5 (Coal)	$ 204,432	$ (100,914)	$ 61,755	13.00%
Luna (Gas)	$ 70,995	$ (27,023)	$ (13)	33.33%

(1) Includes cost of removal.

(2) See Note 16 for a discussion of the December 2017 shutdown of SJGS Units 2 and 3 and the restructuring of the ownership of SJGS Unit 4.

(3) Includes interest in PVNGS Unit 3, interest in common facilities for all PVNGS units, and owned interests in PVNGS Units 1 and 2, including improvements.

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San Juan Generating Station

PNM operates and jointly owns SJGS. Effective January 1, 2018, SJGS Unit 1 is owned 50% by PNM and 50% by Tucson and SJGS Unit 4 is owned 77.297% by PNM, including a 12.8% interest held as merchant plant, 8.475% by Farmington, 7.2% by Los Alamos, and 7.028% by UAMPS. See Note 16 for additional information about SJGS, including the shutdown of SJGS Units 2 and 3 in December 2017 and the restructuring of SJGS ownership.

Palo Verde Nuclear Generating Station

PNM is a participant in the three units of PVNGS, also known as the Arizona Nuclear Power Project, with APS (the operating agent), SRP, EPE, SCE, SCPPA, and The Department of Water and Power of the City of Los Angeles. PNM has a 10.2% undivided interest in PVNGS, with portions of its interests in Units 1 and 2 held under leases. See Note 7 for additional information concerning the PVNGS leases, including PNM's purchase of the assets underlying certain of the leases at the expiration of the leases on January 15, 2016, and Note 17 for the NMPRC's treatment of those purchases in the ratemaking process.

Operation of each of the three PVNGS units requires an operating license from the NRC. The NRC issued full power operating licenses for Unit 1 in June 1985, Unit 2 in April 1986, and Unit 3 in November 1987. The full power operating licenses were originally for a period of 40 years and authorize APS, as operating agent for PVNGS, to operate the three PVNGS units. In April 2011, the NRC approved extensions in the operating licenses for the plants for 20 years through June 2045 for Unit 1, April 2046 for Unit 2, and November 2047 for Unit 3. In April 2010, APS entered into a Municipal Effluent Purchase and Sale Agreement that provides effluent water rights necessary for cooling purposes at PVNGS through 2050.

Four Corners Power Plant

PNM is a participant in two units of Four Corners with APS (the operating agent), an affiliate of APS, SRP, and Tucson. PNM has a 13.0% undivided interest in Units 4 and 5 of Four Corners. The Four Corners plant site is leased from the Navajo Nation and is also subject to an easement from the federal government. APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. See Note 16 for additional information about Four Corners.

Luna Energy Facility

Luna is a combined-cycle power plant near Deming, New Mexico. Luna is owned equally by PNM, Tucson, and Samchully Power & Utilities 1, LLC. The operation and maintenance of the facility has been contracted to North American Energy Services.

Construction Program

The Company anticipates making substantial capital expenditures for the construction and acquisition of utility plant and other property and equipment. An unaudited summary of the budgeted construction expenditures, including expenditures for jointly-owned projects, and nuclear fuel, is as follows:

	2018	2019	2020	2021	2022	Total
	(In millions)					
PNM	$ 295.0	$ 339.0	$ 313.4	$ 315.8	$ 493.7	$ 1,756.9
TNMP	185.8	170.5	170.0	170.5	170.1	866.9
Corporate and Other	19.4	17.3	17.0	17.5	17.1	88.3
Total PNMR	$ 500.2	$ 526.8	$ 500.4	$ 503.8	$ 680.9	$ 2,712.1

The construction expenditure estimates are under continuing review and subject to ongoing adjustment, as well as to Board review and approval. The above construction expenditures include $7.9 million for environmental upgrades at Four Corners, $72.8 million for 50 MW of new solar facilities included in PNM's 2018 renewable energy procurement plan, approximately $170.0 million for an anticipated expansion of PNM's transmission system, and approximately $100.0 million in 2021 and $300.0 million in 2022 for the costs of replacement resources related to the potential shutdown of SJGS Units 1 and 4 in 2022. See Note 17. Expenditures for the expansion of PNM's transmission system and SJGS replacement sources are subject to obtaining necessary approvals of the NMPRC. PNM will be required to file CCN applications with the NMPRC to obtain those approvals.

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(15) Asset Retirement Obligations

AROs are recorded based on studies to estimate the amount and timing of future ARO expenditures and reflect underlying assumptions, such as discount rates, estimates of the

future costs for decommissioning, and the timing of the removal activities to be performed. Approximately 80% of PNM's total ARO liabilities is related to nuclear decommissioning of PVNGS. PNM is responsible for all decommissioning obligations related to its entire interest in PVNGS, including portions under lease both during and after termination of the leases. Studies of the decommissioning costs of PVNGS, as well as SJGS and Four Corners are performed periodically and revisions to the ARO liabilities are recorded. Changes in the assumptions underlying the calculations may also require revisions to the estimated AROs when identified. A reconciliation of the ARO liabilities is as follows:

	PNMR	PNM	TNMP
		(In thousands)	
Liability at December 31, 2014	$ 104,170	$ 103,182	$ 848
Liabilities incurred	—	—	—
Liabilities settled	(730)	(506)	(224)
Accretion expense	8,625	8,543	71
Revisions to estimated cash flows	(170)	(170)	—
Liability at December 31, 2015	111,895	111,049	695
Liabilities incurred	—	—	—
Liabilities settled	(14)	(14)	—
Accretion expense	9,170	9,098	59
Revisions to estimated cash flows	6,468	6,468	—
Liability at December 31, 2016	127,519	126,601	754
Liabilities incurred[(1)]	1,854	1,853	—
Liabilities settled	(968)	(944)	(24)
Accretion expense	10,680	10,603	63
Revisions to estimated cash flows	7,594	7,594	—
Liability at December 31, 2017	$ 146,679	$ 145,707	$ 793

[(1)] Represents the obligation related to the additional ownership interest in SJGS Unit 4 that PNM acquired on December 31, 2017 due to the restructuring of the ownership of SJGS.

(16) Commitments and Contingencies

Overview

There are various claims and lawsuits pending against the Company. The Company also is subject to federal, state, and local environmental laws and regulations and periodically participates in the investigation and remediation of various sites. In addition, the Company periodically enters into financial commitments in connection with its business operations. Also, the Company is involved in various legal and regulatory (Note 17) proceedings in the normal course of its business. It is not possible at this time for the Company to determine fully the effect of all litigation and other legal and regulatory proceedings on its financial position, results of operations, or cash flows.

With respect to some of the items listed below, the Company has determined that a loss is not probable or that, to the extent probable, cannot be reasonably estimated. In some cases, the Company is not able to predict with any degree of certainty the range of possible loss that could be incurred. Nevertheless, the Company assesses legal and regulatory matters based on current information and makes judgments concerning their potential outcome, giving due consideration to the nature of the claim, the amount and nature of any damages sought, and the probability of success. Such judgments are made with the understanding that the outcome of any litigation, investigation, or other legal proceeding is inherently uncertain. In accordance with GAAP, the Company records liabilities for matters where it is probable a loss has been incurred and the amount of loss is reasonably estimable. The actual outcomes of the items listed below could ultimately differ from the judgments made and the differences could be material. The Company cannot make any assurances that the amount of reserves or potential insurance coverage will be sufficient

to cover the cash obligations that might be incurred as a result of litigation or regulatory proceedings. Except as otherwise disclosed, the Company does not expect that any known lawsuits, environmental costs, and commitments will have a material effect on its financial condition, results of operations, or cash flows.

Commitments and Contingencies Related to the Environment

PVNGS Decommissioning Funding

The costs of decommissioning a nuclear power plant are substantial. PNM is responsible for all decommissioning obligations related to its entire interest in PVNGS, including portions under lease both during and after termination of the leases. PNM has a program for funding its share of decommissioning costs for PVNGS, including portions held under leases. The nuclear decommissioning funding program is invested in equities and fixed income instruments in qualified and non-qualified trusts. PNM funded $2.0 million, $4.2 million, and $4.9 million for the years ended December 31, 2017, 2016, and 2015 into the qualified and non-qualified trust funds. The market value of the trusts at December 31, 2017 and 2016 was $293.7 million and $253.9 million.

Nuclear Spent Fuel and Waste Disposal

Nuclear power plant operators are required to enter into spent fuel disposal contracts with the DOE that require the DOE to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. Although the Nuclear Waste Policy Act required the DOE to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998, the DOE announced that it would not be able to open the repository by 1998 and sought to excuse its performance of these requirements. In November 1997, the DC Circuit issued a decision preventing the DOE from excusing its own delay, but refused to order the DOE to begin accepting spent nuclear fuel. Based on this decision and the DOE's delay, a number of utilities, including APS (on behalf of itself and the other PVNGS owners, including PNM), filed damages actions against the DOE in the Court of Federal Claims. The lawsuits filed by APS alleged that damages were incurred due to DOE's continuing failure to remove spent nuclear fuel and high-level waste from PVNGS. In August 2014, APS and DOE entered into a settlement agreement, which established a process for the payment of claims for costs incurred. Under the settlement agreement, APS must

submit claims annually for payment of allowable costs. In 2015, PNM recorded $5.6 million, including $3.6 million credited back to PNM's customers, for its share of the settlement under this process for costs incurred from July 2011 through June 2015. Thereafter, PNM began recording estimated claims quarterly. The settlement agreement has been extended to December 31, 2019.

PNM estimates that it will incur approximately $57.7 million (in 2016 dollars) for its share of the costs related to the on-site interim storage of spent nuclear fuel at PVNGS during the term of the operating licenses. PNM accrues these costs as a component of fuel expense as the fuel is consumed. At December 31, 2017 and 2016, PNM had a liability for interim storage costs of $12.3 million and $12.1 million included in other deferred credits.

PVNGS has sufficient capacity at its on-site ISFSI to store all of the nuclear fuel that will be irradiated during the initial operating license period, which ends in December 2027. Additionally, PVNGS has sufficient capacity at its on-site ISFSI to store a portion of the fuel that will be irradiated during the period of extended operation, which ends in November 2047. If uncertainties regarding the United States government's obligation to accept and store spent fuel are not favorably resolved, APS will evaluate alternative storage solutions that may obviate the need to expand the ISFSI to accommodate all of the fuel that will be irradiated during the period of extended operation.

On June 8, 2012, the DC Circuit issued its decision on a challenge by several states and environmental groups of the NRC's rulemaking regarding temporary storage and permanent disposal of high level nuclear waste and spent nuclear fuel. The petitioners had challenged the NRC's 2010 update to the agency's Waste Confidence Decision and temporary storage rule (the "Waste Confidence Decision"). The DC Circuit found that the Waste Confidence Decision update constituted a major federal action, which, consistent with NEPA, requires either an environmental impact statement or a finding of no significant impact from the NRC's actions. The DC Circuit found that the NRC's evaluation of the environmental risks from spent nuclear fuel was deficient and, therefore, remanded the Waste Confidence Decision update for further action consistent with NEPA. On September 6, 2012, the NRC commissioners issued a directive to the NRC staff to proceed with development of a generic EIS to support an updated Waste Confidence Decision, which was issued in September 2013. On August 26, 2014, the NRC approved a final rule on the environmental effects of continued storage of spent nuclear fuel. The continued storage rule adopted the findings of the generic EIS regarding the environmental impacts of storing spent fuel at any reactor site after the reactor's licensed period of operations.

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As a result, those generic impacts do not need to be re-analyzed in the environmental reviews for individual licenses. The August 2014 final rule has been subject to continuing legal challenges before the NRC and the United States Court of Appeals. On May 19, 2016, the NRC denied petitions filed by multiple petitioners to revise the August 2014 rule. The DC Circuit issued an order upholding the August 2014 rule on June 3, 2016 and denied a subsequent petition for rehearing on August 8, 2016.

In 2011, the National Association of Regulatory Utility Commissioners and the Nuclear Energy Institute challenged, in the DC Circuit, DOE's 2010 determination of the adequacy of the one tenth of a cent per KWh fee (the "one-mill fee") paid by the nation's commercial nuclear power plant owners pursuant to their individual contracts with the DOE. On January 3, 2014, the DOE notified Congress of its intention to suspend collection of the one-mill fee, subject to Congress' disapproval, as ordered by the DC Circuit. On May 16, 2014, the DOE adjusted the fee to zero. PNM cannot predict if there will be challenges to this action or the potential outcome of such challenges.

The Clean Air Act

Regional Haze

In 1999, EPA developed a regional haze program and regional haze rules under the CAA. The rule directs each of the 50 states to address regional haze. Pursuant to the CAA, states have the primary role to regulate visibility requirements by promulgating SIPs. States are required to establish goals for improving visibility in national parks and wilderness areas (also known as Class I areas) and to develop long-term strategies for reducing emissions of air pollutants that cause visibility impairment in their own states and for preventing degradation in other states. States must establish a series of interim goals to ensure continued progress by adopting a new SIP every ten years. In the first SIP planning period, states were required to conduct BART determinations for certain covered facilities, including utility boilers, built between 1962 and 1977 that have the potential to emit more than 250 tons per year of visibility impairing pollution. If it is demonstrated that the emissions from these sources cause or contribute to visibility impairment in any Class I area, then BART must be installed by 2018. For all future SIP planning period, states must evaluate whether additional emissions reduction measures may be needed to continue making reasonable progress toward natural visibility conditions.

On January 10, 2017, EPA published in the Federal Register revisions to the regional haze rule. EPA also provided a companion draft guidance document for public comment. The new rule delayed the due date for the next cycle of SIPs from 2019 to 2021, altered the planning process that states must employ in determining whether to impose "reasonable progress" emission reduction measures, and gave new authority to federal land managers to seek additional emission reduction measures outside of the states' planning process. Finally, the rule made several procedural changes to the regional haze program, including changes to the schedule and process for states to file 5-year progress reports. EPA's new rule was challenged by numerous parties. On January 19, 2018, EPA filed a motion to hold the case in abeyance in light of several letters issued by EPA on January 17, 2018 to grant various petitions for reconsideration of the 2017 rule revisions. Although EPA's decision to revisit the rule is not a determination on the merits of the issues raised in those petitions, EPA is likely to propose and take comment on additional revisions to the regional haze rules in the near future. PNM is evaluating the potential impacts of this rule.

SJGS

BART Compliance – SJGS is a source that is subject to the statutory obligations of the CAA to reduce visibility impacts. The State of New Mexico submitted its SIP on the regional haze and interstate transport elements of the visibility rules for review by EPA in June 2011. The SIP required SJGS to reduce NOx emissions by installing selective non-catalytic reduction technology ("SNCR") as BART. Nevertheless, in August 2011, EPA published a FIP, which included a regional haze BART determination for SJGS that required installation of selective catalytic reduction technology ("SCR") as BART on all four units by September 21, 2016.

PNM, as the operating agent for SJGS, engaged in discussions with NMED and EPA regarding an alternative to the FIP and SIP, which resulted in a non-binding agreement that included the retirement of SJGS Units 2 and 3 by the end of 2017 and the installation of SNCRs on Units 1 and 4 by the later of January 31, 2016 or 15 months after EPA approval of a revised SIP (the "RSIP"). EPA issued final rules, which became effective on November 10, 2014, approving the RSIP and withdrawing the FIP.

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In addition to the SNCR equipment required by the RSIP, the NSR permit, which was required to be obtained in order to install the SNCRs, specified that SJGS Units 1 and 4 be converted to balanced draft technology ("BDT"). The requirement to install BDT was made binding and enforceable in the NSR permit issued by NMED that accompanied the RSIP submitted to the EPA. EPA's rule approving the RSIP specifically references the NSR permit by including a condition that requires "modification of the fan systems on Units 1 and 4 to achieve 'balanced' draft configuration …."

Following issuance of the FIP, PNM estimated the total cost to install SCRs on all four units of SJGS to be between approximately $824 million and $910 million, including BDT equipment to assist with compliance with the NAAQS requirements and to eliminate fugitive boiler emissions. PNM had previously indicated it estimated the cost of SNCRs on all four units of SJGS to be between approximately $85 million and $90 million based on a conceptual design study. Along with the SNCR installation, additional BDT equipment would be required to be installed, the cost of which had been estimated to total between approximately $105 million and $110 million for all four units of SJGS. Based upon its SJGS ownership interest at that time, PNM's share of the costs described above would have been about 46.3%.

Following the February 2013 development of the alternative BART compliance plan, PNM began taking steps to prepare for the potential installation of SNCR and BDT equipment on Units 1 and 4 and entered into contracts for the work. Installation of SNCRs on Unit 1 and BDT equipment on both Units 1 and 4 was completed in 2015 and installation of SNCRs on Unit 4 was completed in January 2016, which dates were within the timeframe contained in the RSIP. PNM's share of the total costs for SNCRs and BDT equipment was $77.7 million. See Note 17 for information concerning the NMPRC's treatment of BDT in PNM's NM 2015 Rate Case. Although operating costs will be reduced due to the retirement of SJGS Units 2 and 3, the operating costs for SJGS Units 1 and 4 have increased with the installation of SNCR and BDT equipment.

On December 20, 2013, PNM made a filing with the NMPRC requesting certain approvals necessary to effectuate the RSIP. In this filing, PNM requested:

- Permission to retire SJGS Units 2 and 3 at December 31, 2017 and to recover over 20 years their net book value at that date along with a regulated return on those costs
- A CCN to include PNM's ownership of PVNGS Unit 3, amounting to 134 MW, as a resource to serve New Mexico retail customers at a proposed value of $2,500 per KW, effective January 1, 2018
- An order allowing cost recovery for PNM's share of the installation of SNCR and BDT equipment to comply with NAAQS requirements on SJGS Units 1 and 4, not to exceed a total cost of $82 million

PNM's filing also addressed replacement of the capacity from the shutdown of SJGS Units 2 and 3 (which would reduce PNM's ownership in SJGS by 418 MW), a possible increase in PNM's ownership in SJGS Unit 4, the identification of a new natural gas-fired generation source, and 40 MW of new utility-scale solar PV. PNM received approval to construct the 40 MW of solar PV facilities in its 2015 Renewable Energy Plan. See Note 17. PNM's requests in the December 20, 2013 NMPRC filing were based on the status of the negotiations among the SJGS owners at that time regarding ownership restructuring and other matters (see SJGS Ownership Restructuring Matters below). On October 1, 2014, PNM and certain intervenors filed a stipulation with the NMPRC that would have settled all matters in PNM's filing. On April 8, 2015, the Hearing Examiner in the case issued a Certification of Stipulation, which recommended the NMPRC reject the stipulation as proposed. In June 2015, a NMPRC Commissioner issued an order designating a facilitator to determine whether an uncontested settlement among some or all of the parties in this case could be accomplished. On August 13, 2015, as a result of the facilitation process, PNM, the staff of the NMPRC, the NMAG, Western Resource Advocates, and the Coalition for Clean Affordable Energy filed a settlement agreement with the NMPRC. NMIEC, Interwest Energy Alliance, and New Mexico Independent Power Producers subsequently joined in this agreement and NEE filed in opposition to the agreement. The stipulating parties agreed that the October 2014 stipulation should be approved, as modified by the settlement agreement (collectively, the "Stipulated Settlement").

The Hearing Examiner scheduled a hearing on PNM's application concerning BART for SJGS to begin on October 13, 2015. NEE previously filed motions before the NMPRC requesting that four of the five NMPRC commissioners recuse themselves, alleging they had improper ex-parte communications, were biased, and had pre-judged the outcome of the BART case. Each of the four commissioners declined to recuse themselves. On October 5, 2015, NEE filed a Petition for a Writ of Mandamus and Request for Stay in the NM Supreme Court requesting the four commissioners be recused from this case and that PNM's application be dismissed. On October 9, 2015, the NM Supreme Court issued orders that allowed the hearing conducted by the Hearing Examiner to proceed, but ordered that any action by the NMPRC be stayed, pending a decision by the NM Supreme Court on

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NEE's petition. The hearing on the Stipulated Settlement was held from October 13, 2015 through October 20, 2015. Oral argument on NEE's petition was held before the NM Supreme Court on November 9, 2015. On November 9, 2015, the NM Supreme Court denied NEE's petition.

On December 16, 2015, following oral argument, the NMPRC issued an order adopting the Stipulated Settlement. As provided in that order:

- PNM would retire SJGS Units 2 and 3 (PNM's ownership interest was 418 MW) by December 31, 2017 and recover, over 20 years, 50% of their undepreciated net book value at that date and earn a regulated return on those costs
- PNM was granted a CCN to acquire an additional 132 MW in SJGS Unit 4, effective January 1, 2018, with an initial book value of zero, plus the costs of SNCR and other capital additions (an aggregate of $20.7 million)
- PNM was granted a CCN for 134 MW of PVNGS Unit 3 with an initial rate base value equal to the book value as of December 31, 2017, including transmission assets associated with PVNGS Unit 3 (an aggregate of $154.9 million)
- No later than December 31, 2018, and before entering into a binding agreement for post-2022 coal supply for SJGS, PNM will file its position and supporting testimony in a NMPRC case to determine the extent to which SJGS should continue serving PNM's retail customers' needs after mid-2022; all parties to the stipulation agree to support this case being decided within six months (see Other SJGS Matters below and Note 17)
- PNM was authorized to acquire 65 MW of SJGS Unit 4 as merchant plant; PNM and PNMR commit that no further coal-fired merchant plant will be acquired at any time by PNM, PNMR, or any PNM affiliate; PNM is not precluded from seeking a CCN to include the 65 MW or other coal capacity in rate base
- Beginning January 1, 2020, for every MWh produced by 197 MW of coal-fired generation from PNM's ownership share of SJGS, PNM will acquire and retire one MWh of RECs or allowances that include a zero-CO_2 emission attribute compliant with EPA's Clean Power Plan; this REC retirement is in addition to what is required to meet the RPS; the cost of these RECs are to be capped at $7.0 million per year and will be recovered in rates; PNM should purchase EPA-compliant RECs from New Mexico renewable generation unless those RECs are more costly
- PNM would accelerate recovery of SNCR costs on SJGS Units 1 and 4 so that the costs are fully recovered by July 1, 2022 (cost recovery for PNM's BDT project is discussed in Note 17)
- PNM would not recover approximately $20 million of other costs incurred in connection with CAA compliance

- The NMPRC would issue a Notice of Proposed Dismissal in PNM's 2014 IRP

At December 31, 2015, PNM's carrying value for its current ownership share of SJGS Units 2 and 3 included plant in service of $468.2 million, accumulated depreciation and amortization (including cost of removal) of $193.3 million, and construction work in progress of $2.2 million for a net book value of $277.1 million. PNM estimated the undepreciated net book value of SJGS Units 2 and 3 at December 31, 2017 would be approximately $255.3 million, 50% of which would be recovered over a 20-year period, including a return on the unrecovered amount at PNM's WACC. At December 31, 2015, PNM recorded a $127.6 million regulatory disallowance to reflect the write-off of the 50% of the estimated December 31, 2017 net book value that would not be recovered. A regulatory disallowance of $21.6 million was also recorded at December 31, 2015 for other unrecoverable costs based on the approved Stipulated Settlement. The new coal mine reclamation arrangement entered into in conjunction with the new coal supply agreement ("SJGS CSA"), described under Coal Supply below, resulted in a $16.5 million increase in the liability recorded for coal mine reclamation. The expense recorded for this increase and the above disallowances, aggregating $165.7 million, is included in regulatory disallowances and restructuring costs on the Consolidated Statements of Earnings. In addition, the shutdown of SJGS Units 2 and 3 would result in the reversal of certain deferred income tax items. The estimated impact of these tax items resulted in an expense of $1.8 million being recorded at December 31, 2015, which amount is included in income tax expense on the Consolidated Statement of Earnings.

During 2016, PNM revised its estimates of the December 31, 2017 projected book value of SJGS Units 2 and 3 and the other unrecoverable costs, which resulted in a net expense of $3.7 million, consisting of a $0.9 million expense due to a revision of the estimated net book value of SJGS Units 2 and 3, a $4.5 million expense related to a refinement of the estimated liability for coal mine reclamation resulting from the new coal mine reclamation arrangement, and a $1.7 million reduction of the other unrecoverable costs that is reflected in regulatory disallowances and restructuring costs on the Consolidated Statement of Earnings. In addition, PNMR Development recorded an expense of $0.6 million in 2016 for costs it was obligated to reimburse the other SJGS participants under the restructuring arrangement, which is included in other deductions on the Consolidated Statement of Earnings. At December 31, 2016, the carrying value for PNM's current ownership share of SJGS Units 2 and 3 was comprised of plant in service of $471.8 million and accumulated depreciation and amortization (including cost of removal) of $203.9 million

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for a net undepreciated book value of $267.9 million, offset by 50% (which equaled $128.6 million) of the anticipated December 31, 2017 net undepreciated book value of SJGS Units 2 and 3 that will not be recovered, resulting in the net carrying value for SJGS Units 2 and 3 being $139.3 million at December 31, 2016.

SJGS Unit 3 was shut down on December 19, 2017 and SJGS Unit 2 was shut down on December 20, 2017. At shutdown, the carrying value for PNM's ownership share of SJGS Units 2 and 3 was comprised of plant in service of $439.4 million and accumulated depreciation and amortization (including cost of removal) of $188.3 million for a net book value of $251.1 million. As of December 31, 2017, these amounts were written off and offset by previously recorded losses of $128.6 million. PNM also recorded a regulatory asset of $125.5 million for the 50% of the undepreciated book value that is to be recovered from ratepayers pursuant to the December 15, 2015 NMPRC order described above. This resulted in the reversal of previously recorded losses of $3.0 million being recorded at December 31, 2017. In addition, PNM recognized a reversal of $1.0 million of previously recorded losses for other unrecoverable costs. These reversals, which total $4.0 million, are included in regulatory disallowances and restructuring costs on the Consolidated Statements of Earnings.

On January 14, 2016, NEE filed a notice of appeal with the NM Supreme Court of the NMPRC's December 16, 2015 order. On July 22, 2016, NEE filed a brief alleging that the NMPRC's decision violated New Mexico statutes and NMPRC regulations because PNM did not adequately consider replacement resources other than those proposed by PNM, the NMPRC did not require PNM to adequately address and mitigate ratepayer risk, the NMPRC unlawfully shifted the burden of proof, and the NMPRC's decision was arbitrary and capricious. Answer briefs refuting NEE's claims were filed on November 2, 2016 by PNM, the NMPRC, and certain intervenors. Reply briefs were filed by NEE on January 9, 2017 and the parties presented oral argument to the court on January 25, 2017. The court has not rendered a decision on the appeal and there is no required time frame for a decision. In addition, on March 31, 2016, NEE filed a complaint with the NMPRC against PNM regarding the financing provided by NM Capital to facilitate the sale of SJCC (see Coal Supply below). The complaint alleges that PNM failed to comply with its discovery obligation in the SJGS abandonment case and requests the NMPRC investigate whether the financing transactions could adversely affect PNM's ability to provide electric service to its retail customers. PNM responded to the complaint on May 4, 2016. The NMPRC has taken no action on this matter. PNM cannot currently predict the outcome of these matters.

SJGS Ownership Restructuring Matters – Prior to December 31, 2017, SJGS was jointly owned by PNM and eight other entities, including three participants that operate in the State of California. Furthermore, each participant did not have the same ownership interest in each unit. The SJPPA that governs the operation of SJGS expires on July 1, 2022. In connection with requirements to install SNCR and BDT equipment at SJGS, the California participants indicated that, under California law, they might be prohibited from making significant capital improvements to SJGS and expressed the intent to exit their ownership in SJGS by December 31, 2017. One other participant also expressed a similar intent to exit ownership in the plant. As a result, the SJGS participants negotiated a restructuring of the ownership in SJGS and addressed the obligations of the exiting participants for plant decommissioning, mine reclamation, environmental matters, and certain future operating costs, among other items. Prior to the restructuring, the exiting participants owned 50.0% of SJGS Unit 3 and 38.8% of SJGS Unit 4, but none of SJGS Units 1 and 2, and PNM owned 50.0% of SJGS Units 1, 2, and 3 and 38.5% of SJGS Unit 4.

Following mediated negotiations, the SJGS participants executed the San Juan Project Restructuring Agreement ("SJGS RA") on July 31, 2015. The SJGS RA provides the essential terms of restructured ownership and addresses other related matters, including that the exiting participants remain obligated for their proportionate shares of environmental, mine reclamation, and certain other legacy liabilities that are attributable to activities that occurred prior to their exit. PNMR Development became a party to the SJGS RA and agreed to acquire an ownership interest in SJGS Unit 4 on the December 31, 2017 exit date, but had obligations related to Unit 4 before then. Under the SJGS RA, PNM would acquire 132 MW and PNMR Development would acquire 65 MW of the capacity in SJGS Unit 4 from the exiting owners on the exit date for no initial cost other than funding capital improvements, including the costs of installing SNCR and BDT equipment. PNMR Development's share of the costs of installing SNCR and BDT equipment amounted to $7.6 million. Consistent with the NMPRC order, PNM acquired the rights and obligations related to the 65 MW from PNMR Development effective on December 31, 2017 in order to facilitate dispatch of power from that capacity.

The SJGS RA became effective contemporaneously with the effectiveness of the new SJGS CSA. The effectiveness of the new SJGS CSA was dependent on the closing of the purchase of the existing coal mine operation by a new mine operator, which as discussed in Coal Supply below, occurred on January 31, 2016. The SJGS RA sets forth the terms under which PNM acquired the coal inventory of the exiting SJGS participants as of January 1, 2016 and supplied coal to the exiting participants for

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the period from January 1, 2016 through December 31, 2017, which arrangement provided economic benefits that were passed on to PNM's customers through the FPPAC. The SJGS RA also included provisions whereby the exiting owners made payments to certain of the remaining participants, not including PNM, related to the restructuring. PNMR Development's share of the restructuring fee was recorded at December 31, 2015 and the $3.1 million impact is included in other income on the Consolidated Statements of Earnings.

On September 25, 2015, PNM made an application at FERC seeking certain approvals necessary for implementation of the restructured SJGS participation agreements. FERC approved the application on December 30, 2015.

SJGS Units 2 and 3 were shut down in December 2017 and the restructuring of SJGS ownership under the SJGS RA occurred on December 31, 2017, including PNM's acquisition of the additional 132 MW and 65 MW ownership interests in SJGS Unit 4 as set forth above. In accordance with the FERC chart of accounts, plant in service for utility assets acquired is to be recorded at the original cost of the assets less accumulated depreciation. Since PNM did not pay for any costs incurred prior to the effective date of the SJGS RA, PNM increased both plant in service and accumulated depreciation for the original cost of the acquired interests at that date, estimated to be $261.8 million, on December 31, 2017. As ordered by the NMPRC, PNM will treat the 65 MW interest as merchant utility plant that will be excluded from retail rates. In anticipation of the transfer of ownership, PNM entered into agreements to sell the power from 36 MW of that capacity to a third party at a fixed price for the period January 1, 2018 through June 30, 2022 (Note 8). Beginning in 2018, SJGS is jointly owned by five entities. Including the 65 MW considered to be merchant plant, PNM's ownership share is 77.3% in SJGS Unit 4 and an aggregate of 66.3% in SJGS Units 1 and 4.

Other SJGS Matters – The SJPPA requires PNM, as operating agent, to obtain approval of capital improvement project expenditures from participants who have an ownership interest in the relevant unit or property common to more than one unit. The SJPPA also obligates PNM to take reasonable and prudent actions necessary for the successful and proper operation of SJGS if the participants fail to approve the requested expenditures. PNM presented the SNCR project, including BDT equipment, to the SJGS participants in Unit 1 and Unit 4 for approval in October 2013. The project was approved for Unit 1, but the Unit 4 project, which included some of the California participants, was not approved. PNM subsequently submitted several requests to the owners of Unit 4 for approval of certain expenditures critical to comply with the time frame in the RSIP, as well as requests to approve the total forecasted project expenses. The required majority of Unit 4 owners did not approve these requests. PNM, in its capacity as operating agent, subsequently issued several "Prudent Utility Practice" notices under the SJPPA indicating PNM was undertaking certain critical activities to comply with regulatory requirements and keep the Unit 4 SNCR project on schedule.

Although the SJGS RA results in an agreement among the SJGS participants enabling compliance with current CAA requirements, it is possible that the financial impact of climate change regulation or legislation, other environmental regulations, the result of litigation, and other business considerations, could jeopardize the economic viability of SJGS or the ability or willingness of individual participants to continue participation in the plant. PNM's 2017 IRP (Note 17) filed with the NMPRC on July 3, 2017 presented resource portfolio plans for scenarios that assumed SJGS will operate beyond the end of the current coal supply agreement that runs through June 30, 2022 and for scenarios that assumed SJGS will cease operations after mid-2022. The 2017 IRP data shows that retiring SJGS in 2022 would provide long-term cost benefits to PNM's customers.

Four Corners

On August 6, 2012, EPA issued its Four Corners FIP with a final BART determination for Four Corners. The rule included two compliance alternatives. On December 30, 2013, APS notified EPA that the Four Corners participants selected the alternative that required APS to permanently close Units 1, 2, and 3 by January 1, 2014 and install SCR post-combustion NOx controls on each of Units 4 and 5 by July 31, 2018. PNM owns a 13% interest in Units 4 and 5, but had no ownership interest in Units 1, 2, and 3, which were shut down by APS on December 30, 2013. For particulate matter emissions, EPA is requiring Units 4 and 5 to meet an emission limit of 0.015 lbs/MMBTU and the plant to meet a 20% opacity limit, both of which are achievable through operation of the existing baghouses. Although unrelated to BART, the final BART rule also imposes a 20% opacity limitation on certain fugitive dust emissions from Four Corners' coal and material handling operations.

PNM estimates its share of costs for post-combustion controls at Four Corners Units 4 and 5 to be up to $88.9 million, including amounts incurred through December 31, 2017 and PNM's AFUDC. See Note 17 for information on the NMPRC's treatment of these costs in PNM's NM 2016 Rate Case.

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The Four Corners plant site is leased from the Navajo Nation. APS, on behalf of the Four Corners participants, negotiated amendments to the existing facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. The DOI issued a Record of Decision on July 17, 2015 approving the 25-year site lease extension for Four Corners, authorizes continued mining operations to supply the remaining units at Four Corners, renews transmission line and access road rights-of-way on the Navajo and Hopi Reservations, and accepts the proposed mining plan for the Navajo Mine.

The Four Corners participants' obligations to comply with EPA's final BART determinations, coupled with the financial impact of climate change regulation or legislation, other environmental regulations, and other business or regulatory considerations, could jeopardize the economic viability of Four Corners or the ability of individual participants to continue their participation in Four Corners.

Four Corners Federal Agency Lawsuit – On April 20, 2016, several environmental groups filed a lawsuit against OSM and other federal agencies in the United States District Court for the District of Arizona in connection with their issuance of the approvals that extended the life of Four Corners and the adjacent mine. The lawsuit alleges that these federal agencies violated both the ESA and NEPA in providing the federal approvals necessary to extend operations at Four Corners and the adjacent mine past July 6, 2016. The court granted an APS motion to intervene in the litigation on August 3, 2016. On September 15, 2016, NTEC, the current owner of the mine providing coal to Four Corners, filed a motion to intervene for the limited purpose of seeking dismissal of the lawsuit based on NTEC's tribal sovereign immunity. On September 11, 2017, the court granted NTEC's motion and dismissed the case with prejudice, terminating the proceedings. The environmental group plaintiffs filed a Notice of Appeal of the dismissed order in the United States Court of Appeals for the Ninth Circuit on November 9, 2017. PNM cannot predict if such appeal will be successful and, if it is successful, the outcome of further district court proceedings.

Carbon Dioxide Emissions

On August 3, 2015, EPA established final standards to limit CO_2 emissions from power plants. EPA took three separate but related actions in which it: (1) established the final carbon pollution standards for new, modified, and reconstructed power plants; (2) established the final Clean Power Plan to set standards for carbon emission reductions from existing power plants; and (3) released a proposed federal plan associated with the final Clean Power Plan. The Clean Power Plan was published on October 23, 2015.

Multiple states, utilities, and trade groups filed petitions for review in the DC Circuit to challenge both the Carbon Pollution Standards for new sources and the Clean Power Plan for existing sources. Numerous parties also simultaneously filed motions to stay the Clean Power Plan during the litigation. On January 21, 2016, the DC Circuit denied petitions to stay the Clean Power Plan, but 29 states and state agencies successfully petitioned the US Supreme Court for a stay, which was granted on February 9, 2016. The decision means the Clean Power Plan is not in effect and neither states nor sources are obliged to comply with its requirements. With the US Supreme Court stay in place, the DC Circuit heard oral arguments on

the merits of the Clean Power Plan on September 27, 2016 in front of a ten judge *en banc* panel. However, before the DC Circuit could issue an opinion, the Trump Administration asked that the case be held in abeyance while the rule is re-evaluated, which was granted.

On March 28, 2017, President Trump issued an Executive Order on Energy Independence. The order puts forth two general policies: promote clean and safe development of energy resources, while avoiding regulatory burdens, and ensure electricity is affordable, reliable, safe, secure, and clean. The order directs the EPA Administrator to immediately review and, if appropriate and consistent with law, suspend, revise, or rescind (1) the Clean Power Plan, (2) the New Source Performance Standards for GHG from new, reconstructed, or modified electric generating units, (3) the Proposed Clean Power Plan Model Trading Rules, and (4) the Legal Memorandum supporting the Clean Power Plan. It also directs the EPA Administrator to notify the US Attorney General of his intent to review rules subject to pending litigation so that the US Attorney General may notify the court and, in his discretion, request that the court delay further litigation pending completion of the reviews. In response to the Executive Order, EPA filed a petition with the DC Circuit requesting the cases challenging the Clean Power Plan be held in abeyance until 30 days after the conclusion of EPA's review and any subsequent rulemaking, which was granted. In addition, the DC Circuit issued a similar order in connection with a motion filed by EPA to hold cases challenging the NSPS in abeyance.

On October 10, 2017, EPA issued a NOPR proposing to repeal the Clean Power Plan and filed its status report with the court requesting the case be held in abeyance until the completion of the rulemaking on the proposed repeal. The NOPR proposes a legal interpretation concluding that the Clean Power Plan exceeds EPA's statutory authority. Under the proposed interpretation,

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Section 111(d) limits EPA's authority to adopt performance standards to only those physical and operational changes that can be implemented within an individual source. Therefore, measures in the Clean Power Plan that would require power generators to change their energy portfolios by shifting generation from coal to gas and from fossil fuel to renewable energy exceed EPA's statutory authority. The NOPR was published in the Federal Register on October 16, 2017, starting a 60-day public comment period and the EPA has indicated that it will continue to accept comments until April 26, 2018. Any final rule will be subject to judicial review. In a separate but related action, on December 28, 2017, EPA published the Advance Notice of Proposed Rulemaking for replacement of the Clean Power Plan. EPA indicated it has not determined whether it will promulgate a new rule under section 111(d) or what form a new rule would take, but is seeking public comment on that question.

The proposed federal plan released concurrently with the Clean Power Plan is important to Four Corners and the Navajo Nation. Since the Navajo Nation does not have primacy over its air quality program, EPA would be the regulatory authority responsible for implementing the Clean Power Plan on the Navajo Nation if the Clean Power Plan is ultimately sustained. In addition, the proposed rule recommended that EPA determine it is "necessary or appropriate" for EPA to regulate CO_2 emissions on the Navajo Nation. The comment period for the proposed rule closed on January 21, 2016. APS and PNM filed separate comments with EPA on EPA's draft plan and model trading rules, advocating that such a federal plan is neither necessary nor appropriate to protect air quality on the Navajo Nation. PNM is unable to predict the financial or operational impacts on Four Corners operations if the Clean Power Plan is ultimately implemented as proposed and EPA determines that a federal plan is necessary or appropriate for the Navajo Nation.

PNM's review of the CO_2 emission reductions standards under the Clean Power Plan is ongoing and the assessment of its impacts will depend on the proposed repeal of the Clean Power Plan, future GHG reduction rulemaking, litigation of any final rule, and other actions the Trump Administration is taking through judicial and regulatory proceedings. Accordingly, PNM cannot predict the impact these standards may have on its operations or a range of the potential costs of compliance, if any.

National Ambient Air Quality Standards ("NAAQS")

The CAA requires EPA to set NAAQS for pollutants considered harmful to public health and the environment. EPA has set NAAQS for certain pollutants, including NOx, SO_2, ozone, and particulate matter. In 2010, EPA updated the primary NOx and SO_2 NAAQS to include a 1-hour maximum standard while retaining the annual standards for NOx and SO_2 and the 24-hour SO_2 standard. New Mexico is in attainment for the 1-hour NOx NAAQS. On May 13, 2014, EPA released the draft data requirements rule for the 1-hour SO_2 NAAQS, which directs state and tribal air agencies to characterize current air quality in areas with large SO_2 sources to identify maximum 1-hour SO_2 concentrations. The proposed rule also describes the process and timetable by which air regulatory agencies would characterize air quality around large SO_2 sources through ambient monitoring or modeling. This characterization will result in these areas being designated as attainment, nonattainment, or unclassified for compliance with the 1-hour SO_2 NAAQS. On March 2, 2015, the United States District Court for the Northern District of California approved a settlement that imposes deadlines for EPA to identify areas that violate the NAAQS standards for 1-hour SO_2 emissions. The settlement results from a lawsuit brought by Earthjustice on behalf of the Sierra Club and the Natural Resources Defense Council under the CAA. The consent decree requires the following: (1) within 16 months of the consent decree entry, EPA must issue area designations for areas containing non-retiring facilities that either emitted more than 16,000 tons of SO_2 in 2012 or emitted more than 2,600 tons with an emission rate of 0.45 lbs/MMBTU or higher in 2012; (2) by December 2017, EPA must issue designations for areas for which states have not adopted a new monitoring network under the proposed data requirements rule; and (3) by December 2020, EPA must issue designations for areas for which states have adopted a new monitoring network under the proposed data requirements rule. SJGS and Four Corners SO_2 emissions are below the thresholds set forth in (1) above. EPA regions sent letters to state environmental agencies explaining how EPA plans to implement the consent decree. The letters outline the schedule that EPA expects states to follow in moving forward with new SO_2 non-attainment designations. NMED did not receive a letter.

On August 11, 2015, EPA released the Data Requirements Rule for SO_2, telling states how to model or monitor to determine attainment or nonattainment with the new 1-hour SO_2 NAAQS. On June 3, 2016, NMED notified PNM that air quality modeling results indicated that SJGS was in compliance with the standard. In January 2017, NMED submitted their formal modeling report regarding attainment status to EPA. The modeling indicated that no area in New Mexico exceeds the 1-hour SO_2 standard. In July of each year, NMED will submit an annual report to EPA documenting annual SO_2 emissions from SJGS and the associated compliance status.

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On May 14, 2015, PNM received an amendment to its NSR air permit for SJGS, which reflects the revised state implementation plan for regional haze BART and requires the installation of SNCRs as described above. The revised permit also requires the reduction of SO_2 emissions to 0.10 pound per MMBTU on SJGS Units 1 and 4 and the installation of BDT equipment modifications for the purpose of reducing fugitive emissions, including NOx, SO_2, and particulate matter. These reductions should help SJGS meet the NAAQS for these

constituents. The BDT equipment modifications were installed at the same time as the SNCRs, in order to most efficiently and cost effectively conduct construction activities at SJGS. See Regional Haze – SJGS above.

On October 1, 2015, EPA finalized the new ozone NAAQS and lowered both the primary and secondary 8-hour standard from 75 parts per billion ("ppb") to 70 ppb. With ozone standards becoming more stringent, fossil-fueled generation units will come under increasing pressure to reduce emissions of NOx and volatile organic compounds, and to generate emission offsets for new projects or facility expansions located in nonattainment areas.

On November 10, 2015, EPA proposed a rule revising its Exceptional Events Rule, which outlines the requirements for excluding air quality data (including ozone data) from regulatory decisions if the data is affected by events outside an area's control. The proposed rule is timely in light of the new more stringent ozone NAAQS final rule since western states like New Mexico and Arizona are particularly subject to elevated background ozone transport from natural local sources such as wildfires, and transported via winds from distant sources, such as the stratosphere or another region or country.

On February 25, 2016, EPA released guidance on area designations, which states used to determine their initial designation recommendations by October 1, 2016. EPA recommended that states and tribes use the three most recent years of quality assured monitoring data available (e.g., 2013 to 2015) to recommend designations. In their submittals, states and tribes were also able to use preliminary 2016 data. EPA was expected to release final designations of attainment/nonattainment for areas by October 1, 2017. On June 6, 2017, the EPA Administrator sent letters to state governors announcing that EPA was extending, by one year, the deadline for promulgating area designations. However, on August 2, 2017, the Trump Administration reversed the decision to extend the deadline to issue area designations, thereby requiring EPA to issue designations for ozone attainment areas by October 1, 2017.

NMED published its 2015 Ozone NAAQS Designation Recommendation Report on September 2, 2016. In New Mexico, NMED is designating only a small area in southern Dona Ana County as non-attainment for ozone. NMED will have responsibility for bringing this non-attainment area into compliance and will look at all sources of NO_x and volatile organic compounds since these are the pollutants that form ground-level ozone. According to NMED's website, "If emissions from Mexico keep New Mexico from meeting the standards, the New Mexico area could remain non-attainment but would not face more stringent requirements over time."

On November 6, 2017, EPA released a final rule establishing some, but not all, initial area designations. In that final rule, EPA designated 2,646 counties (representing about 85% of the counties in the U.S.) as attainment/unclassifiable, and three counties in Washington as unclassifiable. San Juan County, New Mexico, where SJGS and Four Corners are located, is designated as attainment/unclassifiable. On December 21, 2017, EPA issued a notice of availability of its intended designations for the remaining undesignated areas. EPA stated that it intended to address the remaining areas in a separate future action, but did not specify a time frame for doing so. Under the CAA, EPA was required to promulgate area designations no later than October 1, 2017. The notice announces the availability of "120-day letters," which were sent directly to states and tribes on December 20, 2017, and contain EPA's intended air quality designations for the remaining areas. The only county in New Mexico designated as non-attainment is Dona Ana County. By February 28, 2018, states and tribes must provide EPA any additional information they would like EPA to consider before it promulgates final designations. EPA stated it intends to finalize designations for all areas addressed in the 120-day letters no later than April 30, 2018.

By October 2018, NMED is required to submit an infrastructure SIP that provides the basic air quality management program to implement the revised ozone standard. These plans are generally due within 36 months from the date of designation and are expected to be submitted to EPA by October 1, 2020.

PNM does not believe there will be material impacts to its facilities as a result of NMED's nonattainment designation of the small area within Dona Ana County. Until EPA approves attainment designations for the Navajo Nation and releases a proposal to implement the revised ozone NAAQS, APS is unable to predict what impact the adoption of these standards may have on Four Corners. PNM cannot predict the outcome of this matter.

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WEG v. OSM NEPA Lawsuit

In February 2013, WEG filed a Petition for Review in the United States District Court of Colorado against OSM challenging federal administrative decisions affecting seven different mines in four states issued at various times from 2007 through 2012. In its petition, WEG challenges several unrelated mining plan modification approvals, which were each separately approved by OSM. WEG alleges various NEPA violations against OSM, including, but not limited to, OSM's alleged failure to provide requisite public notice and participation, alleged failure to analyze certain environmental impacts, and alleged reliance on outdated and insufficient documents. WEG's petition seeks various forms of relief, including a finding that the federal defendants violated NEPA by approving the mine plans; voiding, reversing, and remanding the various mining modification approvals; enjoining the federal defendants from re-issuing the mining plan approvals for the mines until compliance with NEPA has been demonstrated; and enjoining operations at the seven mines.

Of the fifteen claims for relief in the WEG Petition, two concern SJCC's San Juan mine. WEG's allegations concerning the San Juan mine arise from OSM administrative actions in 2008. SJCC intervened in this matter. The court granted SJCC's motion to sever its claims from the lawsuit and transfer venue to the United States District Court for the District of New Mexico. In July 2016, OSM filed a Motion for Voluntary Remand to allow the agency to conduct a new environmental analysis. On August 31, 2016, the court entered an order remanding the matter to OSM for the completion of an EIS by August 31, 2019. The court ruled that mining operations may continue in the interim and the litigation is administratively closed. If OSM does not complete the EIS within the time frame provided, the court will order immediate *vacatur* of the mining plan at issue, absent a further court order based on good cause shown. On March 22, 2017, OSM issued its Notice of Intent to initiate the public scoping process and prepare an EIS for the project. The Notice of Intent provided that, in addition to analyzing the environmental effects of the mining project, the EIS will also analyze the indirect effects of coal combustion at SJGS. The public comment period ended on May 8, 2017 and the EIS resource data submittal phase was completed in November 2017. The draft EIS is expected to be available for public comment in mid-2018. PNM cannot currently predict the outcome of this matter.

Navajo Nation Environmental Issues

Four Corners is located on the Navajo Reservation and is held under an easement granted by the federal government, as well as a lease from the Navajo Nation. The Navajo Acts purport to give the Navajo Nation Environmental Protection Agency authority to promulgate regulations covering air quality, drinking water, and pesticide activities, including those activities that occur at Four Corners. In October 1995, the Four Corners participants filed a lawsuit in the District Court of the Navajo Nation challenging the applicability of the Navajo Acts to Four Corners. In May 2005, APS and the Navajo Nation signed an agreement resolving the dispute regarding the Navajo Nation's authority to adopt operating permit regulations under the Navajo Nation Air Pollution Prevention and Control Act. As a result of this agreement, APS sought, and the court granted, dismissal of the pending litigation in the Navajo Nation Supreme Court and the Navajo Nation District Court, to the extent the claims relate to the CAA. The agreement does not address or resolve any dispute relating to other aspects of the Navajo Acts. PNM cannot currently predict the outcome of these matters or the range of their potential impacts.

Cooling Water Intake Structures

EPA signed its final cooling water intake structures rule on May 16, 2014, which establishes national standards for certain cooling water intake structures at existing power plants

and other facilities under the Clean Water Act to protect fish and other aquatic organisms by minimizing impingement mortality (the capture of aquatic wildlife on intake structures or against screens) and entrainment mortality (the capture of fish or shellfish in water flow entering and passing through intake structures). The final rule was published on August 15, 2014 and became effective October 14, 2014.

The final rule allows multiple compliance options and considerations for site specific conditions and the permit writer is granted a significant amount of discretion in determining permit requirements, schedules, and conditions. To minimize impingement mortality, the rule provides operators of facilities, such as SJGS and Four Corners, seven options for meeting Best Technology Available ("BTA") standards for reducing impingement. SJGS has a closed-cycle recirculating cooling system, which is a listed BTA and may also qualify for the "*de minimis* rate of impingement" based on the design of the intake structure. To minimize entrainment mortality, the permitting authority must establish the BTA for entrainment on a site-specific basis, taking into consideration an array of factors, including endangered species and social costs and benefits. Affected sources must submit source water baseline characterization data to the permitting authority to assist in the determination. Compliance deadlines under the rule are tied to permit renewal and will be subject to a schedule of compliance established by the permitting authority.

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The rule is not clear as to how it applies and what the compliance timelines are for facilities like SJGS that have a cooling water intake structure and only a multi-sector general stormwater permit. PNM is working with EPA regarding this issue. However, PNM does not expect material changes as a result of any requirements that may be imposed upon SJGS. The requirements related to Four Corners will be addressed in a subsequent NPDES permitting cycle that will determine APS's costs to comply with the rule. PNM does not expect such costs to be material.

Effluent Limitation Guidelines

On June 7, 2013, EPA published proposed revised wastewater effluent limitation guidelines establishing technology-based wastewater discharge limitations for fossil fuel-fired electric power plants. EPA's proposal offered numerous options that target metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and non-chemical metal cleaning waste operations. All proposed alternatives establish a "zero discharge" effluent limit for all pollutants in fly ash transport water. Requirements governing bottom ash transport water differ depending on which alternative EPA ultimately chooses and could range from effluent limits based on Best Available Technology Economically Achievable to "zero discharge" effluent limits.

EPA signed the final Steam Electric Effluent Guidelines rule on September 30, 2015. The final rule, which became effective on January 4, 2016, phases in the new, more stringent requirements in the form of effluent limits for arsenic, mercury, selenium, and nitrogen for wastewater discharged from wet scrubber systems and zero discharge of pollutants in ash transport water that must be incorporated into plants' NPDES permits. Each plant must comply between 2018 and 2023 depending on when it needs a new/revised NPDES permit.

On April 14, 2017, EPA filed a motion with the United States Court of Appeals for the Fifth Circuit relating to ongoing litigation of the 2016 Steam Electric Effluent Guidelines rule. EPA asked the court to hold all proceedings in the case in abeyance until August 12, 2017 while EPA reconsiders the rule. EPA also asked to be allowed to file a motion on August 12, 2017 to inform the court if EPA wishes to seek a remand of any provisions of the rule so that EPA may conduct further rulemaking, if appropriate. The motion referred to the notice signed by the EPA Administrator on April 12, 2017, which announced EPA's intent to reconsider this rule, as well as EPA's administrative stay of the compliance deadlines. On August 22, 2017, the court granted the government's motion and the litigation is held in abeyance until EPA's further rulemaking has concluded.

On April 25, 2017, EPA published in the Federal Register a notice of postponement of certain compliance dates for the 2016 Steam Electric Effluent Guidelines rule, consistent with the EPA's decision to grant reconsideration of the rule. Specifically, the deadlines that will be postponed are the "best available technology" limitations and pretreatment standards for certain waste streams.

On September 18, 2017, EPA published the final rule for postponement of certain compliance dates that have not yet passed for the Effluent Limitations Guidelines rule, consistent with the EPA's decision to grant reconsideration of that rule. The final rule postponed the earliest date on which compliance with the effluent limitation guidelines for these waste streams would be required from November 1, 2018 until November 1, 2020.

Because SJGS is zero discharge for wastewater and is not required hold a NPDES permit, it is expected that minimal to no requirements will be imposed. Reeves Station, a PNM-owned gas-fired generating station, discharges cooling tower blowdown to a publicly owned treatment works and holds an NPDES permit. It is expected that minimal to no requirements will be imposed at Reeves

Four Corners may be required to change equipment and operating practices affecting boilers and ash handling systems, as well as change its waste disposal techniques. Until a draft NPDES permit is proposed for Four Corners, APS is uncertain what will be required to comply with the revised effluent limitations during the revised compliance timeframe (from November 1, 2020 through December 31, 2023). PNM is unable to predict the outcome of this matter or a range of the potential costs of compliance.

Santa Fe Generating Station

PNM and the NMED are parties to agreements under which PNM installed a remediation system to treat water from a City of Santa Fe municipal supply well, an extraction well, and monitoring wells to address gasoline contamination in the

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groundwater at the site of PNM's former Santa Fe Generating Station and service center. PNM believes the observed groundwater contamination originated from off-site sources, but agreed to operate the remediation facilities until the groundwater meets applicable federal and state standards or until the NMED determines that additional remediation is not required, whichever is earlier. The City of Santa Fe has indicated that since the City no longer needs the water from the well, the City would prefer to discontinue its operation and maintain it only

as a backup water source. However, for PNM's groundwater remediation system to operate, the water well must be in service. Currently, PNM is not able to assess the duration of this project or estimate the impact on its obligations if the City of Santa Fe ceases to operate the water well.

The Superfund Oversight Section of the NMED also has conducted multiple investigations into the chlorinated solvent plume in the vicinity of the site of the former Santa Fe Generating Station. In February 2008, a NMED site inspection report was submitted to EPA, which states that neither the source nor extent of contamination has been determined and that the source may not be the former Santa Fe Generating Station. Results of tests conducted by NMED in April 2012 and April 2013 showed elevated concentrations of nitrate in three monitoring wells and an increase in free-phase hydrocarbons in another well. PNM conducted similar site-wide sampling activities in April 2014 and obtained results similar to the 2013 data. As part of this effort, PNM also collected a sample of hydrocarbon product for "fingerprint" analysis from a monitoring well located on the northeastern corner of the property. This analysis indicated that the hydrocarbon product was a mixture of newer and older fuels, and the location of the monitoring well suggests that the hydrocarbon product is likely from offsite sources. PNM does not believe the former generating station is the source of the increased levels of free-phase hydrocarbons, but no conclusive determinations have been made. However, it is possible that PNM's prior activities to remediate hydrocarbon contamination, as conducted under an NMED-approved plan, may have resulted in increased nitrate levels. Therefore, PNM has agreed to monitor nitrate levels in a limited number of wells under the terms of the renewed discharge permit for the former generating station.

Effective December 22, 2015, PNM and NMED entered into a memorandum of understanding to address changing groundwater quality conditions at the site. Under the memorandum, PNM will continue hydrocarbon investigation of the site under the supervision of NMED and qualified costs of the work will be eligible for payment through the New Mexico Corrective Action Fund ("CAF"), which is administered by the NMED Petroleum Storage Tank Bureau. Among other things, money in the CAF is available to NMED to make payments to or on behalf of owners and operators for corrective action taken in accordance with statutory and regulatory requirements to investigate, minimize, eliminate, or clean up a release. PNM's work plan and cost estimates for specific groundwater investigation tasks were approved by the Petroleum Storage Tank Bureau. PNM submitted a monitoring plan consisting of a compilation of the data associated with the recent monitoring activities conducted under the CAF to NMED on October 3, 2016. PNM has completed all CAF-related work associated with the monitoring plan and has received NMED's approval. Under the next phase, PNM's contractor prepared a scope of work, which PNM and NMED have approved, for the installation of additional monitoring wells and additional sampling of certain existing monitoring wells at the site. Work is expected to commence in March 2018. Qualified costs of this work will be eligible for payment through the CAF.

PNM is unable to predict the outcome of these matters.

Coal Combustion Byproducts Waste Disposal

CCBs consisting of fly ash, bottom ash, and gypsum generated from coal combustion at SJGS are currently disposed of in the surface mine pits adjacent to the plant. SJGS does not operate any CCB impoundments or landfills. The NMMMD currently regulates placement of ash in the San Juan mine with federal oversight by the OSM. APS disposes of CCBs in ash ponds and dry storage areas at Four Corners. Ash management at Four Corners is regulated by EPA and the New Mexico State Engineer's Office.

In June 2010, EPA published a proposed rule that included two options for waste designation of coal ash. One option was to regulate CCBs as a hazardous waste, which would allow EPA to create a comprehensive federal program for waste management and disposal of CCBs. The other option was to regulate CCBs as a non-hazardous waste, which would provide EPA with the authority to develop performance standards for waste management facilities handling CCBs and would be enforced primarily by state authorities or through citizen suits. Both options allow for continued use of CCBs in beneficial applications.

On December 19, 2014, EPA issued its coal ash rule, including a non-hazardous waste determination for coal ash. Coal ash will be regulated as a solid waste under Subtitle D of RCRA. The rule sets minimum criteria for existing and new CCB landfills and existing and new CCB surface impoundments and all lateral expansions consisting of location restrictions, design and operating criteria; groundwater monitoring and corrective action; closure requirements and post closure care; and recordkeeping, notification, and internet posting requirements. Because the rule is promulgated under Subtitle D, it does not require regulated facilities to

obtain permits, does not require the states to adopt and implement the new rules, and is not within EPA's enforcement jurisdiction. Instead, the rule's compliance mechanism is for a state or citizen group to bring a RCRA citizen suit in federal district court against any facility that is alleged to be in non-compliance with the new requirements. EPA published the final CCB rule in the Federal Register on April 17, 2015, with an effective date of October 19, 2015. Based upon the requirements of the final rule, PNM conducted a CCB assessment at SJGS and made minor modifications at the plant to ensure that there are no facilities which would be considered impoundments or landfills under the rule. PNM does not expect the rule to have a material impact on operations, financial position, or cash flows.

As indicated above, CCBs at Four Corners are currently disposed of in ash ponds and dry storage areas. The CCB rule requires ongoing, phased groundwater monitoring. By October 17, 2017, utilities that own or operate CCB disposal units, such as those at Four Corners must have collected sufficient groundwater sampling data to initiate a detection monitoring program. To the extent that certain threshold constituents are identified through this initial detection monitoring at levels above the CCB rule's standards, the rule requires the initiation of an assessment monitoring program by April 15, 2018. If this assessment monitoring program reveals concentrations of certain constituents above the CCB rule standards that trigger remedial obligations, a corrective measures evaluation must be completed by January 2019. Depending upon the results of such groundwater monitoring and data evaluations, Four Corners may be required to take corrective actions, the costs of which cannot be reasonably estimated at this time.

Pursuant to a June 24, 2016 order by the DC Circuit in litigation by industry and environmental groups challenging EPA's CCB regulations, EPA is required to complete a rulemaking proceeding by June 2019 to address specific technical issues related to the handling of CCBs. EPA is not required to take final action approving the inclusion of boron, but EPA must propose and consider its inclusion. Should EPA take final action adding boron to the list of groundwater constituents, corrective action may be required. Any resulting corrective action measures may increase costs of compliance with the CCB rule at coal-fired generating facilities. At this time, PNM cannot predict when EPA will commence its rulemaking concerning boron or the eventual results of those proceedings.

On December 16, 2016, the Water Infrastructure Improvements for the Nation Act (the "WIIN Act") was signed into law to address critical water infrastructure needs in the United States. The WIIN Act contains a number of provisions requiring EPA to modify the self-implementing provisions of the current CCB rules under Subtitle D. Among other things, the WIIN Act provides for the establishment of state and EPA permit programs for CCBs, provides flexibility for states to incorporate the EPA final rule for CCBs or develop other criteria that are at least as protective as the EPA's final rule, and requires EPA to approve state permit programs within 180 days of submission by the state for approval. As a result, the CCB rule is no longer self-implementing and there will either be a state or federal permit program. Subject to Congressional appropriated funding, EPA will implement the permit program in states that choose not to implement a program. Until permit programs are in effect, EPA has authority to directly enforce the self-implementing CCB rule. For facilities located within the boundaries of Native American tribal reservations, such as the Navajo Nation where Four Corners is located, EPA is required to develop a federal permit program regardless of appropriated funds. EPA has yet to undertake rulemaking proceedings to implement the CCB provisions of the WIIN Act. There is no time line for establishing either state or federal permitting programs. APS recently filed a comment letter with EPA seeking clarification as to when and how EPA would be initiating permit proceedings for facilities on tribal reservations, including Four Corners. PNM is unable to predict when EPA will be issuing permits for Four Corners.

On September 13, 2017, EPA agreed to evaluate whether to revise the CCB regulations based upon utility industry petitions for EPA to reconsider the RCRA Subtitle D regulations for CCBs, which were premised in part on the provisions of the WIIN Act. In light of the WIIN Act and the petitions for rulemaking, the EPA is considering making additional changes to the CCB rule to provide flexibility to state programs consistent with the WIIN Act. With respect to ongoing litigation initiated by industry and environmental groups challenging the legality of the CCB regulations and pursuant to an order issued by the DC Circuit, EPA filed a status report on November 15, 2017 on the challenges to the CCB rule identifying provisions it intends to reconsider. On November 20, 2017, the DC Circuit heard oral arguments from industry groups, environmentalists, and EPA. EPA and the industry groups argued the court should postpone adjudication until EPA completes the reconsideration process for the affected provision. On December 20, 2017, a proposal to remand the CCB rule was transmitted to the Office of Management and Budget for interagency review.

The CCB rule does not cover mine placement of coal ash. OSM is expected to publish a proposed rule covering mine placement in the future and will likely be influenced by EPA's rule. PNM cannot predict the outcome of OSM's proposed rulemaking

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regarding CCB regulation, including mine placement of CCBs, or whether OSM's actions will have a material impact on PNM's operations, financial position, or cash flows. PNM would seek recovery from its ratepayers of all CCB costs that are ultimately incurred.

Other Commitments and Contingencies

Coal Supply

SJGS

The coal requirements for SJGS are supplied by SJCC. SJCC holds certain federal, state, and private coal leases. Through January 31, 2016, SJCC was a wholly-owned subsidiary of BHP and supplied processed coal for operation of SJGS under an underground coal sales agreement ("UG-CSA") that was to expire on December 31, 2017. The parties to the UG-CSA were SJCC, PNM, and Tucson. Under the UG-CSA, SJCC was reimbursed for all costs for mining and delivering the coal, including an allocated portion of administrative costs, and received a return on its investment. In addition to coal delivered to meet the current needs of SJGS, PNM prepaid SJCC for certain coal mined but not yet delivered to the plant site. At December 31, 2017 and 2016, prepayments for coal (including amounts purchased from the existing SJGS participants discussed below), which are included in other current assets, amounted to $26.3 million and $48.7 million.

In conjunction with the activities undertaken to comply with the CAA for SJGS, as discussed above, PNM and the other owners of SJGS evaluated alternatives for the supply of coal to SJGS after the expiration of the UG-CSA. Following extensive negotiations among the SJGS participants, the owner of SJCC, and third-party miners, agreements were negotiated under which the ownership of SJCC would transfer to a new third-party miner and PNM would enter into a new coal supply agreement and agreements for CCB disposal and mine reclamation services with SJCC on or about January 1, 2016. Effectiveness of the agreements was dependent upon the closing of the purchase of SJCC by the new third-party miner and the finalization of the SJGS RA and other agreements, which along with regulatory approvals were necessary for the restructuring of ownership in SJGS to be consummated.

On July 1, 2015, PNM and Westmoreland Coal Company ("Westmoreland") entered into a new coal supply agreement ("SJGS CSA"), pursuant to which Westmoreland is to supply all of the coal requirements of SJGS through June 30, 2022. PNM and Westmoreland also entered into agreements under which Westmoreland is to provide CCB disposal and mine reclamation services for SJGS. Contemporaneous with the entry into the coal-related agreements, Westmoreland entered into a stock purchase agreement (the "Stock Purchase Agreement") on July 1, 2015 to acquire all of the capital stock of SJCC. In addition, PNM, Tucson, SJCC, and SJCC's owner entered into an agreement to terminate the existing UG-CSA upon the effective date of the new SJGS CSA.

The SJGS CSA became effective as of 11:59 PM on January 31, 2016, upon the closing under the Stock Purchase Agreement. Upon closing under the Stock Purchase Agreement, Westmoreland's rights and obligations under the SJGS CSA and the agreements for CCB disposal and mine reclamation services were assigned to SJCC. Westmoreland has guaranteed SJCC's performance under the SJGS CSA.

Pricing under the SJGS CSA is primarily fixed, adjusted to reflect general inflation. The pricing structure takes into account that SJCC has been paid for coal mined but not delivered, as discussed above. PNM has the option to extend the SJGS CSA, subject to negotiation of the term of the extension and compensation to the miner. In order to extend, PNM must give written notice of that intent by July 1, 2018 and the parties must agree to the terms of the extension by January 1, 2019. However, as discussed in Note 17, PNM's 2017 IRP shows that retirement of PNM's SJGS capacity in 2022 would be cost-effective for customers. If retirement of SJGS is approved by the NMPRC, there will be no need to extend the SJGS CSA.

The SJGS RA sets forth terms under which PNM acquired the coal inventory, including coal mined but not delivered, of the exiting SJGS participants as of January 1, 2016 and supplied coal to the SJGS exiting participants for the period from January 1, 2016 through December 31, 2017 and is supplying coal to the SJGS remaining participants over the term of the SJGS CSA. Coal costs under the SJGS CSA are significantly less than under the previous arrangement with SJCC. Since substantially all of PNM's coal costs are passed through the FPPAC, the benefit of the reduced costs and the economic benefits of the coal inventory arrangement with the exiting owners are passed through to PNM's customers.

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In support of the closing under the Stock Purchase Agreement and to facilitate PNM customer savings, NM Capital, a wholly-owned subsidiary of PNMR, provided funding of $125.0 million (the "Westmoreland Loan") to Westmoreland San Juan, LLC ("WSJ"), a ring-fenced, bankruptcy-remote, special-purpose entity that is a subsidiary of Westmoreland, to finance WSJ's purchase of the stock of SJCC (including an insignificant affiliate) under the Stock Purchase Agreement. NM Capital was able to provide the $125.0 million financing to WSJ by first entering into a $125.0 million term loan agreement (the "BTMU Term Loan Agreement") with BTMU, as lender and administrative agent. The BTMU Term Loan Agreement became effective as of February 1, 2016, matures on February 1, 2021, and bears interest at a rate based on LIBOR plus a customary spread. In connection with the BTMU Term Loan Agreement, PNMR, as parent company of NM Capital, has guaranteed NM Capital's obligations to BTMU. The balance outstanding under the BTMU Term Loan Agreement was $50.1 million at December 31, 2017 and $45.1 million at February 20, 2018.

The Westmoreland Loan is a $125.0 million loan agreement among NM Capital, as lender, WSJ, as borrower, SJCC and its affiliate, as guarantors, BTMU, as administrative agent, and MUFG Union Bank, N.A., as depository bank. The Westmoreland Loan became effective as of February 1, 2016, and matures on February 1, 2021. The interest rate on the Westmoreland Loan escalates over time and was initially a rate of 7.25% plus LIBOR. Such rate was 9.25% plus LIBOR for the period from February 1, 2017 through January 31, 2018 and is 12.25% plus LIBOR for the period from February 1, 2018 through January 31, 2019. WSJ must pay principal and interest quarterly to NM Capital in accordance with an amortization schedule. In addition, the Westmoreland Loan requires that all cash flows of WSJ, in excess of normal operating expenses, capital additions, and operating reserves, be utilized for principal and interest payments under the loan until it is fully repaid. At December 31, 2017, the amount outstanding under the Westmoreland Loan was $56.6 million. Reflecting the principal payment of $5.6 million that was paid when due on February 1, 2018, the balance of the Westmoreland Loan was $51.0 million as of February 20, 2018. The Westmoreland Loan is secured by the assets of and the equity interests in SJCC and its affiliate. The Westmoreland Loan also includes customary representations and warranties, covenants, and events of default. There are no prepayment penalties.

In connection with certain mining permits relating to the operation of the San Juan mine, SJCC is required to post reclamation bonds of $118.7 million with the NMMMD. In order to facilitate the posting of reclamation bonds by sureties on behalf of SJCC, PNMR entered into letter of credit arrangements with a bank under which letters of credit aggregating $30.3 million have been issued.

Four Corners

APS purchased all of Four Corners' coal requirements from a supplier that was also a subsidiary of BHP and had a long-term lease of coal reserves with the Navajo Nation. That contract was to expire on July 6, 2016 with pricing determined using an escalating base-price. On December 30, 2013, ownership of the mine was transferred to NTEC, an entity owned by the Navajo Nation, and a new coal supply contract for Four Corners (the "Four Corners CSA"), beginning in July 2016 and expiring in 2031, was entered into with NTEC. The BHP subsidiary was retained as the mine manager and operator through December 2016. Bisti Fuels Company, LLC, a subsidiary of The North American Coal Corporation, took over management and operation of the mine effective January 1, 2017. The average coal price per ton under the new contract was approximately 51% higher in the twelve months ended June 30, 2017 than in the twelve months ended June 30, 2016, excluding the disputed amounts discussed below. The contract provides for pricing adjustments over its term based on economic indices. PNM anticipates that its share of the increased costs will be recovered through its FPPAC.

Four Corners Coal Supply Arbitration – The owners of Four Corners are obligated to purchase a specified minimum amount of coal each contract year and to pay for any shortfall of coal that they fail to take delivery of below the minimum amount, except when caused by "uncontrollable forces" as defined in the Four Corners CSA. On June 13, 2017, APS received a demand for arbitration from NTEC in connection with the Four Corners CSA. NTEC originally sought a declaratory judgment to support its interpretation of a provision regarding uncontrollable forces in the agreement relating to the annual minimum quantities of coal to be purchased by the Four Corners owners. NTEC also alleged a shortfall in those purchases for the initial contract year, which ended June 30, 2017, of which PNM's share is estimated to be approximately $6.5 million. On September 20, 2017, NTEC amended its demand for arbitration removing the request for a declaratory judgment and is now only seeking relief for the alleged shortfall in purchases in the initial contract year. PNM anticipates that substantially all of any amount it ultimately is required to pay would be passed through to customers under PNM's FPPAC. Although PNM cannot predict the timing or outcome of the arbitration, the outcome is not expected to have a material impact on its financial position, results of operations or cash flows.

Coal Mine Reclamation

In conjunction with the proposed shutdown of SJGS Units 2 and 3 to comply with the BART requirements of the CAA, an updated coal mine reclamation study was requested by the SJGS participants. In 2013, PNM updated its study of the final reclamation costs for both the surface mines that previously provided coal to SJGS and the current underground mine providing coal and revised its estimates of the final reclamation costs. This estimate reflected that, with the proposed shutdown of SJGS Units 2 and 3 described above, the mine providing coal to SJGS would continue to operate through 2053, the anticipated life of SJGS. The 2013 coal mine reclamation study indicated reclamation costs had increased, including significant increases due to the proposed shutdown of SJGS Units 2 and 3, which would reduce the amount of CCBs generated over the remaining life of SJGS and result in a significant increase in the amount of fill dirt required to remediate the underground mine area thereby increasing the overall reclamation costs. As discussed under Coal Combustion Byproducts Waste Disposal above, SJGS currently disposes of CCBs from the plant in the surface mine pits adjacent to the plant.

In 2015, PNM updated its final reclamation costs estimates to reflect the terms of the new reclamation services agreement with Westmoreland, discussed above, and changes resulting from the approval of the 2015 SJCC Mine Permit Plan. The 2015 reclamation cost estimate reflected that the scope and pricing structure of the reclamation service agreement with Westmoreland would significantly increase reclamation costs. In addition, design plan changes, updated regulatory expectations, and common mine reclamation practices incorporated into the 2015 SJCC Mine Permit reflect an increase in the 2015 reclamation cost estimate. The impacts of these increases, amounting to $16.5 million, were recorded at December 31, 2015 and were reflected in regulatory disallowances and restructuring costs on the Consolidated Statements of Earnings.

Upon effectiveness of the SJGS CSA and the SJGS RA, PNM, on behalf of the SJGS owners, coordinated a more detailed coal mine reclamation cost study, which was completed in the third quarter of 2016. To complete the study, PNM was provided access to the mine site and obtained supporting data from Westmoreland, allowing for the 2015 study to be refined with a more extensive engineering analysis. This reclamation cost estimate reflected the terms of the new reclamation services agreement with Westmoreland and continuation of mining operations through 2053. The study indicated an increase in the reclamation cost estimate. PNM's $4.5 million share of the increase was recorded in 2016 and is reflected in regulatory disallowances and restructuring costs in the Consolidated Statements of Earnings. The current estimate for decommissioning the mine serving Four Corners reflects the operation of the mine through 2031, the term of the new agreement for coal supply.

Based on the 2016 estimates and PNM's current ownership share of SJGS, PNM's remaining payments for mine reclamation, in future dollars, are estimated to be $100.4 million for the surface mines at both SJGS and Four Corners and $127.1 million for the underground mine at SJGS as of December 31, 2017. At December 31, 2017 and 2016, liabilities, in current dollars, of $41.4 million and $41.0 million for surface mine reclamation and $14.7 million and $14.0 million for underground mine reclamation were recorded in other deferred credits.

As discussed in Note 17, PNM filed its 2017 IRP on July 3, 2017. The conclusions contained in the 2017 IRP indicate that it would be cost beneficial to PNM's customers for PNM to retire its SJGS capacity in 2022 and for PNM to exit its ownership interest in Four Corners in 2031. The 2017 IRP is not a final determination of PNM's future generation portfolio. Retiring PNM's share of SJGS capacity and exiting Four Corners would require NMPRC approval of abandonment filings, which PNM would make at appropriate times in the future. If the NMPRC orders the abandonment of those facilities, PNM would be required to remeasure its liability for coal mine reclamation to reflect that reclamation activities would occur sooner than currently anticipated. The remeasurement would likely result in a significant increase in PNM's liability for SJGS mine reclamation due to a further increase in the amount of fill dirt required to remediate the mine areas thereby increasing the overall reclamation costs. PNM would record an additional amount when it is determined that the increase to the liability is probable and can be reasonably estimated, which would be dependent on receiving the NMPRC approvals indicated above. The amount of the increase in the liability would depend on the timing of those approvals and other regulatory actions, as well estimates made at that time of the costs to perform the future reclamation activities, as well as the then current inflation and discount rates. Preliminary calculations indicate the increase in PNM's liability for December 31, 2017 SJGS mine reclamation would be approximately $35 million for the surface mine and $5 million for the underground mine. PNM would record a regulatory asset for amounts recoverable from ratepayers under existing or future orders of the NMPRC and amounts not

recoverable would be expensed. PNM cannot predict what actions the NMPRC might take.

Under the terms of the SJGS CSA, PNM and the other SJGS owners are obligated to compensate SJCC for all reclamation costs associated with the supply of coal from the San Juan mine. The SJGS owners entered into a reclamation trust funds agreement to provide funding to compensate SJCC for post-term reclamation obligations under the UGCSA. As part of the restructuring of SJGS ownership (see SJGS Ownership Restructuring Matters above), the SJGS owners and PNMR Development negotiated the terms of an amended agreement to fund post-term reclamation obligations under the SJGS CSA. The trust funds agreement requires each owner to enter into an individual trust agreement with a financial institution as trustee, create an irrevocable reclamation trust, and periodically deposit funds into the reclamation trust for the owner's share of the mine reclamation obligation. Deposits, which are based on funding curves, must be made on an annual basis. As part of the restructuring of SJGS ownership discussed above, the SJGS participants agreed to adjusted interim trust funding levels. PNM funded $5.8 million in 2017, $7.0 million in 2016, and $4.3 million in 2015. Based on PNM's reclamation trust fund balance at December 31, 2017, the current funding curves indicate PNM's required contributions to its reclamation trust fund would be $8.3 million in 2018, $8.7 million in 2019, and $9.2 million in 2020.

Under the Four Corners CSA, which became effective on July 7, 2016, PNM is required to fund its ownership share of estimated final reclamation costs in thirteen annual installments, beginning on August 1, 2016, into an irrevocable escrow account solely dedicated to the final reclamation cost of the surface mine at Four Corners. PNM contributed $2.3 million in 2017 and $1.9 million in 2016 to the escrow account and anticipates providing additional funding of $2.3 million, $2.3 million, and $2.3 million in 2018, 2019, and 2020.

PNM collects a provision for surface and underground mine reclamation costs in its rates. The NMPRC has capped the amount that can be collected from retail customers for final reclamation of the surface mines at $100.0 million. Previously, PNM recorded a regulatory asset for the $100.0 million and recovers the amortization of this regulatory asset in rates. If future estimates increase the liability for surface mine reclamation, the excess would be expensed at that time. The reclamation amounts discussed above reflect PNM's estimates of its share of the revised costs. Regulatory determinations made by the NMPRC may also affect the impact on PNM. PNM is currently unable to determine the outcome of these matters or the range of possible impacts.

Continuous Highwall Mining Royalty Rate

In August 2013, the DOI Bureau of Land Management ("BLM") issued a proposed rulemaking that would retroactively apply the surface mining royalty rate of 12.5% to continuous highwall mining ("CHM"). Comments regarding the rulemaking were due on October 11, 2013 and PNM submitted comments in opposition to the proposed rule. There is no legal deadline for adoption of the final rule.

SJCC utilized the CHM technique from 2000 to 2003 and, with the approval of the Farmington, New Mexico Field Office of BLM to reclassify the final highwall as underground reserves, applied the 8.0% underground mining royalty rate to coal mined using CHM and sold to SJGS. In March 2001, SJCC learned that the DOI Minerals Management Service ("MMS") disagreed with the application of the underground royalty rate to CHM. In August 2006, SJCC and MMS entered into an agreement tolling the statute of limitations on any administrative action to recover unpaid royalties until BLM issued a final, non-appealable determination as to the proper rate for CHM-mined coal. The proposed BLM rulemaking has the potential to terminate the tolling provision of the settlement agreement, and underpaid royalties of approximately $5 million for SJGS would become due if the proposed BLM rule is adopted as proposed. PNM's share of any amount that is ultimately paid would be approximately 46.3%, none of which would be passed through PNM's FPPAC. PNM is unable to predict the outcome of this matter.

PVNGS Liability and Insurance Matters

Public liability for incidents at nuclear power plants is governed by the Price-Anderson Nuclear Industries Indemnity Act, which limits the liability of nuclear reactor owners to the amount of insurance available from both commercial sources and an industry-wide retrospective payment plan. In accordance with this act, the PVNGS participants are insured against public liability exposure for a nuclear incident up to $13.4 billion per occurrence. PVNGS maintains the maximum available nuclear liability insurance in the amount of $450 million, which is provided by American Nuclear Insurers. The remaining $13.0 billion is provided through a mandatory industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the program exceed the accumulated funds, PNM could be assessed retrospective premium adjustments. Based on PNM's 10.2% interest in each of the three PVNGS units, PNM's maximum potential retrospective premium assessment per incident for all three units is $38.9 million, with a maximum annual payment limitation of $5.8 million, to be adjusted periodically for inflation.

The PVNGS participants maintain insurance for damage to, and decontamination of, property at PVNGS in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. These coverages are provided by Nuclear Electric Insurance Limited ("NEIL"). The primary policy offered by NEIL contains a sublimit of $2.25 billion for non-nuclear property damage. If NEIL's losses in any policy year exceed accumulated funds, PNM is subject to retrospective premium adjustments of $5.4 million for each retrospective premium assessment declared by NEIL's Board of Directors due to losses. The insurance coverages discussed in this and the previous paragraph are subject to certain policy conditions, sublimits, and exclusions.

Natural Gas Supply

PNM procures gas supplies for its power plants from third-party sources and contracts with third party transportation providers.

Water Supply

Because of New Mexico's arid climate and periodic drought conditions, there is concern in New Mexico about the use of water, including that used for power generation.

Although PNM does not believe that its operations will be materially affected by drought conditions at this time, it cannot forecast long-term weather patterns. Public policy, local, state and federal regulations, and litigation regarding water could also impact PNM operations. To help mitigate these risks, PNM has secured permanent groundwater rights for the existing plants at Reeves Station, Rio Bravo, Afton, Luna, Lordsburg, and La Luz. Water availability is not an issue for these plants at this time. However, prolonged drought, ESA activities, and a federal lawsuit by the State of Texas (suing the State of New Mexico over water deliveries) could pose a threat of reduced water availability for these plants.

For SJGS and Four Corners, PNM and APS have negotiated an agreement with the more senior water rights holders (tribes, municipalities, and agricultural interests) in the San Juan basin to mutually share the impacts of water shortages with tribes and other water users in the San Juan basin. The agreement to share shortages in 2017 through 2020 has been negotiated and awaits endorsement by the parties and the New Mexico State Engineer.

In April 2010, APS signed an agreement on behalf of the PVNGS participants with five cities to provide cooling water essential to power production at PVNGS for 40 years.

PVNGS Water Supply Litigation

In 1986, an action commenced regarding the rights of APS and the other PVNGS participants to the use of groundwater and effluent at PVNGS. APS filed claims that dispute the court's jurisdiction over PVNGS' groundwater rights and their contractual rights to effluent relating to PVNGS and, alternatively, seek confirmation of those rights. In 1999, the Arizona Supreme Court issued a decision finding that certain groundwater rights may be available to the federal government and Indian tribes. In addition, the Arizona Supreme Court issued a decision in 2000 affirming the lower court's criteria for resolving groundwater claims. Litigation on these issues has continued in the trial court. No trial dates have been set in these matters. PNM does not expect that this litigation will have a material impact on its results of operation, financial position, or cash flows.

San Juan River Adjudication

In 1975, the State of New Mexico filed an action in New Mexico District Court to adjudicate all water rights in the San Juan River Stream System, including water used at Four Corners and SJGS. PNM was made a defendant in the litigation in 1976. In March 2009, then President Obama signed legislation confirming a 2005 settlement with the Navajo Nation. Under the terms of the settlement agreement, the Navajo Nation's water rights would be settled and finally determined by entry by the court of two proposed adjudication decrees. The court issued an order in August 2013 finding that no evidentiary hearing was warranted in the Navajo Nation proceeding and, on November 1, 2013, issued a Partial Final Judgment and Decree of the Water Rights of the Navajo Nation approving the proposed settlement with the Navajo Nation. Several parties filed a joint motion for a new trial, which was denied by the court. A number of parties subsequently appealed to the New Mexico Court of Appeals. PNM has entered its appearance in the appellate case. The issues have been fully briefed and the matter is pending with the New Mexico Court of Appeals. Adjudication of non-Indian water rights continues during the pendency of the appeal of the Navajo Nation settlement.

PNM is participating in this proceeding since PNM's water rights in the San Juan Basin may be affected by the rights recognized in the settlement agreement and adjudicated to the Navajo Nation, which comprise a significant portion of water available from sources on the San Juan River and in the San Juan Basin and which have priority in times of shortages. PNM is unable to predict the ultimate outcome of this matter or estimate the amount or range of potential loss and cannot determine the effect, if any, of any water rights adjudication on the present arrangements for water at SJGS and Four Corners. Final resolution of the case cannot be expected for several years. An agreement reached with the Navajo Nation in 1985, however, provides that if Four Corners loses a portion of its rights in the adjudication, the Navajo Nation will provide, for an agreed upon cost, sufficient water from its allocation to offset the loss.

Rights-of-Way Matter

On January 28, 2014, the County Commission of Bernalillo County, New Mexico passed an ordinance requiring utilities to enter into a use agreement and pay a yet-to-be-determined fee as a condition to installing, maintaining, and operating facilities on county rights-of-way. The fee is purported to compensate the county for costs of administering and maintaining the rights-of-way, as well as for capital improvements. On February 27, 2014, PNM and other utilities filed a Complaint for Declaratory and Injunctive Relief in the United States District Court for the District of New Mexico challenging the validity of the ordinance. The court denied the utilities' motion for judgment. The court further granted the County's motion to dismiss the state law claims. The utilities filed an amended complaint reflecting the two federal claims remaining before the federal court. The utilities also filed a complaint in Bernalillo County, New Mexico District Court reflecting the state law counts dismissed by the federal court. In subsequent briefing in federal court, the County filed a motion for judgment on one of the utilities' claims, which was granted by the court, leaving a claim regarding telecommunications service as the remaining federal claim. On January 4, 2016, the utilities filed an Application for Interlocutory Appeal from the state court, which was denied. On March 28, 2017, the utilities filed a *Writ of Certiorari* with the NM Supreme Court, which was denied. The matter will proceed in New Mexico District Court. The utilities and Bernalillo County reached a standstill agreement whereby the County would not take any enforcement action against the utilities pursuant to the ordinance during the pendency of the litigation, but not including any period for appeal of a judgment, or upon 30 days written notice by either the County or the utilities of their intention to terminate the agreement. If the challenges to the ordinance are unsuccessful, PNM believes any fees paid pursuant to the ordinance would be considered franchise fees and would be recoverable from customers. PNM is unable to predict the outcome of this matter or its impact on PNM's operations.

Complaint Against Southwestern Public Service Company

In September 2005, PNM filed a complaint under the Federal Power Act against SPS alleging SPS overcharged PNM for deliveries of energy through its fuel cost adjustment clause practices and that rates for sales to PNM were excessive. PNM also intervened in a similar proceeding brought by other SPS customers and a proceeding filed by SPS to revise its rates for sales to PNM. On October 29, 2015, FERC approved a settlement agreement resolving all outstanding issues between SPS and PNM. Under the settlement, SPS paid PNM $4.2 million. Of this amount, $2.6 million was passed back to PNM's customers through its FPPAC.

Navajo Nation Allottee Matters

A putative class action was filed against PNM and other utilities in February 2009 in the United States District Court for the District of New Mexico. Plaintiffs claim to be allottees, members of the Navajo Nation, who pursuant to the Dawes Act of 1887, were allotted ownership in land carved out of the Navajo Nation and allege that defendants, including PNM, are rights-of-way grantees with rights-of-way across the allotted lands and are either in trespass or have paid insufficient fees for the grant of rights-of-way or both. In March 2010, the court ordered that the entirety of the plaintiffs' case be dismissed. The court did not grant plaintiffs leave to amend their complaint, finding that they instead must pursue and exhaust their administrative remedies before seeking redress in federal court. In May 2010, plaintiffs filed a notice of appeal with the Bureau of Indian Affairs ("BIA"), which was denied by the BIA Regional Director. In May 2011, plaintiffs appealed the Regional Director's decision to the DOI, Office of Hearings and Appeals, Interior Board of Indian Appeals. Following briefing on the merits, on August 20, 2013, that board issued a decision upholding the Regional Director's decision that the allottees had failed to perfect their appeals, and dismissed the allottees' appeals, without prejudice. The allottees have not refiled their appeals. Although this matter was dismissed without prejudice, PNM considers the matter concluded. However, PNM continues to monitor this matter in order to preserve its interests regarding any PNM-acquired rights-of-way.

In a separate matter, in September 2012, 43 landowners claiming to be Navajo allottees filed a notice of appeal with the BIA appealing a March 2011 decision of the BIA Regional Director regarding renewal of a right-of-way for a PNM transmission line. The allottees, many of whom are also allottees in the above matter, generally allege that they were not paid fair market value for the right-of-way, that they were denied the opportunity to make a showing as to their view of fair market value, and thus denied due process. On January 6, 2014, PNM received notice that the BIA, Navajo Region, requested a review of an appraisal report on 58 allotment parcels. After review, the BIA concluded it would continue to rely on the values of the original appraisal. On March 27, 2014, while this matter was stayed, the allottees filed a motion to dismiss their appeal with prejudice. On April 2, 2014, the allottees' appeal was dismissed with prejudice. Subsequent to the dismissal, PNM received a letter from counsel on behalf of what appears to be a subset of the 43 landowner allottees involved in the appeal, notifying PNM that the specified allottees were revoking their consents for renewal of right of way on six specific allotments. On January 22, 2015, PNM received a letter from the BIA Regional Director identifying ten allotments with rights-of-way renewals that were previously contested. The letter indicated that the renewals were not approved by the BIA because the previous consent obtained by PNM was later revoked, prior to BIA approval, by the majority owners of the allotments. It is the BIA Regional Director's position that PNM must re-obtain consent from these landowners. On July 13, 2015, PNM filed a condemnation action in the NM District Court regarding the approximately 15.49 acres of land at issue. On December 1, 2015, the court ruled that PNM could not condemn two of the five allotments at issue based on the Navajo Nation's fractional interest in the land. PNM filed a motion for reconsideration of this ruling which was denied. On March 31, 2016, the Tenth Circuit granted PNM's petition to appeal the December 1, 2015 ruling. On September 18, 2015, the allottees filed a separate complaint against PNM for federal trespass. Both matters have been consolidated. On June 27, 2016, PNM filed its opening brief in the Tenth Circuit. *Amicus* briefs were filed in support of PNM's position. On October 5, 2016, the United States, the Navajo Nation, and individual allottees filed their response briefs. After the response briefs were filed, other entities requested leave to file *amicus* briefs addressing arguments raised in the United States' response brief. Oral argument before the Tenth Circuit was heard on January 17, 2017. On May 26, 2017, the Tenth Circuit affirmed the district court. On July 8, 2017, PNM filed a Motion for Reconsideration *en banc* with the Tenth Circuit. On July 21, 2017, the court denied PNM's Motion for Reconsideration. On July 26, 2017, PNM filed a motion to stay implementation of the court's decision, which was denied. On September 11, 2017, PNM filed an Application for Extension of Time to File a Petition for *Writ of Certiorari* in the US Supreme Court. PNM's application for an extension of time to November 20, 2017 was granted. The NM District Court has stayed the case until May 15, 2018 based on the Navajo Nation's acquisition of interests in two additional allotments and the unresolved ownership of the fifth allotment due to the owner's death. On November 20, 2017, PNM filed its Petition for *Writ of Certiorari* with the US Supreme Court. On December 22, 2017, *amicus* briefs supporting PNM's Petition for *Writ of Certiorari* were filed with the US Supreme Court. The US Supreme Court extended the United States' response period to March 23, 2018.

PNM cannot predict the outcome of these matters.

Sales Tax Audits

In November 2011, PNMR completed the sale of its retail electric provider, which operated in Texas under the name First Choice Power ("First Choice"). Under the sale agreement, PNMR is contractually obligated for First Choice's taxes relating to periods prior to the sale.

The Texas Comptroller of Public Accounts ("Comptroller") has initiated audits of First Choice's sales and use tax filings and miscellaneous gross receipts tax filings for periods prior to the sale. During the course of the audits, PNMR accrued an immaterial liability for items identified in the audits for which PNMR believed an unfavorable resolution was probable. The Comptroller has issued notifications of audit results indicating additional tax due of $5.0 million, plus penalties and interest. The primary issue in dispute is the disallowance by the auditor of the tax benefits of bad debt charge-offs and billing credits. On behalf of First Choice, PNMR filed requests for redetermination for both audits.

PNMR has engaged in continued discussions with the Comptroller, as well as supplying additional documentation in support of PNMR's positions. If PNMR and the Comptroller do not reach agreement, this matter will go to hearing with the Texas State Office of Administrative Hearings. Although PNMR believes its positions are correct, it is unable to predict the outcome of this matter.

(17) Regulatory and Rate Matters

The Company is involved in various regulatory matters, some of which contain contingencies that are subject to the same uncertainties as those described in Note 16.

PNM

New Mexico General Rate Cases

New Mexico 2015 General Rate Case ("NM 2015 Rate Case")

On December 11, 2014, PNM filed an application for revision of electric retail rates based upon a calendar year 2016 future test year ("FTY") period. The application proposed a revenue increase of $107.4 million, effective January 1, 2016. Several parties filed briefs, which alleged that PNM's application was incomplete and challenged other aspects of PNM's filing. On April 17, 2015, the Hearing Examiner in the case issued an Initial Recommended Decision to the NMPRC recommending that the NMPRC find PNM's application incomplete and reject it on the grounds that it did not comply with the FTY rule. The Hearing Examiner cited procedural defects in the filing, including a lack of fully functional electronic files and appropriate justification of certain costs in the future test year period. On May 13, 2015, the NMPRC voted to accept the Initial Recommended Decision regarding the completeness of PNM's application and dismissed PNM's application.

On August 27, 2015, PNM filed a new application with the NMPRC for a general increase in retail electric rates. The application proposed a revenue increase of $123.5 million, including base non-fuel revenues of $121.7 million. PNM's new application was based on a FTY period beginning October 1, 2015, which met the NMPRC's May 2015 interpretation of the FTY statute discussed below, and proposed a ROE of 10.5%. The primary drivers of PNM's identified revenue deficiency were the cost of infrastructure investments, including depreciation expense based on an updated depreciation study, and a decline in energy sales as a result of PNM's successful energy efficiency programs and economic factors. The new application included several proposed changes in rate design to establish fair and equitable pricing across rate classes and to better align cost recovery with cost causation. Specific rate

design proposals included higher customer and demand charges, a revenue decoupling pilot program applicable to residential and small commercial customers, a re-allocation of revenue among PNM's customer classes, a new economic development rate, and continuation of PNM's renewable energy rider. PNM requested that the proposed new rates become effective beginning in July 2016. On March 2, 2016, the NMPRC required PNM to file supplemental testimony regarding the treatment of renewable energy in PNM's FPPAC. See Renewable Portfolio Standard below. A public hearing on the proposed new rates was held in April 2016. Subsequent to this hearing, the NMPRC ordered PNM to file additional testimony regarding PNM's interests in PVNGS, including the 64.1 MW of PVNGS Unit 2 that PNM repurchased in January 2016, pursuant to the terms of the initial sales-leaseback transactions (Note 7). A subsequent public hearing was held in June 2016. After the June hearing, PNM and other parties were ordered to file supplemental briefs and to provide final recommended revenue requirements that incorporated fuel savings that PNM implemented effective January 1, 2016 from PNM's SJGS coal supply agreement ("SJGS CSA"). PNM's filing indicated that recovery for fuel related costs would be reduced by approximately $42.9 million reflecting the current SJGS CSA (Note 16), which also reduced the request for base non-fuel related revenues by $0.2 million to $121.5 million.

On August 4, 2016, the Hearing Examiner in the case issued a recommended decision (the "August 2016 RD"). The August 2016 RD proposed an increase in non-fuel revenues of $41.3 million compared to the $121.5 million increase requested by PNM. Major components of the difference in the increase in non-fuel revenues proposed in the August 2016 RD, included:

- A ROE of 9.575% compared to the 10.5% requested by PNM
- Disallowing recovery of the entire $163.3 million purchase price for the January 15, 2016 purchases of the assets underlying three leases of portions of PVNGS Unit 2 (Note 7); the August 2016 RD proposed that power from the previously leased assets, aggregating 64.1 MW of capacity, be dedicated to serving New Mexico retail customers with those customers being charged for the costs of fuel and operating and maintenance expenses (other than property taxes, which were $0.8 million per year at that time), but the customers would not bear any capital or depreciation costs other than those related to improvements made after the date of the original leases
- Disallowing recovery from retail customers of the rent expense, which aggregates $18.1 million per year, under the four leases of capacity in PVNGS Unit 1 that were extended for eight years beginning January 15, 2015 and the one lease of

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capacity in PVNGS Unit 2 that was extended for eight years beginning January 15, 2016 (Note 7) and related property taxes, which were $1.5 million per year at that time; the August 2016 RD proposed that power from the leased assets, aggregating 114.6 MW of capacity, be dedicated to serving New Mexico retail customers with those customers being charged for the costs of fuel and operating and maintenance expense, except that customers would not bear rental costs or property taxes

- Disallowing recovery of the costs of converting SJGS Units 1 and 4 to BDT, which is required by the NSR permit for SJGS, (Note 16); PNM's share of the costs of installing the BDT equipment was $52.3 million of which $40.0 million was included in rate base in PNM's rate request
- Disallowing recovery of $4.5 million of amounts recorded as regulatory assets and deferred charges

The August 2016 RD recommended that the NMPRC find PNM was imprudent in the actions taken to purchase the previously leased 64.1 MW of capacity in PVNGS Unit 2, extending the leases for 114.6 MW of capacity of PVNGS Units 1 and 2, and installing the BDT equipment on SJGS Units 1 and 4. The August 2016 RD also proposed that all fuel costs be removed from base rates and be recovered through the FPPAC. The August 2016 RD would credit retail customers with 100% of the New Mexico jurisdictional portion of revenues from "refined coal" (a third-party pre-treatment process) at SJGS. In addition, the August 2016 RD would remove recovery of the costs of power obtained from New Mexico Wind from the FPPAC and include recovery of those costs through PNM's renewable energy rider discussed below. The August 2016 RD recommended continuation of the renewable energy rider and certain aspects of PNM's proposals regarding rate design, but would not approve certain other rate design proposals or PNM's request for a revenue decoupling pilot program. The August 2016 RD proposed approving PNM's proposals for revised depreciation rates (except the August 2016 RD would require depreciation on Four Corners be calculated based on a 2041 life rather than the 2031 life proposed by PNM), the inclusion of construction work in progress in rate base, and ratemaking treatment of the "prepaid pension asset." The August 2016 RD did not preclude PNM from supporting the prudence of the PVNGS purchases and lease renewals in its next general rate case and seeking recovery of those costs. PNM disagreed with many of the key conclusions reached by the Hearing Examiner in the August 2016 RD and filed exceptions to defend its prudent utility investments. Other parties also filed exceptions to the August 2016 RD.

On September 28, 2016, the NMPRC issued an order that authorized PNM to implement an increase in non-fuel rates of $61.2 million, effective for bills sent to customers after September 30, 2016. The order generally approved the August 2016 RD, but with certain significant modifications. The modifications to the August 2016 RD included:

- Inclusion of the January 2016 purchase of the assets underlying three leases of capacity, aggregating 64.1 MW, of PVNGS Unit 2 at an initial rate base value of $83.7 million; and disallowance of the recovery of the undepreciated costs of capitalized improvements made during the period the 64.1 MW was being leased by PNM, which aggregated $43.8 million when the order was issued
- Full recovery of the rent expense and property taxes associated with the extended leases for capacity, aggregating 114.6 MW, in Palo Verde Units 1 and 2
- Disallowance of the recovery of any future contributions for PVNGS decommissioning costs related to the 64.1 MW of capacity purchased in January 2016 and the 114.6 MW of capacity under the extended leases
- Recovery of assumed operating and maintenance expense savings of $0.3 million annually related to BDT

On September 30, 2016, PNM filed a notice of appeal with the NM Supreme Court regarding the order in the NM 2015 Rate Case. Subsequently, NEE, NMIEC, and ABCWUA filed notices of cross-appeal to PNM's appeal. On October 26, 2016, PNM filed a statement of issues related to its appeal with the NM Supreme Court, which stated PNM is appealing the NMPRC's determination that PNM was imprudent in the actions taken to purchase the previously leased 64.1 MW of capacity in PVNGS Unit 2, extending the leases for 114.6 MW of capacity of PVNGS Units 1 and 2, and installing BDT equipment on SJGS Units 1 and 4. Specifically, PNM's statement indicated it is appealing the following elements of the NMPRC's order:

- Disallowance of recovery of the full purchase price, representing fair market value, of the 64.1 MW of capacity in PVNGS Unit 2 purchased in January 2016
- Disallowance of the recovery of the undepreciated costs of capitalized improvements made during the period the 64.1 MW of capacity was leased by PNM
- Disallowance of recovery of future contributions for PVNGS decommissioning attributable to the 64.1 MW of purchased capacity and the 114.6 MW of capacity under the extended leases
- Disallowance of recovery of the costs of converting SJGS Units 1 and 4 to BDT

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The issues that are being appealed by the various cross-appellants include:

- The NMPRC allowing PNM to recover the costs of the lease extensions for the 114.6 MW of PVNGS Units 1 and 2 and any of the purchase price for the 64.1 MW in PVNGS Unit 2
- The NMPRC allowing PNM to recover the costs incurred under the new coal supply contract for Four Corners
- The revised method to collect PNM's fuel and purchased power costs under the FPPAC
- The final rate design
- The NMPRC allowing PNM to include the "prepaid pension asset" in rate base

NEE subsequently filed a motion for a partial stay of the order at the NM Supreme Court. This motion was denied. The NM Supreme Court stated that the court's intent was to request that PNM reimburse ratepayers for any amount overcharged should the cross-appellants prevail on the merits.

On February 17, 2017, PNM filed its Brief in Chief, and pursuant to the court's rules, the briefing schedule was completed on July 21, 2017. Oral argument at the NM Supreme Court was held on October 30, 2017. Although appeals of regulatory actions of the NMPRC have a priority at the NM Supreme Court under New Mexico law, there is no required time frame for the court to act on the appeals.

GAAP requires that a loss is to be recognized when it is probable that a loss has been incurred and the amount of loss can be reasonably estimated. When there is a range of the amount of the probable loss, the minimum amount of the range is to be accrued unless an amount within the range is a better estimate than any other amount. As of September 30, 2016, PNM evaluated the accounting consequences of the order in the NM 2015 Rate Case and the likelihood of being successful on the issues it is appealing in the NM Supreme Court as required under GAAP. The evaluation indicated it is reasonably possible that PNM will be successful on the issues it is appealing. If the NM Supreme Court rules in PNM's favor on some or all of the issues, those issues would be remanded back to the NMPRC for further action. At that time, PNM estimated that it would take a minimum of 15 months, from the date PNM filed its appeal, for the NM Supreme Court to render a decision and for the NMPRC to take action on any remanded issues. During such time, the rates specified in the order would remain in effect. PNM concluded that a range of probable loss resulted from the NMPRC order in the NM 2015 Rate Case; that the minimum amount of loss was 15 months of capital cost recovery that the order disallowed for PNM's investments in the PVNGS Unit 2 purchases, PVNGS Unit 2 capitalized improvements, and BDT; and that no amount within the range of possible loss was a better estimate than any other amount. Accordingly, PNM recorded a pre-tax regulatory disallowance of $6.8 million at September 30, 2016 for the capital costs that will not be covered during that 15 month appeal period. In addition, PNM recorded a pre-tax regulatory disallowance for $4.5 million of costs recorded as regulatory assets and deferred charges (which the order disallowed and which PNM did not challenge in its appeal) since PNM could no longer assert that those assets were probable of being recovered through the ratemaking process.

The NMPRC's order approved PNM's request to record a regulatory asset to recover a 2014 impairment of PNM's New Mexico net operating loss carryforward resulting from an extension of the income tax provision for fifty percent bonus depreciation. The impact, net of federal income taxes, amounting to $2.1 million was reflected as a reduction of income tax expense on the Consolidated Statement of Earnings.

PNM also evaluated the accounting consequences of the issues that are being appealed by the cross-appellants. PNM does not believe the issues raised in the cross-appeals have substantial merit. Accordingly, PNM does not believe that the likelihood of the cross-appeals being successful is probable and, therefore, no loss was recorded in 2016 related to the issues subject to the cross-appeals.

Since the NM Supreme Court did not issue a decision on the appeals related to the NM 2015 Rate Case by December 31, 2017, which was 15 months from the date of the NMPRC's order in that case, PNM has reevaluated the accounting consequences of the order in the NM 2015 Rate Case. PNM continues to believe that it is reasonably possible that PNM will be successful on the issues it is appealing and that it is not probable the cross appeals will be successful. However, based on the proceedings to date in the appeal process and other actions by the NM Supreme Court, PNM now estimates that it will take an additional seven months from December 31, 2017 for the NM Supreme Court to issue a decision and any remanded issues to be addressed by the NMPRC. Accordingly, PNM recorded an additional loss of $3.1 million at December 31, 2017, representing an additional disallowance of seven months of capital cost recovery that the order disallowed. Further losses will be recorded if the currently

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estimated time frame for the NM Supreme Court to render a decision and for the NMPRC to take action on any remanded issues in extended.

PNM continues to believe that the disallowed investments, which are the subject of PNM's appeal, were prudent and that PNM is entitled to full recovery of those investments through the ratemaking process. Although PNM believes it is reasonably possible that its appeals will be successful, it cannot predict what decision the NM Supreme Court will reach or what further actions the NMPRC will take on any issues remanded to it by the court. If PNM's appeal is unsuccessful, PNM would record further pre-tax losses related to the capitalized costs for any unsuccessful issues. The impacts of not recovering future contributions for decommissioning would be recognized in future periods reflecting that rates charged to customers would not recover those costs as they are incurred. The amounts of any such losses to be recorded would depend on the ultimate outcome of the appeal and NMPRC process, as well as the actual amounts reflected on PNM books at the time of the resolution. However, based on the book values recorded by PNM as of December 31, 2017, such losses could include:

- The remaining costs to acquire the assets previously leased under three leases aggregating 64.1 MW of PVNGS Unit 2 capacity in excess of the recovery permitted under the NMPRC's order; the net book value of such excess amount was $75.3 million, after considering the loss recorded in 2016 and 2017
- The undepreciated costs of capitalized improvements made during the period the 64.1 MW of capacity in PVNGS Unit 2 purchased by PNM in January 2016 was being leased by PNM; the net book value of these improvements was $39.1 million, after considering the loss recorded in 2016 and 2017
- The remaining costs to convert SJGS Units 1 and 4 to BDT; the net book value of these assets was $49.4 million, after considering the loss recorded in 2016 and 2017

Although PNM does not believe that the likelihood of the cross-appeals being successful is probable, it is unable to predict what decision the NM Supreme Court will reach. If the NM Supreme Court were to overturn all of the issues subject to the cross-appeals and, upon remand, the NMPRC did not provide any cost recovery of those items, PNM would write-off all of the costs to acquire the assets previously leased under three leases, aggregating 64.1 MW of PVNGS Unit 2 capacity, totaling $151.1 million (which amount includes $75.3 million that is the subject of PNM's appeal discussed above) at December 31, 2017, after considering the loss recorded in 2016 and 2017. The impacts of not recovering costs for the lease

extensions, new coal supply contract for Four Corners, and "prepaid pension asset" in rate base would be recognized in future periods reflecting that rates charged to customers would not recover those costs as they are incurred. The outcomes of the cross-appeals regarding the FPPAC and rate design should not have a financial impact to PNM.

PNM is unable to predict the outcome of this matter.

New Mexico 2016 General Rate Case ("NM 2016 Rate Case")

On December 7, 2016, PNM filed an application with the NMPRC for a general increase in retail electric rates. PNM did not include any of the costs disallowed in the NM 2015 Rate Case that are at issue in its pending appeal to the NM Supreme Court. Key aspects of PNM's request were:

- An increase in base non-fuel revenues of $99.2 million
- Based on a FTY beginning January 1, 2018 (the NMPRC's rules specify that a FTY is a 12 month period beginning up to 13 months after the filing of a rate case application)
- ROE of 10.125%
- Drivers of revenue deficiency
  - Implementation of the modifications in PNM's resource portfolio, which were previously approved by the NMPRC as part of the SJGS regional haze compliance plan (Note 16)
  - Infrastructure investments, including environmental upgrades at Four Corners
  - Declines in forecasted energy sales due to successful energy efficiency programs and other economic factors
  - Updates in the FERC/retail jurisdictional allocations
- Proposed changes to rate design to establish fair and equitable pricing across rate classes and to better align cost recovery with cost causation
  - Increased customer and demand charges

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  - A "lost contribution to fixed cost" mechanism applicable to residential and small commercial customers to address the regulatory disincentive associated with PNM's energy efficiency programs

The NMPRC scheduled a public hearing to begin on June 5, 2017, ordered that a settlement conference should be held, and that any resulting stipulation should be filed by March 27, 2017. Settlement discussions were held, but no agreements were reached by March 27, 2017, after which the date for filing a stipulation was extended. In early May 2017, PNM and thirteen intervenors (the "Signatories") entered into a comprehensive stipulation. On May 12, 2017, the Hearing Examiners issued an order rejecting the stipulation in its then current form, but allowed the Signatories to revise the stipulation. On May 23, 2017, the Signatories filed a revised stipulation that addressed the issues raised by the Hearing Examiners in their order. NEE was the sole party opposing the revised stipulation. The terms of the revised stipulation, which required NMPRC approval in order to take effect, included:

- A revenue increase totaling $62.3 million, with an initial increase of $32.3 million beginning January 1, 2018 and the remaining increase beginning January 1, 2019
- A ROE of 9.575%
- Full recovery of PNM's investment in SCRs at Four Corners with a debt-only return
- An agreement not to adjust non-fuel base rate changes to be effective prior to January 1, 2020
- An agreement to adjust the January 2019 increase for certain changes in federal corporate tax laws enacted prior to November 1, 2018 and effective and applicable to PNM by January 1, 2019 and to true-up PNM's cost of debt for refinancing transactions through 2018
- Returning to customers over a three-year period the benefit of the reduction in the New Mexico corporate income tax rate (Note 11) to the extent attributable to PNM's retail operations
- PNM would withdraw its proposal for a "lost contribution to fixed cost" mechanism with the issue to be addressed in a future docket
- PNM would perform a cost benefit analysis in its 2020 IRP of the impact of a possible early exit from Four Corners in 2024 and 2028

A hearing on the revised stipulation was held in August 2017. On October 31, 2017, the Hearing Examiners issued a Certification of Stipulation recommending a Modified Revised Stipulation. The significant changes to the revised stipulation in the Hearing Examiners' Modified Revised Stipulation included:

- Identifying PNM's decision to continue its participation in Four Corners as imprudent
- Disallowing PNM's ability to collect a debt or equity return on its $90.1 million investment in SCRs at Four Corners and on $58.0 million of projected capital improvements during the period July 1, 2016 through December 31, 2018
- Recommending a temporary disallowance of $36.8 million of PNM's projected capital improvements at SJGS through December 31, 2018

On December 20, 2017, the NMPRC issued an Order Partially Adopting Certification of Stipulation, which approved the Hearing Examiners' Certification of Stipulation with certain changes. Substantive changes from the Certification of Stipulation included requiring the impacts of changes related to the reduction in the federal corporate income tax rate be implemented effective January 1, 2018 rather than January 1, 2019 and deferring further consideration regarding the prudency of PNM's decision to continue its participation in Four Corners to a future proceeding.

On December 28, 2017 PNM filed a Motion for Rehearing and Request for Oral Argument asking the NMPRC to vacate their December 20, 2017 order and allow the parties to present oral argument. Additionally, several signatories to the revised stipulation filed a Joint Motion for Partial Rehearing asking that the NMPRC approve the Revised Stipulation without modification. On January 2, 2018, NEE filed a response urging the NMPRC to reject PNM's Motion.

On January 3, 2018, the NMPRC vacated its December 20, 2017 order and granted the motions for rehearing. The rehearing was held on January 10, 2017.

The NMPRC issued a Revised Order Partially Adopting Certification of Stipulation dated January 10, 2018 (the "Revised Order"). The Revised Order approved the Hearing Examiners' Certification of Stipulation with certain changes including:

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- Requiring the impacts of changes related to the reduction in the federal corporate income tax rate and PNM's cost of debt be implemented in 2018 rather than January 1, 2019
- Deferring further consideration regarding the prudency of PNM's decision to continue its participation in Four Corners to PNM's next rate case
- Disallowing PNM's ability to collect an equity return on its $90.1 million investment in SCRs at Four Corners and on $58.0 million of projected capital improvements during the period July 1, 2016 through December 31, 2018, but allowed recovery of the total $148.1 million of investments with a debt-only return
- Requiring PNM to reduce the requested $62.3 million increase in non-fuel revenue by $9.1 million
- Implementation of the first phase of the rate increase for services rendered, rather than bills rendered, on or after February 1, 2018 and of the second for services rendered on or after January 1, 2019

On January 16, 2018, PNM requested clarifying changes to the Revised Order to adjust the $9.1 million reduction to $4.4 million, asserting that $4.7 million of the reduction was duplicative. On January 17, 2018, the NMPRC issued an order approving the adjustment requested by PNM. On January 19, 2018, PNM and the Signatories filed a Joint Notice of All Signatories of Acceptance of the Order on Notice of Acceptance. On January 31, 2018, the NMPRC issued an order closing the docket in the NM 2016 Rate Case. After implementation of changes to the federal corporate income tax rate and cost of debt, the final order results in a net increase to PNM's non-fuel revenue requirement of $10.3 million. PNM implemented 50% of the approved increase for service rendered on or after February 1, 2018 and will implement the rest of the increase for service rendered on or after January 1, 2019.

GAAP requires PNM to recognize a loss to reflect that PNM will not earn an equity return on $148.1 million of investments at Four Corners. As of December 31, 2017, PNM recorded a pre-tax regulatory disallowance of $27.9 million. The amount of the loss was calculated by determining the present value of disallowed cash flows, which equals the difference between the cash flows resulting from recovery of those investments at PNM's embedded cost of debt and the cash flows with a full return on investment (including an equity component), and discounting the differences at PNM's WACC.

On February 7, 2018, NEE filed a notice of appeal with the NM Supreme Court asking the court to review the NMPRC's decisions in the NM 2016 Rate Case. The notice does not set forth the basis of the appeal, which, as required by the court's rules, is to be filed by March 9, 2018. PNM cannot predict the outcome of this matter.

Proceeding Regarding Definition of Future Test Year

On May 27, 2015, the NMPRC approved an order that defines a FTY as a period that begins no later than 45 days following the filing of an application to increase rates. PNM disagreed with the interpretation adopted by the NMPRC and believes that the correct interpretation of the New Mexico FTY statute allows a FTY to begin up to 13 months after the filing of an application.

On June 25, 2015, PNM filed a notice of appeal to the NM Supreme Court, challenging the NMPRC's June 3, 2015 written order. On July 31, 2015, PNM and the NMPRC filed a joint motion for a temporary 30-day stay and remand of PNM's appeal so that the NMPRC could reconsider its FTY order in PNM's 2014 rate case. The NM Supreme Court remanded this matter back to the NMPRC. On November 30, 2015, the NMPRC modified its previous order to provide for a FTY to begin up to 13 months after the filing of a rate case application. PNM and the NMPRC filed for dismissal of the appeal and the NM Supreme Court dismissed the appeal on February 15, 2016.

Investigation/Rulemaking Concerning NMPRC Ratemaking Policies

On March 22, 2017, the NMPRC issued an order opening an investigation and rulemaking to simplify and increase "the transparency of NMPRC rate cases by reducing the number of issues litigated in rate cases," and provide a "more level playing field among intervenors and NMPRC staff on the one hand, and the utilities on the other." The order posed the following questions: whether a standardized method should be established for determining ROE; should the ROE be subject to reward or penalty based on utilities meeting or failing to meet certain metrics, which could include customer complaints, outages, peak demand reductions, and RPS and energy efficiency compliance; whether recovery of utility rate case expenses should be limited to 50% unless the case is settled; whether intervenors should be allowed to recover their expenses if the NMPRC accepts their position; whether parties should have access to software used by utilities to support their positions; and how regulatory assets should be authorized

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and recovered. Initial comments were filed in July 2017 and several public workshops have been held. PNM cannot predict the outcome of this proceeding.

Renewable Portfolio Standard

The REA establishes a mandatory RPS requiring a utility to acquire a renewable energy portfolio equal to 10% of retail electric sales by 2011, 15% by 2015, and 20% by 2020. PNM files annual renewable energy procurement plans for approval by the NMPRC. The NMPRC requires renewable energy portfolios to be "fully diversified." The current diversity requirements, which are subject to the limitation of the RCT, are minimums of 30% wind, 20% solar, 3% distributed generation, and 5% other.

The REA provides for streamlined proceedings for approval of utilities' renewable energy procurement plans, assures that utilities recover costs incurred consistent with approved procurement plans, and requires the NMPRC to establish a RCT for the procurement of renewable resources to prevent excessive costs being added to rates. Currently, the RCT is set at 3% of customers' annual electric charges. PNM makes renewable procurements consistent with the NMPRC approved plans. PNM recovers certain renewable procurement costs from customers through a rate rider. See Renewable Energy Rider below.

Included in PNM's approved procurement plans are the following renewable energy resources:

- 107 MW of PNM-owned solar PV facilities, including 40 MW constructed in 2015 that were identified as a cost-effective resource in PNM's application to retire SJGS Units 2 and 3 (Note 16) and are being recovered in the base rates provided in the NM 2015 Rate Case discussed above rather than through PNM's renewable energy rider; and an additional procurement of 1.5 MW of PNM-owned solar PV facilities to supply the energy sold under PNM's voluntary renewable energy tariff
- A PPA through 2044 for the output of New Mexico Wind, having a current aggregate capacity of 204 MW and a PPA through 2035 for the output of Red Mesa Wind, an existing wind generator having an aggregate capacity of 102 MW
- A PPA through 2042 for the output of the Lightning Dock Geothermal facility; the geothermal facility began providing power to PNM in January 2014; the current capacity of the facility is 4 MW

- Solar distributed generation, aggregating 81.6 MW at December 31, 2017, owned by customers or third parties from whom PNM purchases any net excess output and RECs
- Solar and wind RECs as needed to meet the RPS requirements

PNM filed its 2016 renewable energy procurement plan on June 1, 2015. The plan met RPS and diversity requirements within the RCT in 2016 and 2017 using existing resources and did not propose any significant new procurements. The NMPRC approved the plan in November 2015, and, after granting a rehearing motion to consider issues regarding the rate treatment of certain customers eligible for a cap on, or an exemption from, RPS procurement, the NMPRC again approved the plan in an order issued on February 3, 2016. The NMPRC deferred issues related to capped and exempt customers to PNM's NM 2015 Rate Case and to a new case, which the NMPRC subsequently initiated through issuance of an order to show cause. The NM 2015 Rate Case and show cause proceeding were to examine whether PNM miscalculated the FPPAC factor and base fuel costs in its treatment of renewable energy costs and application of the renewable procurement cost caps and exemptions. The show cause proceeding was stayed pending the outcome of the NM 2015 Rate Case. The September 28, 2016 order in the NM 2015 Rate Case directed that the cost of New Mexico Wind be recovered through PNM's renewable rider, rather than the FPPAC, and ordered certain other modifications regarding the accounting for renewable energy in PNM's FPPAC. These modifications do not affect the amount of fuel and purchased power or renewable costs that PNM will collect. No action has been taken in the show cause proceeding and PNM cannot predict its outcome.

PNM filed its 2017 renewable energy procurement plan on June 1, 2016. The plan met RPS and diversity requirements for 2017 and 2018 using existing resources and PNM did not propose any significant new procurements. PNM projected that its plan would slightly exceed the RCT in 2017 and would be within the RCT in 2018. PNM requested a variance from the RCT in 2017 to the extent the NMPRC determined a variance was necessary. A public hearing was held on September 26, 2016. On October 21, 2016, the Hearing Examiner issued a recommended decision recommending that the plan be approved as filed and also found that a variance from the RCT was not required. The NMPRC approved the recommended decision on November 23, 2016.

On June 1, 2017, PNM filed its 2018 renewable energy procurement plan. PNM requested approval to procure an additional 80 GWh in 2019 and 105 GWh in 2020 from a re-powering of New Mexico Wind; approval to procure an additional 55 GWh in

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2019 and 77 GWh in 2020 from a re-powering of Lightning Dock Geothermal; approval to procure 50 MW of new solar facilities to be constructed beginning in 2018, and continuation of customer REC purchase programs and other purchases of RECs to ensure annual compliance with the RPS. PNM's proposed procurement cost for 2018 and 2019 will be within the RCT. The plan also sought a variance from the "other" diversity category in 2018 due to a revised production forecast of the Lightning Dock Geothermal facility in 2018. PNM also requested to adjust its annual renewable energy rate rider to collect the costs of renewable resources. A public hearing on the application was held in September 2017. On October 17, 2017, the Hearing Examiner issued a recommended decision that PNM's 2018 renewable energy procurement plan be approved by the NMPRC, except for the re-powering of Lightning Dock Geothermal and PNM's request to procure 50 MW of new solar facilities. The Hearing Examiner recommended that the PPA for the output of energy from Lightning Dock Geothermal be terminated effective January 1, 2018. The Hearing Examiner also recommended that PNM be required to issue another all-renewables RFP allowing developers to utilize PNM-owned sites to construct facilities, the output from which facilities would be sold to PNM through PPAs. PNM strongly disagreed with the Hearing Examiner's recommendations and filed exceptions contesting the Hearing Examiner's proposals. On November 15, 2017, the NMPRC issued an order approving PNM's plan and rejecting the Hearing Examiner's recommendations. On November 29, 2017, NMIEC filed an appeal with the NM Supreme Court objecting to the fuel allocation methodology. On December 14, 2017, NEE filed a motion to intervene and cross-appeal objecting to the approval of the 50 MW of new solar facilities. On December 18, 2017, PNM filed a motion to intervene, which was granted. NMIEC filed a motion for a partial stay of the NMPRC order and PNM filed a response opposing the request. On February 27, 2018, the court issued an order denying the motion for stay. A briefing schedule has not been determined. PNM cannot predict the outcome of this matter.

Renewable Energy Rider

The NMPRC has authorized PNM to recover certain renewable procurement costs through a rate rider billed on a per KWh basis. In PNM's NM 2015 Rate Case, the NMPRC authorized continuation of the renewable rider. PNM recorded revenues from the rider of $45.2 million, $42.0 million, and $41.9 million in 2017, 2016, and 2015. Beginning in 2017, the costs of energy from New Mexico Wind is being recovered through the rider, rather than through the FPPAC, in compliance with the NMPRC's order in PNM's NM 2015 Rate Case. In its 2018 renewable energy procurement plan case, PNM proposed to collect $43.5 million. The 2018 renewable energy procurement plan became effective on January 1, 2018.

Under the renewable rider, if PNM's earned rate of return on jurisdictional equity in a calendar year, adjusted for weather and other items not representative of normal operations, exceeds the NMPRC-approved rate by 0.5%, PNM is required to refund the excess to customers during May through December of the following year. PNM's annual compliance filings with the NMPRC show that its rate of return on jurisdictional equity did not exceed the limitation through 2016. Preliminary calculations indicate PNM did not exceed such limitation in 2017.

Energy Efficiency and Load Management

Program Costs and Incentives/Disincentives

The New Mexico Efficient Use of Energy Act ("EUEA") requires public utilities to achieve specified levels of energy savings and to obtain NMPRC approval to implement energy efficiency and load management programs. The EUEA requires the NMPRC to remove utility disincentives to implementing energy efficiency and load management programs and to provide incentives for such programs. The NMPRC has adopted a rule to implement this act. The EUEA sets an annual program budget equal to 3% of an electric utility's annual revenue. PNM's costs to implement approved programs are recovered through a rate rider.

On October 6, 2014, PNM filed an energy efficiency program application for programs proposed to be offered beginning in June 2015. The filing included proposed program costs of $25.8 million plus a proposed profit incentive. The proposed energy efficiency budget and plan are consistent with the 2013 amendments to the EUEA. PNM and the NMPRC staff filed a stipulated settlement on January 30, 2015. After a public hearing, the NMPRC approved the settlement on April 29, 2015. The approval established program budgets and the incentive amounts.

On April 15, 2016, PNM filed an application for energy efficiency and load management programs to be offered in 2017. The proposed program portfolio consisted of ten programs with a total budget of $28.0 million. The application also sought approval of an incentive of $2.4 million based on targeted savings of 75 GWh. The actual incentive would be based on actual savings achieved. On January 11, 2017, the NMPRC approved an unopposed stipulation that established a method to ensure that

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funding of PNM's energy efficiency program is equal to 3% of retail revenues, with an estimated 2017 energy efficiency funding level of $26.0 million, and approved a sliding scale profit incentive with a base level of 7.1% of program costs, equal to $1.8 million, if PNM achieves a minimum proscribed level of energy savings, increasing to a maximum of 9.0% depending on actual energy savings achieved above the minimum. PNM's preliminary estimate of the incentive earned in 2017 is $2.1 million, which is subject to verification by an independent evaluator.

On April 14, 2017, PNM filed an application for energy efficiency and load management programs to be offered in 2018. The proposed program portfolio consists of a continuation of the ten programs approved in the 2016 application with a total budget of $25.1 million. The application also sought approval of a sliding scale incentive with a base incentive of $1.9 million if PNM is able to achieve savings of 53 GWh in 2018. As proposed, PNM would have earned an incentive of $2.1 million based on targeted savings of 70 GWh. The actual incentive would be based on actual savings achieved. PNM proposed to continue the same ten programs and a similar incentive mechanism in 2019, with a proposed budget of $28.2 million and a base level incentive of $2.1 million. On July 26, 2017, PNM, NMPRC staff, and other parties filed a stipulation that would resolve all issues in the case if approved by the NMPRC. Under the settlement, all of PNM's proposed programs would be approved with limited modifications and PNM's base level incentive would be $1.7 million in 2018. PNM would earn an incentive of $1.9 million based on targeted savings of 69 GWh. A public hearing was held in September 2017. On November 8, 2017, the Hearing Examiner issued a Certification of Stipulation recommending approval of the stipulation with various modifications, including adoption of a discount rate equal to the tax-adjusted WACC of 9.59% rather than the 7.71% proposed in the stipulation and modifying the program budgets to $23.6 million for 2018 and $24.9 million for 2019. On January 31, 2018, the NMPRC issued an order that largely accepts the certification with certain exceptions concerning the measurement and verification of the approved load management programs.

Energy Efficiency Rulemaking

In July 2012, the NMPRC opened an energy efficiency rulemaking docket to potentially address decoupling and incentives. Workshops to develop a proposed rule have been held, but no order proposing a rule has been issued. PNM is unable to predict the outcome of this matter.

On January 25, 2017, the NMPRC opened another energy efficiency rulemaking docket to consider whether applications for approval of energy efficiency and load management programs should be filed every two years rather than annually. On June 21, 2017, the NMPRC issued an order that modifies the filing frequency for utility energy efficiency plans to every three years. Also on June 21, 2017, the NMPRC issued a new notice of proposed rulemaking to consider possible changes affecting a utility's ability to modify NMPRC approved funding levels by up to 10% between energy efficiency program applications. This rulemaking is in response to consensus changes proposed by parties in the January 25, 2017 rulemaking. On September 13, 2017, the NMPRC approved the proposed rule. Under the new rule, PNM's next application for energy efficiency and load management programs will be made in 2020 for programs to be offered beginning in 2021.

Integrated Resource Plans

NMPRC rules require that investor owned utilities file an IRP every three years. The IRP is required to cover a 20-year planning period and contain an action plan covering the first four years of that period.

2014 IRP

PNM filed its 2014 IRP on July 1, 2014. The four-year action plan was consistent with the replacement resources identified in PNM's application to retire SJGS Units 2 and 3. PNM indicated that it planned to meet its anticipated long-term resource needs with a combination of additional renewable energy resources, energy efficiency, and natural gas-fired facilities. Consistent with statute and NMPRC rule, PNM incorporated a public advisory process into the development of its 2014 IRP. On July 31, 2014, several parties requested the NMPRC to not accept the 2014 IRP as compliant with NMPRC rule because to do so could affect the then pending proceeding on PNM's application to abandon SJGS Units 2 and 3 and for CCNs for certain replacement resources (Note 16) and because they asserted that the 2014 IRP did not conform to the NMPRC's IRP rule. Certain parties also asked that further proceedings on the 2014 IRP be held in abeyance until the conclusion of the SJGS abandonment/CCN proceeding. The NMPRC issued an order in August 2014 that docketed a case to determine whether the 2014 IRP complied with applicable NMPRC rules. The order also held the case in abeyance pending the issuance of final, non-appealable orders in PNM's 2015 renewable energy procurement plan case and its application to retire SJGS Units 2 and 3. The order regarding PNM's application to abandon SJGS Units 2 and 3 described in Note 16 states that the NMPRC will issue a Notice of Proposed Dismissal in the 2014 IRP docket.

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On May 4, 2016, the NMPRC issued the Notice of Proposed Dismissal, stating that the docket would be closed with prejudice within thirty days unless good cause was shown why the docket should remain open. On May 31, 2016, NEE filed a request to hold the protests filed against PNM's 2014 IRP in abeyance or to dismiss those protests without prejudice. PNM responded on June 13, 2016 and requested that the NMPRC dismiss the case with prejudice. The NMPRC has not yet acted on its Notice of Proposed Dismissal or the request filed on May 31, 2016. PNM cannot predict the outcome of this matter.

2017 IRP

PNM filed its 2017 IRP on July 3, 2017. The 2017 IRP addresses a 20-year planning period, from 2017 through 2036, and includes an action plan describing PNM's plan to implement the 2017 IRP in the four-year period following its filing. PNM held its initial public advisory meeting on the 2017 IRP on June 30, 2016 and hosted 17 meetings statewide to present details of the process and receive public comment. The NMPRC's order concerning SJGS' compliance with the BART requirements of the CAA discussed in Note 16 requires PNM to make a filing in 2018 to determine the extent to which SJGS Units 1 and 4 should continue serving PNM's retail customers' needs after June 30, 2022. The 2017 IRP analyzed several scenarios utilizing assumptions that PNM continues service from its SJGS capacity beyond mid-2022 and that PNM retires its capacity after mid-2022. Key findings of the 2017 IRP include:

- Retiring PNM's share of SJGS in 2022 after the expiration of the current operating and coal supply agreements would provide long-term cost savings for PNM's customers
- PNM exiting its ownership interest in Four Corners after its current coal supply agreement expires in 2031 would also save customers money
- The best mix of new resources to replace the retired coal generation would include solar energy and flexible natural gas-fired peaking capacity; the mix could include energy storage, if the economics support it, and wind energy, provided additional transmission capacity becomes available
- Significant increases in future wind energy supplies will likely require new transmission capacity to be built from eastern New Mexico to PNM's service territory
- PNM should retain the currently leased capacity in PVNGS, which would avoid replacement with carbon-emitting generation

- PNM should continue to develop and implement energy efficiency and demand management programs
- PNM should assess the costs and benefits of participating in the California Energy Imbalance Market
- PNM should analyze its current Reeves Generating Station to consider possible technology improvements to phase out the older generators and replace them with new, more flexible supplies or energy storage

Protests to the 2017 IRP were filed by several parties. The issues addressed in the protests included the future of PNM's interests in SJGS, Four Corners, and PVNGS and the timing of future procurement of renewable resources. The NMPRC has assigned the case to a Hearing Examiner. On January 16, 2018, the Hearing Examiner issued an order setting the scope of the proceedings as the 2017 IRP's compliance with applicable statute and NMPRC rules. PNM is required to provide certain underlying information and clarify how costs, transmission constraints, energy storage, and public input were considered in developing the 2017 IRP. A pre-hearing conference was held on January 26, 2018 and hearings are scheduled to begin on June 4, 2018.

The 2017 IRP is not a final determination of PNM's future generation portfolio. Retiring PNM's share of SJGS capacity and exiting Four Corners would require NMPRC approval of abandonment filings, which PNM would make at appropriate times in the future. Likewise, NMPRC approval of new generation resources through CCN filings would be required. PNM cannot predict the ultimate outcome of the 2017 IRP process or whether the NMPRC will approve subsequent filings that would encompass actions to implement the conclusions of the 2017 IRP.

San Juan Generating Station Units 2 and 3 Retirement

On December 16, 2015, the NMPRC issued an order approving PNM's retirement of SJGS Units 2 and 3 on December 31, 2017. On January 14, 2016, NEE filed an appeal of the order with the NM Supreme Court. SJGS Units 2 and 3 were retired in December 2017. Additional information concerning the NMPRC filing and related proceedings is set forth in Note 16.

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Application for Certificate of Convenience and Necessity

On June 30, 2015, PNM filed an application for a CCN for a 187 MW gas plant to be located at SJGS. This resource was identified as a replacement resource in PNM's application to retire SJGS Units 2 and 3. On February 12, 2016, PNM filed a motion to withdraw its application. On May 18, 2016, the NMPRC issued an order granting PNM's request to withdraw the application and closing the case.

On April 26, 2016, PNM filed an application for an 80 MW gas plant to be located at SJGS, with an anticipated June 2018 in-service date. On October 13, 2016, PNM filed a motion to vacate the procedural schedule to allow PNM to assess the continued need for the plant in light of possible changed circumstances affecting loads and resources. On October 28, 2016, PNM filed a motion to withdraw its application and close the docket. As grounds for the motion, PNM stated that, based on its updated peak demand forecast, the 80 MW plant would not be needed in 2018. On December 1, 2016, the Hearing Examiner issued a recommended decision that would grant PNM's motion to withdraw its application. On May 24, 2017, the NMPRC issued its order approving the recommended decision and granting the motion to withdraw the application. PNM will continue to evaluate its resource needs as part of its ongoing resource planning activities.

Advanced Metering Infrastructure Application

On February 26, 2016, PNM filed an application with the NMPRC requesting approval of a project to replace its existing customer metering equipment with Advanced Metering Infrastructure ("AMI"). The application asks the NMPRC to authorize the recovery of the cost of the project, up to $87.2 million, in future ratemaking proceedings, as well as to approve the recovery of the remaining undepreciated investment in existing metering equipment estimated to be approximately $33 million at the date of implementation and the costs of customer education and severances for affected employees. Hearings in this matter were held in February and March 2017. During the March 2017 hearing, it was disclosed that the proposed meter contractor may not have complied with certain New Mexico contractor licensing requirements. PNM subsequently filed testimony regarding that matter as ordered by the Hearing Examiner. On May 12, 2017, PNM requested a new procedural schedule to allow it to issue a new RFP for contracting work related to the meter installation and to update its cost-benefit analysis. PNM subsequently updated the amount of the requested recovery for the anticipated cost of the project to $95.1 million. An additional hearing was held on October 25-26, 2017. PNM does not intend to proceed with the AMI project unless the NMPRC approves the entire application. PNM cannot predict the outcome of this matter.

Facebook, Inc. Data Center Project

On July 8, 2016, PNM filed an application with the NMPRC for approval of:

- Two new electric service rates
- A PPA under which PNM would purchase renewable energy from PNMR Development
- A special service contract to provide electric service to a prospective new customer, a large Internet company, that was considering locating a data center in PNM's service area

The NMPRC approved PNM's application on August 17, 2016. At that time, the new customer was also considering the state of Utah for the location of the data center. On September 15, 2016, PNM filed a notice informing the NMPRC that the customer, Facebook, Inc., had announced that it was selecting a site in New Mexico for its new data center.

Facebook's service requirements include the acquisition by PNM of a sufficient amount of new renewable energy resources and RECs to match the energy and capacity requirements of the data center. PNM's initial procurement was to be through a PPA with PNMR Development for the energy production from 30 MW of new solar capacity that PNMR Development was constructing. As discussed in Note 1, PNMR Development transferred its interests in the solar capacity and the PPA to NMRD in December 2017. The cost of the PPA is to be passed through to Facebook under a new rate rider. A new special service rate will be applied to Facebook's energy consumption in those hours of the month when their consumption exceeds the energy production from the new renewable resources. The first 10 MW of solar capacity began commercial operation on January 1, 2018, which coincides with initial operations of the data center, and the remainder of the capacity is anticipated to be completed by mid-2018.

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The approval order included a provision requiring that in any future rate case filed by PNM requesting an increase in rates of any other customer class, the NMPRC shall determine whether or not any customer class will be subject to increased rates due to Facebook's fixed "Contribution to Production Charge for System Supplied Energy" and, if so, the NMPRC shall determine whether or not PNM will be allowed to recover such increased costs in the form of increased rates to other customers. In the NM 2016 Rate Case filing discussed above, PNM indicated the Facebook arrangement did not result in increased rates to any other customer class.

In late 2017, PNM entered into three separate 25-year PPAs to purchase renewable energy and RECs to be used by PNM to supply additional renewable power to Facebook. These PPAs are subject to NMPRC approval and PNM made a filing requesting approval on January 17, 2018. A NMPRC hearing on PNM's filing is scheduled for March 7, 2018. These PPAs include the purchase of the power and RECs from:

- Casa Mesa Wind, LLC, a subsidiary of NextEra Energy Resources, LLC., which is expected to be located near House, New Mexico, have a total capacity of 50 MW, and be operational on December 31, 2018
- A 166 MW potion of the La Joya Wind Project, owned by Avangrid Renewables, LLC, which is expected to be located near Estancia, New Mexico and be operational in November 2020
- Route 66 Solar Energy Center, LLC, a subsidiary of NextEra Energy Resources, LLC., which is expected to be located west of Albuquerque, New Mexico, have a total capacity of 50 MW, and be operational in December 2021

Hazard Sharing Agreements

On June 1, 2016, PNM and Tri-State entered into a one-year hazard sharing agreement, which expired on May 31, 2017. PNM and Tri-State entered into an additional agreement, under substantially identical terms, for a term of five years beginning June 1, 2017, subject to NMPRC approval. NMPRC approval was not required for the one-year agreement, but was required for the five-year agreement. On May 10, 2017, the NMPRC issued an order approving the five-year agreement.

Under these agreements, each party sells the other party 100 MW of capacity and energy from each party's designated primary resource, which is SJGS Unit 4 for PNM and Springerville Generating Station Unit 3 for Tri-State, on a unit contingent basis subject to certain performance guarantees. The agreements reduce the magnitude of each party's single largest generating hazard and assist in enhancing the reliability and efficiency of their respective operations. Both purchases and sales are made at the same market index price. PNM passes the sales and purchases through to customers under PNM's FPPAC. Information about PNM's purchases and sales is as follows:

	Sales		Purchases	
	GWh	Amount	GWh	Amount
		(In millions)		(In millions)
Year ended December 31, 2017	827.1	$ 23.6	849.0	$ 24.2
Year ended December 31, 2016	482.3	12.8	484.6	12.9

Formula Transmission Rate Case

PNM filed an application with FERC for authorization to move from charging stated rates for wholesale electric transmission service to a formula rate mechanism pursuant to which rates for wholesale transmission service are calculated annually in accordance with an approved formula. The formula includes updating cost of service components, including investment in plant and operating expenses, based on information contained in PNM's annual financial report filed with FERC, as well as including projected large transmission capital projects to be placed into service in the following year. The projections included are subject to true-up in the following year formula rate. Certain items, including changes to return on equity and depreciation rates, require a separate filing to be made with FERC before being included in the formula rate. On March 20, 2015, PNM along with five other parties entered into a settlement agreement, which was filed at FERC. The settlement reflects a ROE of 10% and results in an annualized increase of $1.3 million above the rates approved in the previous rate case. On March 25, 2015, the ALJ issued an order authorizing the interim implementation of settled rates beginning on April 1, 2015, subject to refund. In May 2015, the settlement judge recommended that FERC approve the settlement. On March 17, 2016, FERC approved the settlement. PNM made the refunds required under the settlement in May 2016.

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Firm-Requirements Wholesale Customers

Navopache Electric Cooperative, Inc.

PNM had a PPA with NEC, previously PNM's largest firm-requirements wholesale customer, that had an expiration date of December 31, 2035. On April 8, 2015, NEC filed a petition for a declaratory order requesting that FERC find that NEC could purchase an unlimited amount of power and energy from third party supplier(s) under its PSA with PNM. Following proceedings before a settlement judge, PNM and NEC entered into, and filed with FERC, a settlement agreement on October 29, 2015 that includes certain amendments to the PSA and related contracts on file with FERC. FERC approved the settlement on January 21, 2016. Under the settlement agreement, PNM served all of NEC's load through December 31, 2015 at rates that were substantially consistent with those provided under the PSA. In 2016, PNM served all of NEC's load at reduced demand and energy rates from those under the PSA. Beginning January 1, 2016, NEC also paid certain third-party transmission costs that it only partially paid previously. The PSA and related transmission agreements terminated on December 31, 2016. In 2017, PNM served 10 MW of NEC's load under a short term coordination tariff at a rate lower than provided under the PSA. Amounts billed to NEC were $4.5 million, $20.0 million, and $27.1 million in the years ended December 31, 2017, 2016, and 2015. PNM's NM 2016 Rate Case discussed above reflects a reallocation of costs among regulatory jurisdictions reflecting the termination of the contract to serve NEC.

TNMP

Advanced Meter System Deployment

In July 2011, the PUCT approved a settlement and authorized an AMS deployment plan that permits TNMP to collect $113.4 million in deployment costs through a surcharge over a 12-year period. TNMP began collecting the surcharge on August 11, 2011. Deployment of advanced meters began in September 2011. TNMP completed its mass deployment in 2016 and has installed more than 242,000 advanced meters.

The PUCT adopted a rule creating a non-standard metering service for retail customers choosing to decline standard metering service via an advanced meter. The cost of providing non-standard metering service is to be borne by opt-out customers through an initial fee and ongoing monthly charge. As approved by the PUCT, TNMP is recovering $0.2 million in costs through initial fees ranging from $63.97 to $168.61 and ongoing annual expenses of $0.5 million through a $36.78 monthly fee. These amounts presume up to 1,081 consumers will elect the non-standard meter service, but TNMP has the right to adjust the fees if the number of anticipated consumers differs from that estimate. As of February 20, 2018, 99 consumers have made the election. TNMP does not expect the implementation of non-standard metering service to have a material impact on its financial position, results of operations, or cash flows.

On October 2, 2015, TNMP filed a reconciliation of the costs and savings of its AMS deployment program with the PUCT. Those costs include $71.0 million in capital costs and $18.0 million in operation and maintenance expenses. However, since the deployment was not complete and the total program costs to date were $1.5 million below the original approved forecasts, TNMP did not request a change to its monthly surcharge amount. The PUCT approved TNMP's reconciliation without adjustment on March 25, 2016. In connection with TNMP's deployment of AMS, TNMP committed to file a general rate case no later than September 1, 2018. TNMP will include a final reconciliation of AMS costs in the 2018 filing.

Energy Efficiency

TNMP recovers the costs of its energy efficiency programs through an energy efficiency cost recovery factor ("EECRF"), which includes projected program costs, under or over collected costs from prior years, rate case expenses, and performance bonuses (if the programs exceed mandated savings goals). The following sets forth TNMP's EECRF increases:

Effective Date	Aggregate Collection Amount	Performance Bonus
	(In millions)	
March 1, 2015	$ 5.7	$ 1.5
March 1, 2016	6.0	0.7
March 1, 2017	6.0	0.8
March 1, 2018	6.0	1.1

Transmission Cost of Service Rates

TNMP can update its transmission rates twice per year to reflect changes in its invested capital although updates are not allowed while a general rate case is in progress. Updated rates reflect the addition and retirement of transmission facilities, including appropriate depreciation, federal income tax and other associated taxes, and the approved rate of return on such facilities. The following sets forth TNMP's recent interim transmission cost rate increases:

Effective Date	Approved Increase in Rate Base	Annual Increase in Revenue
	(In millions)	
March 16, 2015	$ 27.1	$ 4.4
September 10, 2015	7.0	1.4
March 23, 2016	25.8	4.3
September 8, 2016	9.5	1.8
March 14, 2017	30.2	4.8
September 13, 2017	27.5	4.7

On January 30, 2018, TNMP filed an application to further update its transmission rates, which would increase revenues by $0.6 million annually, based on an increase in rate base of $3.2 million. The application is pending before the PUCT.

On March 23, 2017, the PUCT staff filed proposed amendments to the interim transmission cost of service filing rule. If approved, the amendments could reduce the frequency of such filings to once per year. The amendments could also reduce the amount recovered by requiring that changes in accumulated deferred income taxes be considered and would preclude filings by utilities earning more than their authorized rate of return using weather-normalized data. On February 15, 2018, the PUCT announced at an open meeting that they would not proceed with the proposed amendments.

Periodic Distribution Rate Adjustment

PUCT rules permit interim rate adjustments to reflect changes in investments in distribution assets. Distribution utilities may file for a periodic rate adjustment between April 1 and April 8 of each year as long as the electric utility is not earning more than its authorized rate of return using weather-normalized data. However, TNMP has not made a filing to adjust rates for additional investments in distribution assets. In connection with TNMP's deployment of its advanced meter system discussed above, TNMP committed to file a general rate case no later than September 1, 2018. TNMP has also committed that it would not file a request for an increase in rates to reflect changes in investments in distribution assets until after the 2018 general rate case.

Competition Transition Charge Compliance Filing

In connection with the adoption of legislation that deregulated electric utilities operating within ERCOT, TNMP was allowed to recover its stranded costs through the CTC and to also recover a carrying charge on the CTC. Further, the order authorizing TNMP's CTC included a true-up provision requiring an adjustment to the CTC due to a cumulative over- or under-collection of revenues, including interest, greater-than or equal to 15% of the most recent annual CTC funding amount. On March 13, 2017, TNMP made a filing to true-up the CTC. The requested adjustment reduces the collection of the amortization by $1.1 million annually. On April 3, 2017, the PUCT staff filed its recommendation to approve the requested adjustment. The change was approved on April 5, 2017 and went into effect on June 1, 2017.

Order Related to Changes in Federal Income Tax Rates

On January 25, 2018, the PUCT issued an accounting order that addresses the change in federal income tax rates on investor-owned utilities in the State of Texas. The order requires investor-owned utilities to record a regulatory liability equal to the reduction in accumulated federal deferred income tax balances at the end of 2017 due to the change in the

federal income tax rate. In addition, the order requires that a regulatory liability be recorded to reflect the difference between revenues collected under existing rates and those that would have been collected had those rates been set reflecting federal income tax reform beginning on the date of the order. The order provides that these regulatory liabilities will be considered by the PUCT in each utility's next rate proceeding, which for TNMP is anticipated to be filed in May 2018. TNMP is evaluating the order and what actions it will take, as are other investor-owned utilities operating in Texas.

(18) Goodwill

The excess purchase price over the fair value of the assets acquired and the liabilities assumed by PNMR for its 2005 acquisition of TNP was recorded as goodwill and was pushed down to the businesses acquired. In 2007, the TNMP assets that were included in its New Mexico operations, including goodwill, were transferred to PNM. PNMR's reporting units that currently have goodwill are PNM and TNMP.

GAAP requires the Company to evaluate its goodwill for impairment annually at the reporting unit level or more frequently if circumstances indicate that the goodwill may be impaired. Application of the impairment test requires judgment, including the identification of reporting units, assignment of assets and liabilities to reporting units, and determination of the fair value of each reporting unit.

GAAP provides that in certain circumstances an entity may perform a qualitative analysis to conclude that the goodwill of a reporting unit is not impaired. Under a qualitative assessment an entity considers macroeconomic conditions, industry and market considerations, cost factors, overall financial performance, other relevant entity-specific events affecting a reporting unit, as well as whether a sustained decrease (both absolute and relative to its peers) in share price has occurred. An entity considers the extent to which each of the adverse events and circumstances identified could affect the comparison of a reporting unit's fair value with its carrying amount. An entity places more weight on the events and circumstances that most affect a reporting unit's fair value or the carrying amount of its net assets. An entity also considers positive and mitigating events and circumstances that may affect its determination of whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. An entity evaluates, on the basis of the weight of evidence, the significance of all identified events and circumstances in the context of determining whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. A quantitative analysis is not required if, after assessing the totality of events or circumstances, an entity determines that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount.

In other circumstances, an entity may perform a quantitative analysis to reach the conclusion regarding impairment with respect to a reporting unit. An entity may choose to perform a quantitative analysis without performing a qualitative analysis and may perform a qualitative analysis for certain reporting units, but a quantitative analysis for others. The first step of the quantitative impairment test requires an entity to compare the fair value of the reporting unit with its carrying value, including goodwill. If as a result of this analysis, the entity concludes there is an indication of impairment in a reporting unit having goodwill, GAAP currently requires the entity to perform the second step of the impairment analysis, determining the amount of goodwill impairment to be recorded. The amount is calculated by comparing the implied fair value of the goodwill to its carrying amount. This exercise would require the entity to allocate the fair value determined in step one to the individual assets and liabilities of the reporting unit. Any remaining fair value would be the implied fair value of goodwill on the testing date. To the extent the recorded amount of goodwill of a reporting unit exceeds the implied fair value determined in step two, an impairment loss would be reflected in results of operations. As further discussed under New Accounting Pronouncements in Note 1, a new accounting pronouncement changes how goodwill impairment is determined by eliminating the second step of the quantitative impairment analysis.

For both the PNM and TNMP reporting units, PNMR utilized qualitative analyses for the annual evaluations performed as of April 1, 2017 and quantitative analyses for the evaluations performed as of April 1, 2016. For the annual evaluations performed as of April 1, 2015, PNMR utilized a quantitative analysis for the PNM reporting unit and a qualitative analysis for the TNMP reporting unit.

For the April 1, 2017 evaluation for both the PNM and TNMP reporting units, the qualitative analyses were performed by considering changes in the Company's expectations of future financial performance since the April 1, 2016 quantitative analyses. These analyses considered Company specific events such as the potential impacts of legal and regulatory matters discussed in Note 16 and Note 17, including the estimated impacts of the proposed revised stipulation in the PNM NM 2016 Rate Case, the impacts of potential outcomes of the matters appealed to the NM Supreme Court under the NM 2015 Rate Case, and the impacts of changes in PNM's resource needs based on PNM's 2017 IRP. These evaluations also considered changes in TNMP's regulatory environment such as the PUCT's proposed amendments to the interim transmission cost of service filing rule, as well as potential outcomes associated with TNMP's general rate case filing, which the Company anticipates filing in May 2018. The qualitative analyses also considered market and macroeconomic factors including changes in anticipated growth rates, anticipated changes in the WACC, and changes in discount rates. The Company also evaluated its stock price relative to historical performance, industry peers, and to major market indices, including an evaluation of the Company's market capitalization relative to the carrying valu

e of its reporting units. Based on an evaluation of these and other factors, the Company determined it is not more likely than not that the April 1, 2017 carrying values of PNM or TNMP exceed their fair values.

For its annual evaluations performed as of April 1, 2016, PNMR performed quantitative analyses for both the PNM and TNMP reporting units. For the quantitative analyses, a discounted cash flow methodology was primarily used to estimate the fair value of the reporting unit. This analysis requires significant judgments, including estimation of future cash flows, which is dependent on internal forecasts, estimation of long-term growth rates for the business, and determination of appropriate WACC for each reporting unit. Changes in these estimates and assumptions could materially affect the determination of fair value and the conclusion of impairment. The April 1, 2016 and 2015 quantitative evaluations for PNM both indicated the fair value of the PNM reporting unit, which has goodwill of $51.6 million, exceeded its carrying value by approximately 25%. An increase of 0.5% in the expected return on equity capital utilized in discounting the forecasted cash flows, would have reduced the excess of PNM's fair value over carrying value to approximately 18%. The April 1, 2016 quantitative evaluation indicated the fair value of the TNMP reporting unit, which has goodwill of $226.7 million, exceeded its carrying value by 32%. An increase of 0.5% in the expected return on equity capital utilized in calculating the WACC used to discount the forecasted cash flows, would have reduced the excess of TNMP's fair value over carrying value to approximately 21% at April 1, 2016.

The 2015 qualitative analysis for TNMP included the consideration of various reporting unit specific factors as well as industry and macroeconomic factors to determine whether

these factors were reasonably likely to have a material impact on the fair value of the reporting unit. Factors considered included the results of the April 1, 2012 quantitative analysis, which indicated that fair value of the reporting unit exceeded its carrying value by approximately 26%, current and long-term forecasted financial results, regulatory environment, credit rating, interest rate environment, absolute and relative price of PNMR's common stock, and operating strategy. TNMP believes it is operating within a generally favorable regulatory environment, its historical and forecasted financial results are positive, and its credit is generally perceived positively. Based on the analysis of the relevant factors, PNMR concluded that it was more likely than not that the fair value of the TNMP reporting unit exceeds its carrying value at April 1, 2015.

Prior annual evaluations have not indicated impairments of any of PNMR's reporting units, except in 2008. During 2008, the market capitalization of PNMR's common stock was significantly below book value. In addition, a PNMR reporting unit, which was sold in 2011 was significantly impacted by depressed economic conditions and changes in the market in which it operated. As a result, goodwill impairments of $51.1 million for PNM, $34.5 million for TNMP, and an aggregate of $174.4 million for PNMR were recorded in 2008. Since 2008, the price of PNMR's common stock has increased, improving the relationship between PNMR's market capitalization and book value. In addition, improved regulatory treatment has been experienced by PNM in New Mexico and by TNMP in Texas. These factors resulted in more predictable earnings and increased fair values of the reporting units. Since 2008, the annual evaluations have not indicated that the fair values of the reporting units with recorded goodwill have decreased below their carrying values.

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(19) Accumulated Other Comprehensive Income (Loss)

AOCI reports a measure for accumulated changes in equity that result from transactions and other economic events other than transactions with shareholders. Information regarding AOCI is as follows:

	Accumulated Other Comprehensive Income (Loss)				
	PNM			PNMR	
	Unrealized Gains on Available-for-Sale Securities	Pension Liability Adjustment	Total	Fair Value Adjustment for Cash Flow Hedges	Total
			(In thousands)		
Balance at December 31, 2014	$ 28,008	$ (89,763)	$ (61,755)	$ —	$ (61,755)
Amounts reclassified from AOCI (pre-tax)	(28,531)	5,952	(22,579)	—	(22,579)
Income tax impact of amounts reclassified	11,181	(2,332)	8,849	—	8,849
Other OCI changes (pre-tax)	10,998	(4,405)	6,593	72	6,665
Income tax impact of other OCI changes	(4,310)	1,726	(2,584)	(28)	(2,612)
Net after-tax change	(10,662)	941	(9,721)	44	(9,677)
Balance at December 31, 2015	17,346	(88,822)	(71,476)	44	(71,432)
Amounts reclassified from AOCI (pre-tax)	(22,139)	5,504	(16,635)	764	(15,871)
Income tax impact of amounts reclassified	8,639	(2,148)	6,491	(298)	6,193
Other OCI changes (pre-tax)	778	(18,501)	(17,723)	(874)	(18,597)
Income tax impact of other OCI changes	(304)	7,219	6,915	341	7,256
Net after-tax change	(13,026)	(7,926)	(20,952)	(67)	(21,019)
Balance at December 31, 2016	4,320	(96,748)	(92,428)	(23)	(92,451)
Amounts reclassified from AOCI (pre-tax)	(17,567)	6,452	(11,115)	581	(10,534)
Income tax impact of amounts reclassified	6,816	(2,504)	4,312	(225)	4,087
Other OCI changes (pre-tax)	28,160	3,618	31,778	1,000	32,778
Income tax impact of other OCI changes	(10,927)	(919)	(11,846)	(388)	(12,234)
Net after-tax change	6,482	6,647	13,129	968	14,097
Reclassification of stranded income taxes to retained earnings Note 11	2,367	(20,161)	(17,794)	208	(17,586)
Balance at December 31, 2017	$ 13,169	$ (110,262)	$ (97,093)	$ 1,153	$ (95,940)

Pre-tax amounts reclassified from AOCI related to "Unrealized Gains on Available-for-Sale Securities" are included in "Gains on available-for-sale securities" in the Consolidated Statements of Earnings. Pre-tax amounts reclassified from AOCI related to "Pension Liability Adjustment" are reclassified to "Operating Expenses – Administrative and general" in the Consolidated Statements of Earnings. Pre-tax amounts reclassified from AOCI related to "Fair Value Adjustment for Cash Flow Hedges" are reclassified to "Interest Charges" in the Consolidated Statements of Earnings. An insignificant amount is included in capitalized interest. The income tax impacts of all amounts reclassified from AOCI are included in "Income Taxes" in the Consolidated Statements of Earnings.

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(20) Quarterly Operating Results (Unaudited)

Unaudited operating results by quarters for 2017 and 2016 are presented below. In the opinion of management of the Company, all adjustments (consisting of normal recurring

accruals) necessary for a fair statement of the results of operations for such periods have been included.

	Quarter Ended			
	March 31	June 30	September 30	December 31 [1]
	(In thousands, except per share amounts)			
PNMR				
2017				
Operating revenues	$ 330,178	$ 362,320	$ 419,900	$ 332,605
Operating income	55,960	85,105	142,484	22,936
Net earnings (loss)	26,446	41,231	78,327	(50,585)
Net earnings (loss) attributable to PNMR	22,862	37,555	73,739	(54,282)
Net earnings (loss) attributable to PNMR per common share:				
Basic	0.29	0.47	0.92	(0.68)
Diluted	0.29	0.47	0.92	(0.68)
2016				
Operating revenues	$ 310,961	$ 315,391	$ 400,374	$ 336,225
Operating income	41,508	64,822	108,071	63,584
Net earnings	13,965	30,952	58,556	28,423
Net earnings attributable to PNMR	10,546	27,076	54,418	24,809
Net earnings attributable to PNMR per common share:				
Basic	0.13	0.34	0.68	0.32
Diluted	0.13	0.34	0.68	0.31
PNM				
2017				
Operating revenues	$ 251,558	$ 276,097	$ 327,254	$ 249,321
Operating income	38,331	59,164	113,252	1,778
Net earnings (loss)	20,110	30,476	65,283	(28,456)
Net earnings (loss) attributable to PNM	16,658	26,932	60,827	(32,021)
2016				
Operating revenues	$ 235,606	$ 233,346	$ 311,276	$ 255,685
Operating income	23,297	41,760	80,057	42,976
Net earnings	7,561	19,793	44,990	19,594
Net earnings attributable to PNM	4,274	16,049	40,984	16,112
TNMP				
2017				
Operating revenues	$ 78,620	$ 86,223	$ 92,646	$ 83,284
Operating income	17,965	26,286	29,474	19,879
Net earnings	7,604	12,204	14,727	1,024
2016				
Operating revenues	$ 75,355	$ 82,045	$ 89,098	$ 80,540
Operating income	18,554	23,375	28,359	21,353
Net earnings	7,456	10,508	13,853	9,855

[1] Reflects the impacts of changes in federal income tax rate of $57.5 million, $29.6 million, and $7.9 million for PNMR, PNM, and TNMP (Note 11); also reflects a pre-tax regulatory disallowance resulting from PNM's NM 2016 Rate Case of $27.9 million for PNMR and PNM (Note 17).

SCHEDULE I
PNM RESOURCES, INC.
CONDENSED FINANCIAL INFORMATION OF PARENT COMPANY
STATEMENTS OF EARNINGS

	Year ended December 31,		
	2017	2016	2015
	(In thousands)		
Operating Revenues	$ —	$ —	$ —
Operating Expenses	2,902	2,871	1,221
Operating income (loss)	(2,902)	(2,871)	(1,221)
Other Income and Deductions:			
Equity in earnings of subsidiaries	111,877	122,252	27,352
Other income	1,181	1,711	747
Net other income and deductions	113,058	123,963	28,099
Interest Charges	12,490	8,102	8,275
Earnings Before Income Taxes	97,666	112,990	18,603
Income Tax Expense (Benefit)	17,792	(3,859)	2,963
Net Earnings	$ 79,874	$ 116,849	$ 15,640

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SCHEDULE I
PNM RESOURCES, INC.
CONDENSED FINANCIAL INFORMATION OF PARENT COMPANY
STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Net Cash Flows From Operating Activities	$ (7,814)	$ 5,702	$ 1,375
Cash Flows From Investing Activities:			
Utility plant additions	(180)	341	368
Investments in subsidiaries	(50,000)	(98,343)	(175,000)
Cash dividends from subsidiaries	105,084	35,959	127,688
Net cash flows from investing activities	54,904	(62,043)	(46,944)
Cash Flows From Financing Activities:			
Short-term loan	—	100,000	50,000
Repayment of short-term loan	—	(150,000)	—
Revolving credit facility borrowings (repayments), net	42,600	84,500	41,000
Long-term borrowings	—	100,000	150,000
Repayment of long-term debt	—	—	(118,766)
Proceeds from stock option exercise	1,739	7,028	5,619
Purchases to satisfy awards of common stock	(13,929)	(15,451)	(17,720)
Dividends paid	(77,264)	(70,095)	(63,723)
Other, net	(269)	(28)	(782)
Net cash flows from financing activities	(47,123)	55,954	45,628
Change in Cash and Cash Equivalents	(33)	(387)	59
Cash and Cash Equivalents at Beginning of Period	54	441	382
Cash and Cash Equivalents at End of Period	$ 21	$ 54	$ 441
Supplemental Cash Flow Disclosures:			
Interest paid, net of amounts capitalized	$ 10,899	$ 5,906	$ 7,559
Income taxes paid (refunded), net	$ —	$ —	$ (730)

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SCHEDULE I

PNM RESOURCES, INC.
CONDENSED FINANCIAL INFORMATION OF PARENT COMPANY
BALANCE SHEETS

	December 31,	
	2017	2016
	(In thousands)	
Assets		
Cash and cash equivalents	$ 21	$ 54
Intercompany receivables	96,227	92,234
Income taxes receivable	1,818	—
Other, net	1,937	233
Total current assets	100,003	92,521
Property, plant and equipment, net of accumulated depreciation of $13,229 and $12,291	26,546	26,366
Investment in subsidiaries	2,056,198	1,986,276
Other long-term assets	66,090	79,314
Total long-term assets	2,148,834	2,091,956
	$ 2,248,837	$ 2,184,477
Liabilities and Stockholders' Equity		
Short-term debt	$ 265,600	$ 226,100
Short-term debt-affiliate	11,919	8,819
Current maturities of long-term debt	249,979	—
Accrued interest and taxes	1,661	1,333
Other current liabilities	21,274	19,374
Total current liabilities	550,433	255,626

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Long-term debt	—	249,895
Other long-term liabilities	3,151	3,004
Total liabilities	553,584	508,525
Common stock (no par value; 120,000,000 shares authorized; issued and outstanding 79,653,624 shares)	1,157,665	1,163,661
Accumulated other comprehensive income (loss), net of tax	(95,940)	(92,451)
Retained earnings	633,528	604,742
Total common stockholders' equity	1,695,253	1,675,952
	$ 2,248,837	$ 2,184,477

See Notes 6, 7, 14, and 16 for information regarding commitments, contingencies, and maturities of long-term debt.

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SCHEDULE II
PNM RESOURCES, INC. AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at beginning of year	Additions: Charged to costs and expenses	Additions: Charged to other accounts	Deductions: Write-offs and other	Balance at end of year
			(In thousands)		
Allowance for doubtful accounts, year ended December 31:					
2015	$ 1,466	$ 3,358	$ —	$ 3,427	$ 1,397
2016	$ 1,397	$ 2,885	$ —	$ 3,073	$ 1,209
2017	$ 1,209	$ 2,619	$ —	$ 2,747	$ 1,081

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SCHEDULE II
PUBLIC SERVICE COMPANY OF NEW MEXICO AND SUBSIDIARY
A WHOLLY-OWNED SUBSIDIARY OF PNM RESOURCES, INC.
VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at beginning of year	Additions: Charged to costs and expenses	Additions: Charged to other accounts	Deductions: Write-offs	Balance at end of year
			(In thousands)		
Allowance for doubtful accounts, year ended December 31:					
2015	$ 1,466	$ 3,344	$ —	$ 3,413	$ 1,397
2016	$ 1,397	$ 2,871	$ —	$ 3,059	$ 1,209
2017	$ 1,209	$ 2,615	$ —	$ 2,743	$ 1,081

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SCHEDULE II
TEXAS-NEW MEXICO POWER COMPANY AND SUBSIDIARIES
A WHOLLY-OWNED SUBSIDIARY OF PNM RESOURCES, INC.
VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at beginning of year	Additions: Charged to costs and expenses	Additions: Charged to other accounts	Deductions: Write-offs	Balance at end of year
			(In thousands)		

Allowance for doubtful accounts, year ended December 31:												
2015	$	—	$	14	$	—	$	14	$	—		
2016	$	—	$	14	$	—	$	14	$	—		
2017	$	—	$	4	$	—	$	4	$	—		

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

PNMR

(a) Evaluation of disclosure controls and procedures.

As of the end of the period covered by this annual report, PNMR conducted an evaluation under the supervision and with the participation of its management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934). Based upon this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures are effective as of the end of the period covered by this report.

(b) Management's report on internal control over financial reporting.

"Management's Annual Report on Internal Control Over Financial Reporting" appears on page B-2. This report is incorporated by reference herein. PNMR's internal control over financial reporting as of December 31, 2017 has been audited by KPMG LLP, as an independent registered public accounting firm, as stated in their report which is included herein.

(c) Changes in internal controls.

There have been no changes in PNMR's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the quarter ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, PNMR's internal control over financial reporting.

PNM

(a) Evaluation of disclosure controls and procedures.

As of the end of the period covered by this annual report, PNM conducted an evaluation under the supervision and with the participation of its management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934). Based upon this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures are effective as of the end of the period covered by this report.

(b) Management's report on internal control over financial reporting.

"Management's Annual Report on Internal Control Over Financial Reporting" appears on page B-3. This report is incorporated by reference herein.

(c) Changes in internal controls.

There have been no changes in PNM's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the quarter ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, PNM's internal control over financial reporting.

TNMP

(a) Evaluation of disclosure controls and procedures.

As of the end of the period covered by this annual report, TNMP conducted an evaluation under the supervision and with the participation of its management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934). Based upon this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures are effective as of the end of the period covered by this report.

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(b) Management's report on internal control over financial reporting.

"Management's Annual Report on Internal Control Over Financial Reporting" appears on page B-4. This report is incorporated by reference herein.

(c) Changes in internal controls.

There have been no changes in TNMP's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the quarter ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, TNMP's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

Reference is hereby made to "Proposal 1: Elect Eight Directors" in PNMR's Proxy Statement relating to the annual meeting of stockholders to be held on May 22, 2018 (the "2018 Proxy Statement"), to PART I, SUPPLEMENTAL ITEM – "EXECUTIVE OFFICERS OF THE COMPANY" in this Form 10-K, "Section 16(a) Beneficial Ownership Reporting Compliance", "Code of Ethics," and "Board Committees and Their Functions" – "Audit and Ethics Committee" in the 2018 Proxy Statement. The Company intends to satisfy the disclosure requirements of Form 8-K relating to amendments to the Company's code of ethics applicable to its senior executive and financial officers by posting such information on its Internet website. Information about the Company's website is included under Part I, Item 1 – "Websites."

ITEM 11. EXECUTIVE COMPENSATION

Reference is hereby made to "Executive Compensation", and all subheadings thereunder from "Compensation Discussion and Analysis" to "Change in Control, Termination, Retirement, or Impaction", "Director Compensation," and "Board Committees and Their Functions – Compensation and Human Resources Committee / Nominating and Governance Committee – Interlocks and Insider Participation" in the 2018 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Reference is hereby made to "Ownership of Our Common Stock – Five Percent Shareholders" and " – Executive Officers and Directors" and "Equity Compensation Plan Information" in the 2018 Proxy Statement.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Reference is hereby made to "Information About Our Corporate Governance – Related Person Transaction Policy" and " – Director Independence" in the 2018 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Reference is hereby made to "Audit and Ethics Committee Report" and "Independent Auditor Fees" in the 2018 Proxy Statement. Independent auditor fees for PNM and TNMP are reported in the 2018 Proxy Statement for PNMR. All such fees are fees of PNMR. PNMR charges a management fee to PNM and TNMP that includes an allocation of independent auditor fees.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) - 1. See Index to Financial Statements under Part II, Item 8.

(a) - 2. Financial Statement Schedules for the years 2017, 2016, and 2015 are omitted for the reason that they are not required or the information is otherwise supplied under Part II, Item 8.

(a) - 3-A. Exhibits Filed:

Exhibit No		Description
10.1**	PNMR	PNMR Director Deferred Stock Rights Program effective December 1, 2017
10.2**	PNMR	Second Amendment to PNMR Executive Spending Account Plan executed December 13, 2017
10.3	PNMR	First Amendment to Term Loan Agreement dated November 30, 2017 between PNMR and JPMorgan Chase Bank, N.A., as lender and administrative agent
10.4	PNM	Amendment No. 1 to Coal Supply Agreement dated November 1, 2017 between Westmoreland Coal Company and PNM
10.5**	PNMR	Acknowledgement Form with attached Terms and Conditions for restricted stock rights granted to directors on and after 2018 under the PNMR 2014 Performance Equity Plan dated May 15, 2014
10.6**	PNMR	Third Amendment (executed November 11, 2015) to PNMR Non-Union Severance Pay Plan
12.1	PNMR	Ratio of Earnings to Fixed Charges
12.2	PNM	Ratio of Earnings to Fixed Charges
12.3	TNMP	Ratio of Earnings to Fixed Charges
21	PNMR	Certain subsidiaries of PNM Resources, Inc.
23.1	PNMR	Consent of KPMG LLP for PNM Resources, Inc.
23.2	PNM	Consent of KPMG LLP for Public Service Company of New Mexico
31.1	PNMR	Chief Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	PNMR	Chief Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.3	PNM	Chief Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.4	PNM	Chief Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.5	TNMP	Chief Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

31.6	TNMP	Chief Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	PNMR	Chief Executive Officer and Chief Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	PNM	Chief Financial Officer and Chief Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.3	TNMP	Chief Executive Officer and Chief Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	PNMR	XBRL Instance Document
101.SCH	PNMR	XBRL Taxonomy Extension Schema Document
101.CAL	PNMR	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	PNMR	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	PNMR	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	PNMR	XBRL Taxonomy Extension Presentation Linkbase Document

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(a) -3- B. Exhibits Incorporated By Reference:

The documents listed below are being filed (as shown above) or have been previously filed on behalf of PNM Resources, PNM or TNMP and are incorporated by reference to the filings set forth below pursuant to Exchange Act Rule 12b-32 and Regulation S-K section 10, paragraph (d).

Exhibit No.	Description of Exhibit	Filed as Exhibit:	Registrant (s) File No:
Articles of Incorporation and By-laws			
3.1	Articles of Incorporation of PNMR, as amended to date (Certificate of Amendment dated October 27, 2008 and Restated Articles of Incorporation dated August 3, 2006)	3.1 to PNMR's Current Report on Form 8-K filed November 21, 2008	1-32462 PNMR
3.2	Restated Articles of Incorporation of PNM, as amended through May 31, 2002	3.1.1 to PNM's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002	1-6986 PNM
3.3	Articles of Incorporation of TNMP, as amended through July 7, 2005	3.1.2 to TNMP's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005	2-97230 TNMP
3.4	Bylaws of PNMR, Inc. with all amendments to and including October 24, 2017	3.4 to PNMR's Current Report on Form 8-K filed October 25, 2017	1-32462 PNMR
3.5	Bylaws of PNM with all amendments to and including May 31, 2002	3.1.2 to PNM's Report on Form 10-Q for the quarter ended June 30, 2002	1-6986 PNM
3.6	Bylaws of TNMP with all amendments to and including June 18, 2013	3.6 to TNMP's Current Report on Form 8-K filed June 20, 2013	2-97230 TNMP
Indentures‡			
PNMR			
4.1	Indenture, dated as of March 15, 2005, between PNMR and JPMorgan Chase Bank, N.A., as Trustee	10.2 to PNMR's Current Report on Form 8-K filed March 31, 2005	1-32462 PNMR
4.2	Supplemental Indenture No. 1, dated as of March 30, 2005, between PNMR and JPMorgan Chase Bank, N.A. as Trustee, with Form of Senior Note included as Exhibit A thereto	10.3 to PNMR's Current Report on Form 8-K filed March 31, 2005	333-32170 PNMR
4.3	Supplemental Indenture No. 2, dated as of May 16, 2008 between PNMR and The Bank of New York Trust Company, N.A. (successor to JPMorgan Chase Bank, N.A.), as trustee	4.3 to PNMR's Current Report on Form 8-K filed May 21, 2008	1-32462 PNMR
4.4	Agreement of Resignation, Appointment and Acceptance, effective as of June 1, 2011, among PNMR, The Bank of New York Mellon Trust Company, N.A. and Union Bank, N.A. (for March 15, 2005 PNMR Indenture)	4.1 to PNMR's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011	1-32462 PNMR
PNM			
4.5	Indenture (for Senior Notes), dated as of March 11, 1998, between PNM and The Chase Manhattan Bank, as Trustee	4.4 to PNM's Quarterly Report on Form 10-Q for the quarter ended March 31, 1998	1-6986 PNM
4.6	First Supplemental Indenture, dated as of March 11, 1998, supplemental to Indenture dated as of March 11, 1998, between PNM and The Chase Manhattan Bank, as Trustee	4.5 to PNM's Quarterly Report on Form 10-Q for the quarter ended March 31, 1998	1-6986 PNM
4.7	Second Supplemental Indenture, dated as of March 11, 1998, supplemental to Indenture dated as of March 11, 1998, between PNM and The Chase Manhattan Bank, as Trustee	4.6 to PNM's Quarterly Report on Form 10-Q for the quarter ended March 31, 1998	1-6986 PNM

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4.8	Third Supplemental Indenture, dated as of October 1, 1999, supplemental to Indenture dated as of March 11, 1998, between PNM and The Chase Manhattan Bank, as Trustee	4.6.1 to PNM's Annual Report on Form 10-K for the year ended December 31, 1999	1-6986 PNM
4.9	Fourth Supplemental Indenture, dated as of May 1, 2003, supplemental to Indenture dated as of March 11, 1998, between PNM and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee	4.6.2 to PNM's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003	1-6986 PNM
4.10	Fifth Supplemental Indenture, dated as of May 1, 2003, supplemental to Indenture dated as of March 11, 1998, between PNM and JPMorgan Chase Bank, as Trustee	4.6.3 to PNM's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003	1-6986 PNM
4.11	Sixth Supplemental Indenture, dated as of May 1, 2003, supplemental to Indenture dated as of March 11, 1998, between PNM and JPMorgan Chase Bank, as Trustee	4.6.4 to PNM's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003	1-6986 PNM
4.12	Seventh Supplemental Indenture, dated as of June 1, 2007, supplemental to Indenture dated as of March 11, 1998, between PNM and The Bank of New York Trust Company, N.A. (successor to JPMorgan Chase Bank), as Trustee	4.23 to PNM's Quarterly Report on Form 10-Q for the quarter ended June 30, 2007	1-6986 PNM
4.13	Eighth Supplemental Indenture, dated as of June 1, 2010, supplemental to Indenture dated as of March 11, 1998, between PNM and The Bank of New York Mellon Trust Company (successor to JPMorgan Chase Bank), as Trustee	10.1 to PNM's Current Report on Form 8-K/A filed July 29, 2010	1-6986 PNM
4.14	Ninth Supplemental Indenture, dated as of June 1, 2010, supplemental to Indenture dated as of March 11, 1998, between PNM and The Bank of New York Mellon Trust Company (successor to JPMorgan Chase Bank), as Trustee	10.2 to PNM's Current Report on Form 8-K/A filed July 29, 2010	1-6986 PNM
4.15	Agreement of Resignation, Appointment and Acceptance effective as of May 1, 2011, among PNM, The Bank of New York Mellon Trust Company, N.A. and Union Bank, N.A. (for March 11, 1998 PNM Indenture)	4.2 to PNM's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011	1-6986 PNM
4.16	Tenth Supplemental Indenture, dated as of September 1, 2012, supplemental to Indenture dated as of March 11, 1998, between PNM and Union Bank, N.A.(ultimate successor as trustee to The Chase Manhattan Bank), as Trustee	4.1 to PNM's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012	1-6986 PNM
4.17	Eleventh Supplemental Indenture, dated as of September 1, 2016, supplemental to Indenture dated as of March 11, 1998, between PNM and MUFG Union Bank, N.A. (formerly Union Bank, N.A.) (ultimate successor as trustee to The Chase Manhattan Bank), as Trustee	4.1 to PNM's Current Report on Form 8-K filed September 27, 2016	1-6986 PNM
4.18	Indenture (for Senior Notes), dated as of August 1, 1998, between PNM and The Chase Manhattan Bank, as Trustee	4.1 to PNM's Registration Statement No. 333-53367	333-53367 PNM
4.19	First Supplemental Indenture, dated August 1, 1998, supplemental to Indenture, dated as of August 1, 1998, between PNM and The Chase Manhattan Bank, as Trustee	4.3 to PNM's Current Report on Form 8-K filed August 7, 1998	1-6986 PNM
4.20	Second Supplemental Indenture, dated September 1, 2003, supplemental to Indenture, dated as of August 1, 1998, between PNM and JPMorgan Chase Bank (formerly, The Chase Manhattan Bank), as Trustee	4.7.1 to PNM's Quarterly Report on Form 10-Q for the quarter ended September 30, 2003	1-6986 PNM

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4.21	Third Supplemental Indenture, dated as of May 13, 2008, supplemental to Indenture dated as of August 1, 1998, between PNM and The Bank of New York Trust Company, N.A. as Trustee	4.1 to PNM's Current Report on Form 8-K filed May 15, 2008	1-6986 PNM
4.22	Agreement of Resignation, Appointment and Acceptance, effective as of June 1, 2011, among PNM, The Bank of New York Mellon Trust Company and Union Bank, N.A. (for August 1, 1998 PNM Indenture)	4.3 to PNM's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011	1-6986 PNM
4.23	Fourth Supplemental Indenture, dated as of October 12, 2011, supplemental to Indenture dated as of August 1, 1998, between PNM and Union Bank, N.A. (ultimate successor as trustee to The Chase Manhattan Bank), as Trustee	4.1 to PNM's Current Report on Form 8-K filed October 12, 2011	1-6986 PNM
4.24	Fifth Supplemental Indenture, dated as of August 11, 2015, supplemental to the Indenture dated as of August 1, 1998, between PNM and MUFG Union Bank, N.A., as Trustee	4.2 to PNM's Current Report on Form 8-K filed August 11, 2015	1-6986 PNM
TNMP			
4.25	First Mortgage Indenture dated as of March 23, 2009 between TNMP and The Bank of New York Mellon Trust Company, N.A., as Trustee	4.1 to TNMP's Current Report on Form 8-K filed March 27, 2009	2-97230 TNMP
4.26	First Supplemental Indenture dated as of March 23, 2009 between TNMP and The Bank of New York Mellon Trust Company, N.A., as Trustee	4.2 to TNMP's Current Report on Form 8-K filed March 27, 2009	2-97230 TNMP
4.27	Second Supplemental Indenture dated as of March 25, 2009 between TNMP and The Bank of New York Mellon Trust Company, N.A., as Trustee	4.3 to TNMP's Current Report on Form 8-K filed March 27, 2009	2-97230 TNMP
4.28	Third Supplemental Indenture dated as of April 30, 2009 between TNMP and The	4.1 to TNMP's Current Report on Form 8-K filed	2-97230

	Bank of New York Mellon Trust Company, N.A., as Trustee	May 6, 2009	TNMP
4.29	First Amendment dated as of December 16, 2010 between TNMP and The Bank of New York Mellon Trust Company, N.A., as Trustee to The Third Supplemental Indenture dated as of April 30, 2009	4.1 to TNMP's Current Report on Form 8-K filed December 17, 2010	2-97230 TNMP
4.30	Agreement of Resignation, Appointment and Acceptance, effective as of June 1, 2011, among TNMP, The Bank of New York Mellon Trust Company, N.A. and Union Bank, N.A. (for March 23, 2009 TNMP Indenture)	4.4 to TNMP's Quarterly Report Form 10-Q for the quarter ended June 30, 2011	2-97230 TNMP
4.31	Fourth Supplemental Indenture dated as of September 30, 2011 between TNMP and Union Bank, N.A., as Trustee	4.1 to TNMP's Current Report on Form 8-K filed October 6, 2011	2-97230 TNMP
4.32	Fifth Supplemental Indenture dated as of April 3, 2013 between TNMP and Union Bank, N.A., as Trustee	4.1 to TNMP's Current Report on Form 8-K filed April 3, 2013	2-97230 TNMP
4.33	Sixth Supplemental Indenture dated as of June 27, 2014 between TNMP and Union Bank, N.A., as Trustee	4.1 to TNMP's Current Report on Form 8-K filed June 27, 2014	2-97230 TNMP
4.34	Seventh Supplemental Indenture dated as of February 10, 2016 between TNMP and MUFG Union Bank, N.A., as Trustee	4.1 to TNMP's Current Report on Form 8-K filed February 10, 2016	2-97230 TNMP
4.35	Eighth Supplemental Indenture dated as of August 24, 2017 between TNMP and MUFG Union Bank, N.A., as Trustee	4.1 to TNMP's Current Report on Form 8-K filed August 24, 2017	2-97230 TNMP

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Material Contracts

10.7	Credit Agreement dated as of October 31, 2011 among PNMR, the lenders party thereto, Wells Fargo Bank, National Association, as administrative agent and Union Bank, N.A., as syndication agent	10.1 to PNMR's Current Report on Form 8-K filed October 31, 2011	1-32462 PNMR
10.8	First Amendment to Credit Agreement dated January 18, 2012 among PNMR, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent	10.1 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2011	1-32462 PNMR
10.9	Second Amendment to Credit Agreement dated October 31, 2013 among PNMR, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent	10.2 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2013	1-32462 PNMR
10.10	Third Amendment to Credit Agreement dated December 17, 2014 among PNMR, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent	10.1 to PNMR's Current Report on Form 8-K filed December 17, 2014	1-32462 PNMR
10.11	Fourth Amendment to Credit Agreement dated September 9, 2015 among PNMR, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent	10.6 to PNMR's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015	1-32462 PNMR
10.12	Fifth Amendment to Credit Agreement effective November 2, 2016 among PNMR, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent	10.1 to PNMR's Current Report on Form 8-K filed November 4, 2016	1-32462 PNMR
10.13	Term Loan Agreement dated December 21, 2016 among PNMR, the lenders identified therein, and Wells Fargo Bank, National Association, as administrative agent	10.1 to PNMR's Current Report on Form 8-K filed December 21, 2016	1-32462 PNMR
10.14	First Amendment to Term Loan Agreement dated December 15, 2017 among PNMR, the lenders identified therein, and Wells Fargo Bank, National Association as administrative agent	10.1 to PNMR's Current Report on Form 8-K filed December 18, 2017	1-32462 PNMR
10.15	Term Loan Agreement dated December 21, 2016 among PNMR, the lenders identified therein, and JPMorgan Chase Bank, N.A., as administrative agent	10.2 to PNMR's Current Report on Form 8-K filed December 21, 2016	1-32462 PNMR
10.16	First Amendment to Term Loan Agreement dated November 30, 2017 between PNMR and JPMorgan Chase Bank, N.A., as lender and administrative agent	10.3 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2017	1-32462 PNMR
10.17	Third Amended and Restated Term Loan Agreement dated as of December 21, 2015 among PNMR, the lenders identified therein and JPMorgan Chase Bank, N.A., as administrative agent (terminated December 21, 2016)	10.1 to PNMR's Current Report on Form 8-K filed December 21, 2015	1-32462 PNMR
10.18	Term Loan Agreement dated as of March 9, 2015 among PNMR, the lenders identified therein and Wells Fargo Bank, National Association, as administrative agent	10.1 to PNMR's Current Report on Form 8-K filed March 9, 2015	1-32462 PNMR
10.19	First Amendment to Term Loan Agreement dated September 9, 2015 among PNMR, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent	10.7 to PNMR's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015	1-32462 PNMR
10.20	Second Amendment to Term Loan Agreement effective November 2, 2016 among PNMR, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent	10.3 to PNMR's Current Report on Form 8-K filed November 4, 2016	1-32462 PNMR

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10.21	Term Loan Agreement dated as of February 1, 2016 among NM Capital, as borrower and BTMU, as lender and administrative agent ("BTMU Loan Agreement")	10.1 to PNMR's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016	1-32462 PNMR
10.22	Guaranty Agreement dated as of February 1, 2016 made by PNMR in favor of the lenders under the BTMU Loan Agreement	10.2 to PNMR's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016	1-32462 PNMR
10.23	First Amendment to the Guaranty Agreement dated as of December 21, 2016, made by PNMR in favor of the lenders under the BTMU Loan Agreement	10.5 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2016	1-32462 PNMR
10.24	Loan Agreement dated as of February 1, 2016 among WSJ, as borrower, the guarantors named therein, NM Capital, as lender, BTMU, as administrative agent, and MUFG Union Bank, N.A., as depository bank	10.3 to PNMR's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016	1-32462 PNMR
10.25	Reclamation Bond Agreement dated January 31, 2016 between PNMR, Westmoreland, SJCC and Zurich American Insurance Company	10.4 to PNMR's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016	1-32462 PNMR
10.26	Termination Agreement and Release of Zurich American Insurance Company dated as of August 3, 2016 among PNMR, Westmoreland, SJCC and Zurich American Insurance Company	10.1 to PNMR's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016	1-32462 PNMR
10.27	Note Purchase Agreement dated July 28, 2017 between PNM and the purchasers named therein (for eight series of senior unsecured notes)	10.1 to PNM's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017	1-6986 PNM
10.28	Credit Agreement, dated as of October 31, 2011 among PNM, the lenders party thereto, Wells Fargo Bank, National Association, as administrative agent and Union Bank, N.A., as syndication agent	10.2 to PNM's Current Report on Form 8-K filed October 31, 2011	1-6986 PNM
10.29	First Amendment to Credit Agreement dated January 18, 2012 among PNM, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent	10.2 to PNM's Annual Report on Form 10-K for the year ended December 31, 2011	1-6986 PNM
10.30	Second Amendment to Credit Agreement executed December 17, 2014 and fully effective as of January 22, 2015	10.2 to PNM's Current Report on Form 8-K filed December 17, 2014	1-6986 PNM
10.31	Third Amendment to Credit Agreement effective November 2, 2016 among PNM, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent	10.2 to PNM's Current Report on Form 8-K filed November 4, 2016	1-6986 PNM
10.32	Credit Agreement dated as of December 12, 2017 among PNM, the lenders identified therein, and U.S. Bank National Association, as administrative agent and BOKF, N.A. d/b/a Bank of Albuquerque, as syndication agent	10.1 to PNM's Current Report on Form 8-K filed December 12, 2017	1-6986 PNM
10.33	Term Loan Agreement dated as of July 20, 2017 among PNM, the lenders identified therein, and JPMorgan Chase Bank, N.A., as administrative agent	10.1 to PNM's Current Report on Form 8-K filed July 20, 2017	1-6986 PNM
10.34	Third Amended and Restated Credit Agreement dated as of September 25, 2017 among TNMP, the lenders identified therein and KeyBank National Association, as administrative agent	10.1 to TNMP's Current Report on Form 8-K filed September 27, 2017	2-97230 TNMP
10.35	Bond Purchase Agreement dated December 9, 2013 between TNMP and the purchasers named therein (for $80,000,000 4.03% First Mortgage Bonds, due 2024, Series 2014A)	10.1 to TNMP's Current Report on Form 8-K filed December 10, 2013	2-97230 TNMP

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10.36	Bond Purchase Agreement dated December 17, 2015 between TNMP and the purchasers named therein (for $60,000,000 3.53% First Mortgage Bonds, due 2026, Series 2016A)	10.1 to TNMP's Current Report on Form 8-K filed December 21, 2015	2-97230 TNMP
10.37	Bond Purchase Agreement dated June 14, 2017 between TNMP and the purchasers named therein (for $60,000,000 3.22% First Mortgage Bonds, due 2027, Series 2017A)	10.1 to PNM's Current Report on Form 8-K filed June 14, 2017	2-97230 TNMP
10.38**	PNMR 2014 Performance Equity Plan dated May 15, 2014	4.3 to PNMR's Form S-8 Registration Statement filed May 15, 2014	333-195974 PNMR
10.39**	First Amendment to PNMR 2014 Performance Equity Plan	99.1 to PNMR's Current Report on Form 8-K filed December 15, 2015	1-32462 PNMR
10.40**	Second Amendment to PNMR 2014 Performance Equity Plan effective January 1, 2017	10.2 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2016	1-32462 PNMR
10.41**	PNMR Second Amended and Restated Omnibus Performance Equity Plan dated May 19, 2009	4.1 to PNMR's Form S-8 Registration Statement filed May 20, 2009	333-159361 PNMR
10.42**	Amendment dated May 17, 2011 to PNMR's Second Amended and Restated	10.1 to PNMR's Current Report Form 8-K filed May	1-32462

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	Omnibus Performance Equity Plan	20, 2011	PNMR
10.43**	Second Amendment executed March 28, 2012 to the PNMR Second Amended and Restated Omnibus Performance Equity Plan	10.6 to PNMR's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012	1-32462 PNMR
10.44**	Third Amendment (approved by PNMR shareholders on May 15, 2012) to the PNMR Second Amended and Restated Omnibus Performance Equity Plan	10.1 to PNMR's Current Report on Form 8-K filed May 17, 2012	1-32462 PNMR
10.45**	Fourth Amendment to the PNMR Second Amended and Restated Omnibus Performance Equity Plan effective January 1, 2017	10.3 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2016	1-32462 PNMR
10.46**	PNMR 2016 Officer Annual Incentive Plan dated March 22, 2016	10.6 to PNMR's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016	1-32462 PNMR
10.47**	PNMR 2017 Officer Annual Incentive Plan dated March 29, 2017	10.1 to PNMR's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017	1-32462 PNMR
10.48**	PNMR 2017 Long-Term Incentive Plan dated March 31, 2017	10.2 to PNMR's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017	1-32462 PNMR
10.49**	PNMR 2016 Long-Term Incentive Plan dated March 22, 2016	10.5 to PNMR's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016	1-32462 PNMR
10.50**	PNMR 2015 Long-Term Incentive Plan dated March 20, 2015	10.2 to PNMR's Quarterly Report on Form 10-Q for the quarter ended March 31, 2015	1-32462 PNMR
10.51**	Master Amendment to Long-Term Performance Equity Plan executed January 10, 2017	10.4 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2016	1-32462 PNMR
10.52**	PNMR Director Deferred Stock Rights Program effective December 1, 2017	10.1 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2017	1-32462 PNMR

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10.53**	Form of Stock Option Award Agreement for non-qualified stock options granted under performance equity plan in 2010	10.3 to PNMR's Current Report on Form 8-K filed May 26, 2009	1-32462 PNMR
10.54**	Form of the award agreement for non-qualified stock options granted under performance equity plan in 2007-2009	10.2 to PNMR's Current Report on Form 8-K filed February 16, 2007	1-32462 PNMR
10.55**	Employee Retention Agreement executed December 9, 2014 between PNMR and Charles N. Eldred	10.2 to PNMR's Annual Report on For 10-K for the year ended December 31, 2014	1-32462 PNMR
10.56**	Employee Retention Agreement executed March 4, 2015 between PNMR and Patricia K. Collawn	10.3 to PNMR's Quarterly Report on Form 10-Q for the quarter ended March 31, 2015	1-32462 PNMR
10.57**	Acknowledgement Form for officer restricted stock rights and awards granted under the PNMR 2014 Performance Equity Plan dated May 15, 2014	10.4.2 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2014	1-32462 PNMR
10.58**	2017 Director Compensation Summary (2018 annual retainer is the same as the 2017 annual retainer)	10.1 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2016	1-32462 PNMR
10.59**	Acknowledgement Form for stock option awards granted to directors under the Second Amended and Restated Omnibus Performance Equity Plan dated May 19, 2009, as amended	10.3 to PNMR's Current Report on Form 8-K filed March 1, 2011	1-32462 PNMR
10.60**	Acknowledgment Form with attached Terms and Conditions for restricted stock rights awards granted to directors from 2014 - 2017 under the PNMR 2014 Performance Equity Plan dated May 15, 2014	10.4.3 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2014	1-32462 PNMR
10.61**	Acknowledgement Form with attached Terms and Conditions for restricted stock rights granted to directors on and after 2018 under the PNMR 2014 Performance Equity Plan dated May 15, 2014	10.5 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2017	1-32462 PNMR
10.62**	PNMR Executive Spending Account Plan (amended and restated effective January 1, 2011)	10.4 to PNMR's Current Report on Form 8-K filed March 1, 2011	1-32462 PNMR
10.63**	First Amendment to PNMR Executive Spending Account Plan effective January 1, 2011	10.7 to PNMR's Current Report on Form 10-K for the year ended December 31, 2016	1-32462 PNMR
10.64**	Second Amendment to PNMR Executive Spending Account executed December 13, 2017	10.2 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2017	1-32462 PNMR
10.65**	PNMR Executive Savings Plan II (amended and restated effective January 1, 2015)	10.1.2 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2014	1-32462 PNMR
10.66**	First Amendment to PNMR Executive Savings Plan II executed April 15, 2016	10.7 to PNMR's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016	1-32462 PNMR
10.67**	Summary of PNMR Officer Paid Time Off Program	10.6 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2016	1-32462 PNMR

10.68**	PNMR Annual Executive Physical Exam Program Wraparound Plan Document effective as of January 1, 2014	10.7 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2013	1-32462 PNMR

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10.69**	PNMR Non-Union Severance Pay Plan effective August 1, 2007 (amended and restated)	10.3 to PNMR's Quarterly Report on Form 10-Q for the quarter ended September 30, 2007	1-32462 PNMR
10.70**	First Amendment to the PNMR Non-Union Severance Pay Plan executed November 20, 2008	10.3 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2008	1-32462 PNMR
10.71**	Second Amendment (executed March 27, 2012) to PNMR Non-Union Severance Pay Plan	10.8 to PNMR's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012	1-32462 PNMR
10.72**	Third Amendment (executed November 11, 2015) to PNMR Non-Union Severence Pay Plan	10.6 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2017	1-32462 PNMR
10.73**	PNMR Officer Retention Plan executed March 28, 2012 as amended and restated effective as of January 1, 2012	10.7 to PNMR's Quarterly Report in Form 10-Q for the quarter ended March 31, 2012	1-32462 PNMR
10.74**	PNMR Officer Life Insurance Plan dated April 28, 2004	10.24.1 to PNMR's Quarterly Report on Form 10-Q for the quarter ended March 31, 2004	333-32170 PNMR
10.75**	First Amendment to PNMR Officer Life Insurance Plan dated December 16, 2004	10.27 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2004.	333-32170 PNMR
10.76**	Second Amendment to PNMR Officer Life Insurance Plan executed April 15, 2007	10.5 to PNMR's Quarterly Report on Form 10-Q for the quarter ended September 30, 2007	1-32462 PNMR
10.77**	Third Amendment to the PNMR Officer Life Insurance Plan effective January 1, 2009	10.10 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2008	1-32462 PNMR
10.78**	Fourth Amendment to the PNMR Officer Life Insurance Plan effective January 1, 2009	10.15 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2008	1-32462 PNMR
10.79**	Fifth Amendment to the PNMR Officer Life Insurance Plan executed December 16, 2011	10.5 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2011	1-32462 PNMR
10.80**	PNMR Officers Long Term Disability Coverage Description for Prudential Policy effective January 1, 2012	10.8 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2016	333-32170 PNMR
10.81**	Form of Indemnity Agreement for PNMR officers and directors	10.9 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2016	1-32462 PNMR
10.82	Supplemental Indenture of Lease dated as of July 19, 1966 between PNM and other participants in the Four Corners Project and the Navajo Indian Tribal Council	4-D to PNM's Registration Statement No. 2-26116	2-26116 PNM
10.83	Amendment and Supplement No. 1 to Supplemental and Additional Indenture of Lease dated April 25, 1985 between the Navajo Tribe of Indians and Arizona Public Service Company, El Paso Electric Company, Public Service Company of New Mexico, Salt River project Agricultural Improvement and Power District, Southern California Edison Company, and Tucson Electric Power Company (refiled)	10.1.1 to PNM's Annual Report on Form 10-K for year ended December 31, 1995	1-6986 PNM
10.84	Amendment and Supplement No. 2 to Supplemental and Additional Indenture of Lease with the Navajo Nation dated March 7, 2011	10.1 to PNM's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011	1-6986 PNM

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10.85	Amendment and Supplement No. 3 to Supplemental and Additional Indenture of Lease with the Navajo Nation dated March 7, 2011	10.2 to PNM's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011	1-6986 PNM
10.86	Coal Supply Agreement dated July 1, 2015 between Westmoreland Coal Company and PNM	10.1 to PNM's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015	1-6986 PNM
10.87	Amendment No. 1 to Coal Supply Agreement dated November 1, 2017 between Westmoreland Coal Company and PNM	10.4 to PNM's Annual Report on Form 10-K for the year ended December 31, 2017	1-6986 PNM
10.88	Underground Coal Sales Agreement Termination and Mutual Release Agreement dated July 1, 2015 among San Juan Coal Company, BHP Billiton New Mexico Coal, Inc., PNM and Tucson Electric Power Company	10.2 to PNM's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015	1-6986 PNM
10.89	San Juan Project Restructuring Agreement executed as of July 31, 2015 among PNM, Tucson Electric Coal Company, The City of Farmington, New Mexico, M-S-R Public Power Agency, The Incorporated County of Los Alamos, New Mexico, Southern California Public Power Authority, City of Anaheim, Utah Associated Municipal Power Systems, Tri-State Generation and Transmission Association, Inc., and	10.3 to PNM's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015	1-6986 PNM

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	PNMR Development and Management Corporation		
10.90	Restructuring Amendment Amending and Restating the Amended and Restated San Juan Project Participation Agreement made as of July 31, 2015 among PNM, Tucson Electric Power Company, The City of Farmington, New Mexico, M-S-R Public Power Agency, The Incorporated County of Los Alamos, New Mexico, Southern California Public Power Authority, City of Anaheim, Utah Associated Municipal Power Systems, Tri-State Generation and Transmission Association, Inc., and PNMR Development and Management Corporation	10.4 to PNM's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015	1-6986 PNM
10.91	Exit Date Amendment Amending and Restating the Amended and Restated San Juan Project Participation Agreement made as of July 31, 2015 among PNM, Tucson Electric Power Company, The City of Farmington, New Mexico, The Incorporated County of Los Alamos, New Mexico, Utah Associated Municipal Power Systems, and PNMR Development and Management Corporation	10.5 to PNM's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015	1-6986 PNM
10.92	New Exit Date Amendment Amending and Restating the Amended and Restated San Juan Project Participation Agreement made as of September 1, 2017 among PNM, Tucson Electric Power Company, The City of Farmington, New Mexico, The Incorporated County of Los Alamos, New Mexico and Utah Associated Municipal Power Systems	10.1 to PNM's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017	1-6986 PNM
10.93	Arizona Nuclear Power Project Participation Agreement among PNM and Arizona Public Service Company, Salt River Project Agricultural Improvement and Power District, Tucson Gas & Electric Company and El Paso Electric Company, dated August 23, 1973	5-T to PNM's Registration Statement No. 2-50338	2-50338 PNM
10.94	Amendments No. 1 through No. 6 to Arizona Nuclear Power Project Participation Agreement	10.8.1 to PNM's Annual Report on Form 10-K for year ended December 31, 1991	1-6986 PNM
10.95	Amendment No. 7 effective April 1, 1982, to the Arizona Nuclear Power Project Participation Agreement (refiled)	10.8.2 to PNM's Annual Report on Form 10-K for year ended December 31, 1991	1-6986 PNM

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10.96	Amendment No. 8 effective September 12, 1983, to the Arizona Nuclear Power Project Participation Agreement (refiled)	10.58 to PNM's Annual Report on Form 10-K for year ended December 31, 1993	1-6986 PNM
10.97	Amendment No. 9 to Arizona Nuclear Power Project Participation Agreement dated as of June 12, 1984 (refiled)	10.8.4 to PNM's Annual Report of the Registrant on Form 10-K for year ended December 31, 1994	1-6986 PNM
10.98	Amendment No. 10 dated as of November 21, 1985 and Amendment No. 11 dated as of June 13, 1986 and effective January 10, 1987 to Arizona Nuclear Power Project Participation Agreement (refiled)	10.8.5 to PNM's Annual Report of the Registrant on Form 10-K for year ended December 31, 1995	1-6986 PNM
10.99	Amendment No. 12 to Arizona Nuclear Power Project Participation Agreement dated June 14, 1988, and effective August 5, 1988	19.1 to PNM's Quarterly Report on Form 10-Q for the quarter ended September 30, 1990	1-6986 PNM
10.100	Amendment No. 13 to the Arizona Nuclear Power Project Participation Agreement dated April 4, 1990, and effective June 15, 1991	10.8.10 to PNM's Annual Report on Form 10-K for the year ended December 31, 1990	1-6986 PNM
10.101	Amendment No. 14 to the Arizona Nuclear Power Project Participation Agreement effective June 20, 2000	10.8.9 to PNM's Annual Report on Form 10-K for the year ended December 31, 2000	1-6986 PNM
10.102	Amendment No. 15 to the Arizona Nuclear Power Project Participation Agreement dated November 29, 2010 and effective January 13, 2011	10.1 to PNM's Current Report on Form 8-K filed March 1, 2011	1-6986 PNM
10.103	Amendment No. 16, effective as of April 28, 2014, to the Arizona Nuclear Power Project Participation Agreement	10.3 to PNM's Quarterly Report on Form 10-Q for the quarter ended March 31, 2014	1-6986 PNM
10.104*	Facility Lease dated as of December 16, 1985 between The First National Bank of Boston, as Owner Trustee, and PNM (Unit 1 transaction) together with Amendments No. 1, 2 and 3 thereto (refiled)	10.18 to PNM's Annual Report on Form 10-K for year ended December 31, 1995	1-6986 PNM
10.105	Facility Lease dated as of July 31, 1986, between the First National Bank of Boston, as Owner Trustee, and PNM (Unit 1 transaction) together with Amendments No. 1, 2 and 3 thereto (refiled)	10.19 to PNM's Annual Report on Form 10-K for year ended December 31, 1996	1-6986 PNM
10.106	Facility Lease dated as of December 15, 1986, between The First National Bank of Boston, as Owner Trustee, and PNM (Unit 1 Transaction) together with Amendment No. 1 thereto (refiled)	10.21 to PNM's Annual Report on Form 10-K for year ended December 31, 1996	1-6986 PNM
10.107*	Amendment No. 4 dated as of December 11, 2013 to Facility Lease dated as of December 16, 1985 as heretofore amended, between U.S. Bank National Association (ultimate successor to The First National Bank of Boston), as Owner Trustee, and PNM (Unit 1 transaction)	10.3 to PNM's Annual Report on Form 10-K for year ended December 31, 2013	1-6986 PNM
10.108	Facility Lease dated as of December 15, 1986, between The First National Bank of Boston, as Owner Trustee, and PNM (Unit 2 Transaction) together with Amendment No. 1 thereto (refiled)	10.22 to PNM's Annual Report on Form 10-K for year ended December 31, 1996	1-6986 PNM

10.109	Amendment No. 2 dated as of March 18, 2014, to the Facility Lease dated December 15, 1986, as heretofore amended, between U.S. Bank National Association, not in its individual capacity, but solely as Owner Trustee under a Trust Agreement, dated as of December 15, 1986, with PV2-PNM December 35 Corporation, Lessor, and PNM, Lessee	10.1 to PNM's Current Report on Form 8-K filed March 18, 2014	1-6986 PNM

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10.110	Master Decommissioning Trust Agreement for Palo Verde Nuclear Generating Station dated March 15, 1996, between PNM and Mellon Bank, N.A.	10.68 to PNM's Quarterly Report on Form 10-Q for the quarter ended March 31, 1996	1-6986 PNM
10.111	Amendment Number One to the Master Decommissioning Trust Agreement for Palo Verde Nuclear Generating Station dated January 27, 1997, between PNM and Mellon Bank, N.A.	10.68.1 to PNM's Annual Report on Form 10-K for year ended December 31, 1997	1-6986 PNM
10.112	Amendment Number Two to the Master Decommissioning Trust Agreement for Palo Verde Nuclear Generating Station between PNM and Mellon Bank, N.A.	10.68.2 to PNM's Annual Report on Form 10-K for year ended December 31, 2003	1-6986 PNM
10.113	Stipulation in the matter of PNM's transition plan Utility Case No. 3137, dated October 10, 2002 as amended by Amendment to Stipulated Agreement dated October 18, 2002	10.86 to PNM's Annual Report on Form 10-K for the year ended December 31, 2002	1-6986 PNM
10.114	Stipulation dated February 28, 2005 in NMPRC Case No. 04-00315-UT regarding the application of PNMR and TNMP for approval of the TNP acquisition	10.134 to PNMR's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005	1-32462 PNMR/ TNMP
Subsidiaries			
21	Certain subsidiaries of PNMR	21 to PNMR's Annual Report on Form 10-K for the year ended December 31, 2017	1-32462 PNMR
Additional Exhibits			
99.1*	Participation Agreement dated as of December 16, 1985, among the Owner Participant named therein, First PV Funding Corporation, The First National Bank of Boston, in its individual capacity and as Owner Trustee (under a Trust Agreement dated as of December 16, 1985 with the Owner Participant), Chemical Bank, in its individual capacity and as Indenture Trustee (under a Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of December 16, 1985 with the Owner Trustee), and PNM (Unit 1 transaction), including Appendix A definitions, together with Amendment No. 1 dated July 15, 1986 and Amendment No. 2 dated November 18, 1986 (refiled)	99.2 to PNM's Annual Report on Form 10-K for year ended December 31, 1995	1-6986 PNM
99.2	Participation Agreement dated as of July 31, 1986, among the Owner Participant named herein, First PV Funding Corporation, The First National Bank of Boston, in its individual capacity and as Owner Trustee (under a Trust Agreement dated as of July 31, 1986, with the Owner Participant), Chemical Bank, in its individual capacity and as Indenture Trustee (under a Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of July 31, 1986, with the Owner Trustee), and Public Service Company of New Mexico, including Appendix A definitions together with Amendment No. 1 thereto (refiled)	99.5 to PNM's Annual Report on Form 10-K for year ended December 31, 1996	1-6986 PNM
99.3	Participation Agreement dated as of December 15, 1986, among the Owner Participant named therein, First PV Funding Corporation, The First National Bank of Boston, in its individual capacity and as Owner Trustee (under a Trust Agreement dated as of December 15, 1986, with the Owner Participant), Chemical Bank, in its individual capacity and as Indenture Trustee (under a Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of December 15, 1986, with the Owner Trustee), and Public Service Company of New Mexico, including Appendix A definitions (Unit 1 Transaction) (refiled)	99.11 to PNM's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997	1-6986 PNM

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99.4	Participation Agreement dated as of December 15, 1986, among the Owner Participant named therein, First PV Funding Corporation, The First National Bank of Boston, in its individual capacity and as Owner Trustee (under a Trust Agreement dated as of December 15, 1986, with the Owner Participant), Chemical Bank, in its individual capacity and as Indenture Trustee (under a Trust Indenture, Mortgage, Security Agreement and Assignment of Rents dated as of December 15, 1986, with the Owner Trustee), and Public Service Company of New Mexico, including Appendix A definitions (Unit 2 Transaction) (refiled)	99.14 to PNM's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997	1-6986 PNM
99.5	Agreement for the Sale and Purchase of Wastewater Effluent, dated November 13, 2000, among the City of Tolleson, Arizona Public Service Company and Salt River Project Agricultural Improvement and Power District	99.19 to PNM's Annual Report on Form 10-K for year ended December 31, 2013	1-6986 PNM
99.6	Municipal Effluent Purchase and Sale Agreement dated April 23, 2010 between Cities	10.6 to PNM's Quarterly Report on Form 10-Q for	1-6986

of Phoenix, Mesa, Tempe, Scottsdale and Glendale, Arizona municipal corporations; and APS, SRP, acting on behalf of themselves and EPE, SCE, PNM, SCPPA, and Los Angeles Department of Water and Power	the quarter ended March 31, 2010	PNM

* One or more additional documents, substantially identical in all material respects to this exhibit, have been entered into, relating to one or more additional sale and leaseback transactions. Although such additional documents may differ in other respects (such as dollar amounts and percentages), there are no material details in which such additional documents differ from this exhibit.

** Designates each management contract or compensatory plan or arrangement required to be identified pursuant to paragraph 3 of Item 15(a) of Form 10-K.

‡ Certain instruments defining the rights of holders of long-term debt of the registrants included in the financial statements of registrants filed herewith have been omitted because the total amount of securities authorized thereunder does not exceed 10% of the total assets of registrants. The registrants hereby agree to furnish a copy of any such omitted instrument to the SEC upon request.

ITEM 16. FORM 10-K SUMMARY

None.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PNM RESOURCES, INC.
(Registrant)

Date: March 1, 2018 By /s/ P. K. Collawn
P. K. Collawn
Chairman, President, and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Capacity	Date
/s/ P. K. Collawn P. K. Collawn Chairman, President, and Chief Executive Officer	Principal Executive Officer and Director	March 1, 2018
/s/ C. N. Eldred C. N. Eldred Executive Vice President and Chief Financial Officer	Principal Financial Officer	March 1, 2018
/s/ J. D. Tarry J. D. Tarry Vice President, Finance and Controller	Principal Accounting Officer	March 1, 2018
/s/ N.P. Becker N. P. Becker	Director	March 1, 2018
/s/ E. R. Conley E. R. Conley	Director	March 1, 2018
/s/ A. J. Fohrer A. J. Fohrer	Director	March 1, 2018
/s/ S. M. Gutierrez S. M. Gutierrez	Director	March 1, 2018
/s/ M. T. Mullarkey M. T. Mullarkey	Director	March 1, 2018

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/s/ D. K. Schwanz D. K. Schwanz	Director	March 1, 2018
/s/ B. W. Wilkinson B. W. Wilkinson	Director	March 1, 2018

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PUBLIC SERVICE COMPANY OF NEW MEXICO
(Registrant)

Date: March 1, 2018 By /s/ P. K. Collawn
P. K. Collawn
President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	**Capacity**	**Date**
/s/ P. K. Collawn P. K. Collawn President and Chief Executive Officer	Principal Executive Officer and Chairman of the Board	March 1, 2018
/s/ C. N. Eldred C. N. Eldred Executive Vice President and Chief Financial Officer	Principal Financial Officer and Director	March 1, 2018
/s/ J. D. Tarry J. D. Tarry Vice President, Finance and Controller	Principal Accounting Officer	March 1, 2018
/s/ R. N. Darnell R. N. Darnell	Director	March 1, 2018
/s/ C. M. Olson C. M. Olson	Director	March 1, 2018

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TEXAS-NEW MEXICO POWER COMPANY
(Registrant)

Date: March 1, 2018 By /s/ P. K. Collawn
P. K. Collawn
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

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Signature	Capacity	Date
/s/ P. K. Collawn P. K. Collawn Chief Executive Officer	Principal Executive Officer and Chairman of the Board	March 1, 2018
/s/ C. N. Eldred C. N. Eldred Executive Vice President and Chief Financial Officer	Principal Financial Officer and Director	March 1, 2018
/s/ J. D. Tarry J. D. Tarry Vice President, Finance and Controller	Principal Accounting Officer	March 1, 2018
/s/ R. N. Darnell R. N. Darnell	Director	March 1, 2018
/s/ C. M. Olson C. M. Olson	Director	March 1, 2018
/s/ J. N. Walker J. N. Walker	Director	March 1, 2018

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Section 2: EX-10.1 (EXHIBIT 10.1)

Exhibit 10.1

PNM RESOURCES, INC.
DIRECTOR DEFERRED RESTRICTED
STOCK RIGHTS PROGRAM

This PNM Resources, Inc. Director Deferred Restricted Stock Rights Program (the "Program") is adopted by the Board of Directors (the "Board") of PNM Resources, Inc. (the "Company") pursuant to the PNM Resources, Inc. 2014 Performance Equity Plan (the "Plan"). The Program is effective as of December 1, 2017.

1. **Background**. Nonemployee Directors are compensated for their services, in part, by the receipt of Restricted Stock Rights. Unless the Board determines otherwise, the Grant Date for the Restricted Stock Rights made to Nonemployee Directors is the Annual Meeting Date. Currently, Restricted Stock Rights granted to Nonemployee Directors vest on the first anniversary of the Grant Date and payment in the form of Company Stock is made for these Restricted Stock Rights following vesting. Tax is due when the payment is made.

The purpose of the Program is to allow Nonemployee Directors to defer receipt of payment (and taxation) of Restricted Stock Rights granted under the Plan as described below. This Program applies only to grants of Restricted Stock Rights made on and after May 2018. All Nonemployee Directors are eligible to participate in the Program. If a Nonemployee Director chooses to not participate in the Program, the Restricted Stock Rights will be paid to the Nonemployee Director at such time as determined by the Board, which is currently following vesting.

2. **Deferral of Restricted Stock Rights**. Pursuant to the Program, a Nonemployee Director may make an annual election to defer receipt of payment for vested Restricted Stock Rights to a future date selected by the Nonemployee Director. The election to defer the payment is made by filing a signed election form (that will be provided by the Company) by December 31 of the calendar year prior to the year for which the election relates. The election will become irrevocable as of the relevant December 31. The election will only be effective for the calendar year to which it relates. A new election will be required if the Nonemployee Director wants to participate in the Program in any later calendar year.

For the calendar year in which an individual first becomes a Nonemployee Director, he or she may elect to defer receipt of his or her Restricted Stock Rights by filing a signed election form provided by the Company prior to the first day on which he or she becomes a Nonemployee Director. The election form shall be conditional on his or her actually becoming a Nonemployee Director and it shall become irrevocable on the day prior to the first day on which the Nonemployee Director becomes a member of the Board.

3. **Payment for Restricted Stock Rights**. As in the past, payment of Restricted Stock Rights will be in the form of Company Stock. If a Director chooses to participate in this Program, a Director may elect among three payment timing alternatives:

- A Director may elect to have the payment made in May of a year specified by the Nonemployee Director. In no event may the payment be made later than the fifth anniversary of the Nonemployee Director's Termination of Service as a Nonemployee Director.

- Alternatively, a Director may elect to have the payment made within sixty (60) days following the Director's Termination of Service as a Nonemployee Director.

- As a third alternative, a Director may elect to have the payment made on a specified anniversary (not to exceed the fifth anniversary) of the Nonemployee Director's Termination of Service as a Nonemployee Director.

If a Nonemployee Director elects to participate in the Program, but fails to make an election as to the time of payment of the Director's Restricted Stock Rights, such payment will be made within sixty (60) days following the Director's Termination of Service as a Nonemployee Director. If the Nonemployee Director dies prior to receiving all of the Nonemployee Director's Restricted Stock Rights under the Program, the Director's remaining Restricted Stock Rights will be paid within ninety (90) days following the Nonemployee Director's death to the Director's beneficiary as described in Section 12.2 of the Plan. If the Company is in a blackout period at the time a payment would otherwise be made, payment of the Restricted Stock Rights will be delayed until a later date after the blackout period ends. This date is the "Payment Date."

4. **No Dividend Equivalents**. A Nonemployee Director who elects to defer payment of his or her vested Restricted Stock Rights will not be entitled to receive payment equal to the amount of dividends, if any, that he or she would have received if he or she had directly owned the Stock to which the vested Restricted Stock Rights relate from the date of vesting to the Payment Date.

5. **Amendment and Termination**. The Board reserves the right to modify, amend or terminate this Program at any time and from time to time. Any such amendment, modification or termination, however, shall be subject to the requirements of Article 15 of the Plan, to the extent that it is applicable.

6. **Definitions**. When a word or phrase appears in this Program document with the initial letter capitalized and the word or phrase does not begin a sentence, the word or phrase shall generally be given the meaning ascribed to it in the Plan, unless a clearly different meaning is required by the context in which the word or phrase is used or a different meaning is specifically provided in this Program document.

7. **Compliance with the Plan**. This Program at all times will be subject to the terms and conditions of the Plan and any related Award Document. The terms and provisions of the Plan and any related Award Document, as amended from time to time, are hereby incorporated herein by reference. The Board shall have the sole and complete discretion with respect to the interpretation of the Program. The Board and/or the Compensation and Human Resources Committee shall have the sole and complete discretion with respect to the interpretation of the Plan. The decisions of the majority of the Board shall be final and binding upon a Nonemployee Director and the Company. In the event of any conflict between the terms and conditions of the Program and the Plan, the provisions of the Plan shall control.

8. **Section 409A Compliance**. This Program shall be administered in accordance with the requirements of the Plan, including Section 18.3. This Program is intended to be

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administered in compliance with Section 409A of the Code and each provision of the Program shall be interpreted, to the extent possible, to comply with Section 409A of the Code.

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Section 3: EX-10.2 (EXHIBIT 10.2)

Exhibit 10.2

SECOND AMENDMENT
TO THE
PNM RESOURCES, INC.
EXECUTIVE SPENDING ACCOUNT PLAN

Effective as of January 1, 1980, Public Service Company of New Mexico ("PNM") adopted the Amended and Restated Medical Reimbursement Plan of Public Service Company of New Mexico (the "MERP"). Sponsorship of the MERP was subsequently transferred from PNM to PNM Resources, Inc. (the "Company") on November 30, 2002. Effective January 1, 2002, the Company established the Executive Spending Account (the "ESA"). Effective December 1, 2002, the Company merged the MERP with and into the ESA and named the combined program the "PNM Resources, Inc. Executive Spending Account Plan" (the "Plan"). The Plan has been amended and restated on a number of occasions, with the most recent restatement being effective as of January 1, 2011. The

Plan was subsequently amended on one occasion. By this instrument, the Company now desires to: 1) clarify that the Plan does not reimburse individual health insurance premiums; and 2) clarify that the Plan has been operated on an integrated basis beginning January 1, 2014.

1. This Second Amendment shall be effective as of January 1, 2014, unless otherwise specifically provided.

2. Article 2 of the Plan ("Defined Terms"), as amended by the First Amendment, is hereby amended by restating the Covered Expense section to read as follows:

Covered Expense: Expenses incurred by the Participant or a Dependent during the current or preceding Paycheck Year, while covered by the Plan, for any of the following: (1) income tax preparation; (2) estate planning (including preparation of wills and trusts); (3) financial counseling, but excluding brokerage fees or commissions; (4) financial management services (this would include, for example, the services provided by a management firm that manages your real estate investments); (5) premiums covering the Participant and his or her Dependents for health

care (but only if such health care is provided under an employer group health plan providing "minimum value" pursuant to Code Section 36B(c)(2)(C)(ii) and not an individual health insurance policy, such as an individual Medicare supplement policy), accident, disability, life, dependent life, and/or supplemental insurance (similar to AFLAC), whether paid for by the Participant as a private party or deducted from the Participant's salary under a PNM Resources benefit program; (6) premiums for home, auto, title or personal liability umbrella insurance; (7) premiums covering the Participant or Family Members for long-term care insurance, whether paid for by the Participant as a private party or deducted from the Participant's salary under a PNM Resources benefit program; or (8) reasonable transportation and lodging expenses in connection with the Participant's health care (but only if such health care is provided under the PNM Resources, Inc. Annual Executive Physical Exam Program, which uses the "minimum value required method" of integration outlined in Internal Revenue Service Notice 2013-54), financial planning and real estate management, including estate planning, financial counseling and financial management services as described in items (2), (3) and (4). An expense that qualifies as a Covered Expense pursuant to items (1) through (8) above, is "incurred" as of the date on which you are billed for the expense or premium.

3. Article 4 of the Plan ("Eligibility and Participation Requirements"), as amended by the First Amendment, is hereby amended by restating the Eligibility section to read as follows:

Eligibility: You are eligible to participate in the Plan if you are an Employee of the Company and you are a vice-president or higher-ranking officer and you are classified and coded as an officer pursuant to the Company's compensation system. Your Spouse and "Dependents," as defined in Article 2 are eligible to participate in the Plan if you are.

As required by the "minimum value required method" of integration outlined in Internal Revenue Service Notice 2013- 54, you may opt out of and waive future benefits/reimbursements for "health care" from the Plan at least annually, and as provided in Article 4, your participation in the Plan terminates as of the date you terminate employment, if not sooner. "Health care" for the purpose of this paragraph is as

defined in clauses (5) and (8) of the "Covered Expense" section in Article 2 of the Plan.

4. This Second Amendment amends only the provisions of the Plan as noted above, and those provisions not expressly amended shall be considered in full force and effect. Notwithstanding the foregoing, this Second Amendment shall supersede the provisions of the Plan to the extent those provisions are inconsistent with the provisions and intent of this Second Amendment.

IN WITNESS WHEREOF, PNM Resources has caused this Second Amendment to be executed as of this 13th day of December , 2017.

PNM RESOURCES, INC.

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By: /s/ Patrick V. Apodaca

Its: SVP and General Counsel

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Section 4: EX-10.3 (EXHIBIT 10.3)

Exhibit 10.3

EXECUTION COPY

FIRST AMENDMENT TO TERM LOAN AGREEMENT

THIS FIRST AMENDMENT TO TERM LOAN AGREEMENT (this "Amendment") is dated as of November 28, 2017 among PNM RESOURCES, INC., a New Mexico corporation (the "Borrower"), the Lenders party hereto and JPMORGAN CHASE BANK, N.A., as Administrative Agent for the Lenders (in such capacity, the "Administrative Agent"). Capitalized terms used herein and not otherwise defined shall have the meanings ascribed thereto in the Loan Agreement (as defined below).

R E C I T A L S

WHEREAS, the Borrower, the Lenders party thereto and the Administrative Agent are parties to that certain Term Loan Agreement, dated as of December 21, 2016 (as amended or modified from time to time, the "Loan Agreement");

WHEREAS, the Borrower has requested a modification to the Loan Agreement as described below; and

WHEREAS, the Administrative Agent and the Lenders party hereto are willing to agree to such modification, subject to the terms set forth herein as more fully set forth below.

NOW, THEREFORE, in consideration of the premises and the mutual covenants contained herein, and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the parties hereto agree as follows:

A G R E E M E N T

1. Amendment to Loan Agreement. The following definition of "Applicable Percentage" in Section 1.1 of the Loan Agreement is amended and restated in its entirety to read as follows:

"*Applicable Percentage*" means, (a) for Eurodollar Loans, (i) 0.95% from the Closing Date to and including November 30, 2017, (ii) 0.775% from December 1, 2017 to and including September 30, 2018 and (iii) 0.95% from October 1, 2018 to the Maturity Date and (b) for Base Rate Loans, 0.00%.

2. Effectiveness. This Amendment shall be effective as of the date first written above; provided that on or before such date the Administrative Agent shall have received (i) copies of this Amendment duly executed by the Borrower, the Administrative Agent and the Lenders and (ii) payment of the fees and expenses of counsel for the Administrative Agent in connection with this Amendment.

3. Ratification of Loan Agreement. The term "Loan Agreement" as used in each of the Loan Documents shall hereafter mean the Loan Agreement as amended and modified by this Amendment and as amended and modified from time to time hereafter. Except as herein specifically agreed, the Loan Agreement, as amended by this Amendment, is hereby ratified and confirmed and shall remain in full force and effect according to its terms. Each party hereto acknowledges and consents to the modifications set forth herein and agrees that, other than as explicitly set forth in Section 1 above, this Amendment does not impair, reduce or limit any of its obligations under the Loan Documents (including, without limitation,

the indemnity obligations set forth therein) and that, after the date hereof, this Amendment shall constitute a Loan Document.

4. Authority/Enforceability. The Borrower represents and warrants as follows:

(a) It has taken all necessary action to authorize the execution, delivery and performance of this Amendment.

(b) This Amendment has been duly executed and delivered by the Borrower and constitutes the Borrower's legal, valid and binding obligations, enforceable in accordance with its terms, except as such enforceability may be limited by Debtor Relief Laws or similar laws affecting creditors' rights generally or by general principles of equity.

(c) No consent, approval, authorization or order of, or filing, registration or qualification with, any court or Governmental Authority or third party is required in connection with the execution, delivery or performance by the Borrower of this Amendment that has not been obtained or completed.

5. Representations and Warranties. The Borrower represents and warrants to the Lenders that (a) the representations and warranties of the Borrower set forth in Section 6 of the Loan Agreement are true and correct as of the date hereof, unless they specifically refer to an earlier date, (b) no event has occurred and is continuing which constitutes a Default or an Event of Default, and (c) it has no claims, counterclaims, offsets, credits or defenses to its obligations under the Loan Documents, or to the extent it has any, they are hereby released in consideration of the Lenders party hereto entering into this Amendment.

6. No Conflicts. The Borrower represents and warrants that the execution and delivery of this Amendment, the consummation of the transactions contemplated herein and in the Loan Agreement (before and after giving effect to this Amendment), and the performance of and compliance with the terms and provisions hereof by the Borrower will not (a) violate, contravene or conflict with any provision of its articles or certificate of incorporation, bylaws or other organizational or governing document, (b) violate, contravene or conflict with any law, rule, regulation (including, without limitation, Regulation U and Regulation X), order, writ, judgment, injunction, decree or permit applicable to the Borrower, (c) violate, contravene or conflict with contractual provisions of, or cause an event of default under, any indenture, loan agreement, mortgage, deed of trust, contract or other agreement or instrument to which the Borrower is a party or by which it or its properties may be bound, the violation of which would have or would be reasonably expected to have a Material Adverse Effect or (d) result in or require the creation of any Lien upon or with respect to the Borrower's properties.

7. Counterparts/Telecopy. This Amendment may be executed in any number of counterparts, each of which when so executed and delivered shall be an original, but all of which shall constitute one and the same instrument. Delivery of executed counterparts by telecopy or by electronic format (.pdf) shall be effective as an original.

8. GOVERNING LAW. THIS AMENDMENT AND THE RIGHTS AND OBLIGATIONS OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK.

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Each of the parties hereto has caused a counterpart of this Amendment to be duly executed and delivered as of the date first above written.

BORROWER:

PNM RESOURCES, INC.,
a New Mexico corporation

By: /s/ Elisabeth Eden
Name: Elisabeth Eden
Title: Vice President and Treasurer

LENDER:

JPMORGAN CHASE BANK, N.A.,
individually in its capacity as a Lender and in its capacity as Administrative Agent

By: /s/ Helen D. Davis
Name: Helen D. Davis
Title: Executive Director

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Section 5: EX-10.4 (EXHIBIT 10.4)

Exhibit 10.4

AMENDMENT NO. 1 TO COAL SUPPLY AGREEMENT

THIS AMENDMENT NO. 1 TO COAL SUPPLY AGREEMENT ("Amendment No. 1"), dated as of November 1, 2017, is by and between **WESTMORELAND COAL COMPANY**, a Delaware corporation ("Westmoreland") and **PUBLIC SERVICE COMPANY OF NEW MEXICO**, a New Mexico corporation ("Utility" and along with Westmoreland, referred to herein individually as a "Party" and collectively as the "Parties").

RECITALS

WHEREAS, Utility and Westmoreland are parties to that certain Coal Supply Agreement dated as of July 1, 2015, (the "CSA") pursuant to which Westmoreland's wholly-owned subsidiary San Juan Coal Company (**"**SJCC**"**) mines and delivers coal for consumption in the San Juan Generating Station ("SJGS");

WHEREAS, SJCC has advised Utility that SJCC has encountered and expects to continue encountering areas of high sulfur coal in the mine that may be problematic for SJGS operations;

WHEREAS, the Parties desire for SJCC to undertake a sulfur blending program to mitigate the potential issue of high sulfur coal deliveries to SJGS, as set forth in this Amendment No. 1, and to compensate SJCC for the sulfur blending program.

AGREEMENT

NOW THEREFORE, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

1. Amendments. Articles 1, 5 and 8 of the CSA are amended as follows:

1.1 Section 1.10 is amended by replacing the definition with:

"Processed Coal" shall mean Mineable Coal, and, as applicable, Non-SJCC Coal that has been processed according to Section 7.3 and, as applicable, coal that has been blended in accordance with the Sulfur Blending Program as set forth in Exhibit P.

1.2 Section 1.27 is hereby amended by renumbering it Section 1.29 and adding the following definitions:

(XX) "Sulfur Blending Charge", defined in Section 8.1(I); and

(YY) "Sulfur Blending Program", defined in Section 5.2(E).

1.3 Section 1 is hereby amended by adding the following new Sections 1.27 and 1.28:

Section 1.27 Sulfur Blending Price

The Sulfur Blending Price shall be $0.49 per ton adjusted by the Sulfur Quarterly Price Adjustment.

Section 1.28 Sulfur Quarterly Price Adjustment

The Sulfur Quarterly Price Adjustment shall mean a quarterly adjustment made to the Sulfur Blending Price each calendar quarter during each Contract Year in accordance with the formula and examples set out at Exhibit Q.

1.4 Section 5.2 is hereby amended by adding the following paragraphs as Subsections (E), (F), and (G):

(E) Sulfur Blending Program. SJCC shall undertake, beginning July 1, 2017 and continuing through the end of the Term, a "Sulfur Blending

Program" as set forth in Exhibit P. Payments under this Amendment shall represent the sole form of compensation to SJCC for undertaking the Sulfur Blending Program or any form of high sulfur mitigation required for reliable operation of SJGS, and not subject to reopening, SJCC shall include in its monthly coal billing under Section 8.7(A), the compensation provided for in Section 8.1(I).

(F) High Sulfur Penalty. In the event that SJCC deliveries over any 5-day (such days being the 24-hr period as described in Section 5.2(B)) rolling period exceeds a weighted-average sulfur content of 1.25%, then a process of mathematically culling daily high sulfur samples from the highest to the lowest sulfur content will be followed for the daily samples making up such 5-day rolling average until the 5-day weighted-average sulfur content is less than or equal to 1.25%. The daily tonnages associated with said daily samples so culled shall be subtracted from the Tier 1 Tonnage Allocation amount for that month for purposes of determining the Sulfur Blending Charge. No daily tonnage and sample may be subject to this removal more than once, so that, if the same daily sample was subject to the culling process above in a subsequent 5-day rolling average review, the tonnage associated with it would not be subject to elimination of the Sulfur Blending Charge more than once. An example calculation of the Sulfur Blending Charge is included in Exhibit Q. Weighing, sampling and analysis of coal for the Sulfur Blending Charge shall be as described in Section 5.3.

Until such time that the on-line analyzer newly installed (2017) in the coal delivery system is fully calibrated, SJCC will continue to provide analysis on 3,000 ton increments from the existing mechanical sampling system. The daily sample during this period will be the weighted average of the daily increments. Following full calibration, SJCC will directly provide real time on-line analyzer measurements to SJGS. For avoidance of doubt, the on-line analyzer measurements are for real time reporting purposes only and

the Sulfur Blending Charge tonnage adjustment in this Section 5.2(F) will be based solely on daily ASTM certified sampling and analysis of the associated daily tons as determined from the existing mechanical sampling system.

(G) Sulfur Blending Program Conformance. The matter of whether SJCC is or has been conducting its operations in conformance with the Sulfur Blending Program shall be subject to the dispute resolution provisions of this Agreement.

1.5 Section 8.1 of the CSA, Compensation, is hereby amended by adding the following paragraph as Subsection (I):

(I) Provided that a payment is due under Section 8.1(A), the following will apply: Utility shall pay to SJCC, on a monthly basis, an amount equal to the monthly Tier 1 Tonnage Allocation amount, multiplied by the applicable Sulfur Blending Price ("Sulfur Blending Charge"). The Sulfur Blending Charge shall be paid on all Tier 1 Tonnage Allocation amounts, provided such tons are delivered to the Utility on an annual basis and subject to the penalty provision of Section 5.2(F), beginning with and including the July 2017 Tier 1 Tonnage Allocation amount, such that the first Sulfur Blending Charge amount due will be based on the then cumulative Tier 1 Tonnage Allocation amount from and including the July 2017 Tier 1 Tonnage Allocation amount. No Sulfur Blending Charge will be payable to SJCC for Tier 1 Tonnage Allocation amounts that occurred prior to July 2017.

1.6 The list of Exhibits and Attachments to the CSA is amended by adding the following:

Exhibit P Sulfur Blending Program
Exhibit Q Sulfur Quarterly Price Adjustment

2. Other Terms and Conditions.

2.1 Full Force and Effect. Except as expressly amended by this Amendment No. 1, all other terms of the CSA remain in full force and effect.

2.2 Counterparts. This Amendment No. 1 may be executed in one or more counterparts, including by facsimile or electronic signature, but each such counterpart shall be deemed an original and all such counterparts shall be deemed one and the same instrument.

2.3 Entire Amendment; Successors and Assigns. This Amendment No. 1 contains the entire understanding of the Parties and supersedes all prior agreements and understandings between the Parties relating to the subject matter herein. This Amendment No. 1 shall be binding upon and inure to the benefit of the Parties' respective successors and permitted assigns.

2.4 Condition Precedent: The terms of this Amendment No. 1 shall be effective on the date Westmoreland executes and delivers to PNM the Consent of Guarantor in the form attached to this Amendment No. 1. Notwithstanding the foregoing, Westmoreland will be entitled to payment of the Sulfur Blending Charge retroactively to July 1, 2017.

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IN WITNESS WHEREOF, the Parties have executed this Amendment No. 1 as of the date first written above.

PUBLIC SERVICE COMPANY OF NEW MEXICO

By: /s/ Thomas Fallgren
Name: Thomas Fallgren
Its: VP PNM Generation

WESTMORELAND COAL COMPANY

By: /s/ Joseph E. Micheletti
Name: Joseph E. Micheletti
Its: Chief Operating Officer

Exhibit 10.4

Attachment 1

CONSENT OF GUARANTOR

Westmoreland Coal Company, a Delaware corporation, the guarantor of the obligations of San Juan Coal Company under the Coal Supply Agreement pursuant to the guaranty dated July 1, 2015 (the "Guaranty"), hereby consents to the foregoing Amendment No. 1 to the Coal Supply Agreement and agrees that all references in the Guaranty to the Coal Supply Agreement shall be deemed to be references to the Coal Supply Agreement as amended by Amendment No. 1.

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WESTMORELAND COAL COMPANY

(corporate seal)

By: /s/ Joseph E. Micheletti
Name: Joseph E. Micheletti
Title: Chief Operating Officer
Date: 11/13/2017

ATTEST:

By: /s/ Lauren B. Elan-Aubrey 11/13/2017
Secretary Date

EXHIBIT P – SULFUR BLENDING PROGRAM

SJCC shall make all commercially reasonable efforts to conduct the Sulfur Blending Program in order to achieve the following objectives:

1. SJCC shall endeavor to provide to the Utility, as-delivered coal meeting the following "as-received" sulfur parameters:

    a. "As-received" sulfur content not to exceed 1.1% by weight on a thirty-calendar-day rolling, weighted average basis. The thirty-calendar-day rolling average will be calculated based on the average sulfur content for each day, being a 24-hour period as defined in this Agreement, for days when coal is delivered to the plant.

    b. "As-received" sulfur content not to exceed 1.25% by weight for any 24-hour period of sampling. Such sampling period as defined in Section 5.2 of this Agreement.

SJCC shall take the following actions as part of the Sulfur Blending Program:

1. Mine Plan Modifications

    a. The gate roads for Panel 405 will be extended so that the set-up room of Panel 405 will be no further west than the set-up rooms for Panels 401 – 404.

    b. The longwall recovery chutes for Panel 405 will be located and driven prior to the completion of Panel 405.

    c. A mine sequence map is attached for reference.

2. Coal Handling Measures

    a. A longwall uni-di cut, providing limited on face separation of coal and/or rock layers, will be utilized as required when mining high in-situ sulfur content zones.

    b. ROM coal that cannot be delivered directly or blended to achieve the required "as-received" sulfur content will be rejected and hauled to the ash disposal.

    c. ROM coal production that cannot directly meet the 1.1% "as-received" sulfur limitation will be diverted to one of four stockpile locations in the North Field and Juniper Stockpiles for future blending and final delivery to the plant. (See attached flowchart.)

    d. The underground stackout and reject chute will be managed to minimize the risk of contaminating deliverable coal.

Exhibit 10.4

    e. SJCC will update and utilize its Coal Quality Model in planning based on inputs from:

        i. Surface drill holes;
        ii. On-going channel sampling program; and
        iii. Reconciliation of coal quality as determined by lab and on-line analyzer results versus expectations from the Coal Quality Model.

3. Communication and Reporting

    a. A status update and review of the Sulfur Blending Program will be an agenda item for each Mining Oversight Committee meeting and/or other regularly scheduled joint mine and plant meeting.

    b. The on-line analyzer summary output report will be sent directly to the plant or other SJGS representative as directed by SJGS.

    c. SJCC will continue to put emphasis on maintaining minimal variation to as-delivered sulfur content, similar to emphasis of maintaining minimal

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variation to BTU content.

d. SJCC will include a schedule in the Section 8.7(A) invoice that details the following:

i. The calculation of the Sulfur Blending Charge.
ii. Details of the Sulfur Quarterly Price Adjustment.
iii. The Tier 1 Tonnage Allocation used to compute the Sulfur Blending Charge.
iv. All applicable taxes and royalties associated with the Sulfur Blending Charge.

Exhibit 10.4

Planned Mining Sequence

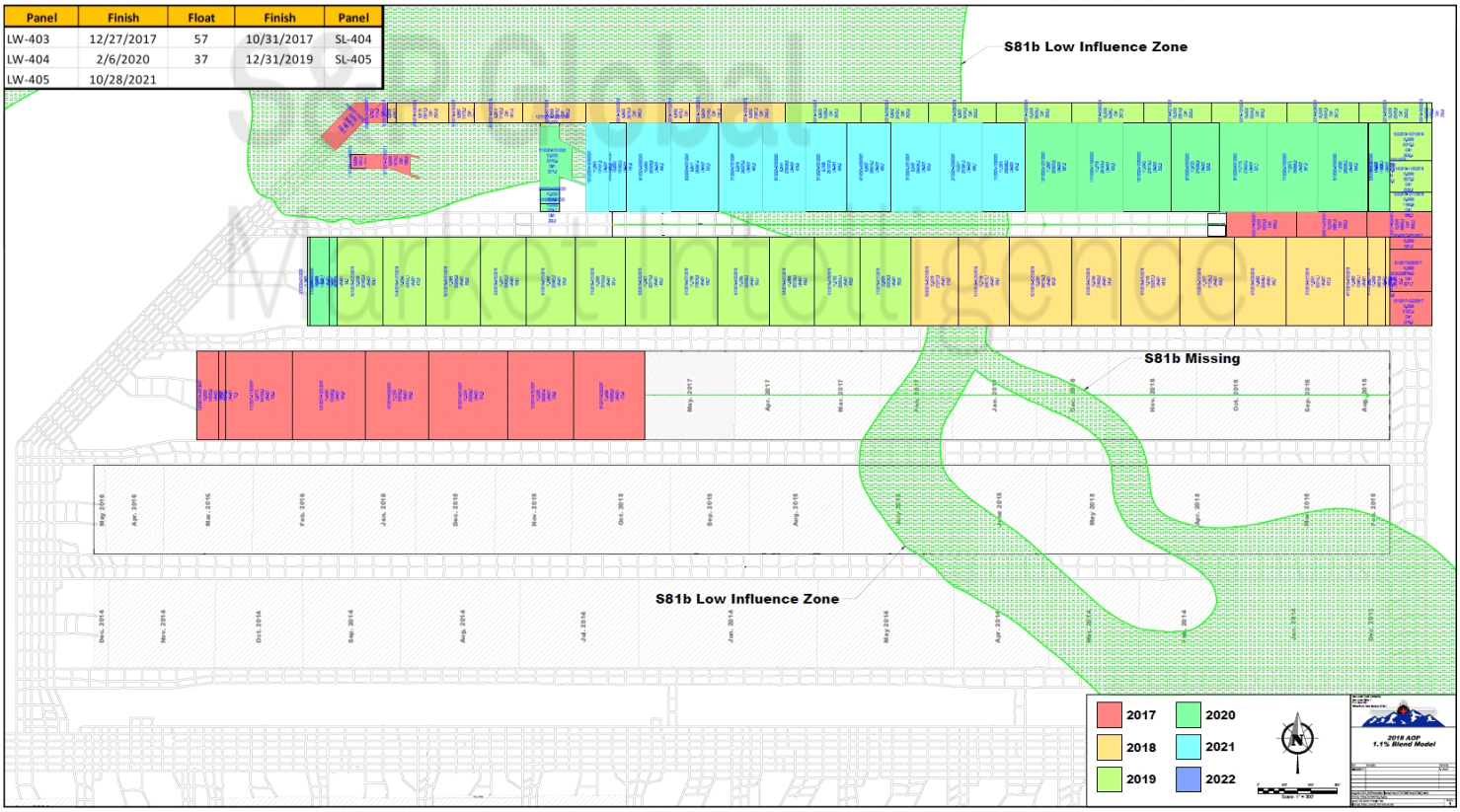

Exhibit 10.4

Coal Flow Sheet:

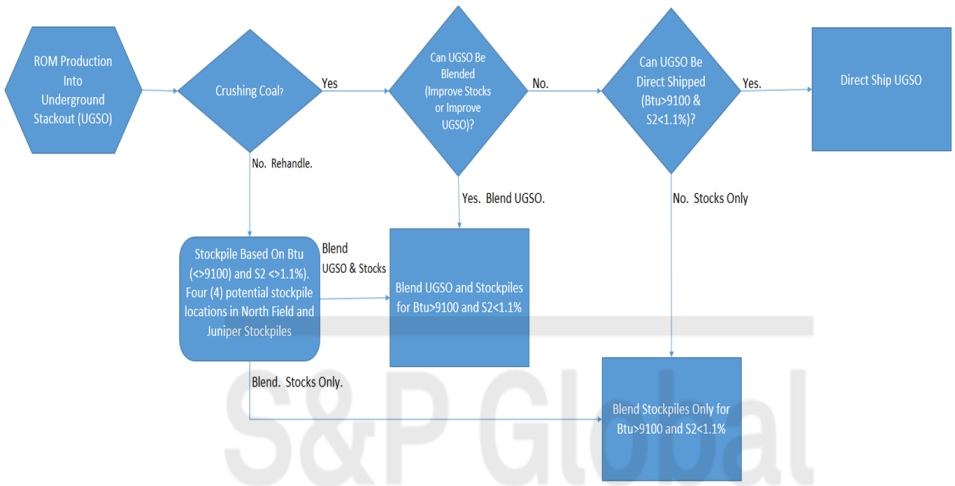

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Exhibit 10.4

EXHIBIT Q

Sulfur Quarterly Price Adjustment Example
Base Value Index Sample Calculation for Q_3 2017

Index Description	Series ID	Value	Weight	Basis
Labor and Benefits	***CEU1021210008***	31.0000	26.00%	Q_3 2017 CSA Value
Medical	***CUUR0000SAM***	474.3600	17.00%	Q_3 2017 CSA Value
Diesel Fuel	***PCU 324110324110***	209.7000	5.00%	Q_3 2017 CSA Value
Electricity	***Actual Price, ¢/KWH***	0.0938	6.00%	Q_3 2017 CSA Value
Fixed Index	***0.625% per Quarter***	1.0643	46.00%	Q_3 2017 CSA Value
Base Index Value		1.000	100.00%	

Sample Index Update for Q_4 2017

Index Description	Series ID	Value	Weight	Basis
Labor and Benefits	***CEU1021210008***	32.0000	26.00%	Q_4 2017 Value
Medical	***CUUR0000SAM***	480.0000	17.00%	Q_4 2017 Value
Diesel Fuel	***PCU 324110324110***	212.0000	5.00%	Q_4 2017 Value
Electricity	***Actual Price, ¢/KWH***	0.0950	6.00%	Q_4 2017 Value
Fixed Index	***0.625% per Quarter***	1.0709	46.00%	Q_4 2017 Value
Base Index Value		1.015	100.00%	

Base Index = ((31/31)×.26)+((473.512/473.512)×.17+((210.8/210.8)×.05)+((.0938/.0938)×.06)+((1.0643/1.0643)×.46)=1.000

Quarterly Composite Index = ((32/31)×.26)+((480.000/474.360)×.17+((212.0/209.700)×.05)+((.095/.0938)×.06)+((1.0709/1.0643)×.46)=1.015

Index Multiplier = Quarterly Composite Index/Base Index = 1.015/1.000 = 1.015

Sulfur Blending Price = Base Price * Index Multiplier = $0.49×1.015 = $0.50/ton

Rounding conventions follow those used in the coal price escalator and unit coal pricing calculations:
Index and multiplier calculations round to three decimal places; Unit pricing calculations round to the nearest cent.
Index and Multiplier values above are hypothetical for purposes of illustration
The Base indice values above per the July 2017 CSA invoicing cycle.

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Section 6: EX-10.5 (EXHIBIT 10.5)

Exhibit 10.5

Acknowledgement Form

[Date]

[Name of Director]

Dear: _____

Pursuant to the PNM Resources, Inc. 2014 Performance Equity Plan (the 'Plan'), you have been granted a Restricted Stock Rights Award for ____ shares of stock of PNM Resources, Inc. as outlined below.

Employee ID: _____

Granted To: _____

Grant ID: ___

Grant Date: _____

Granted: _____

Grant Price: $0.000000

Vesting Schedule: 1 year cliff

Vesting Schedule - Restricted Stock Rights Award	
Vest Date [1]	Vest Quantity
_____	_____

By my acceptance below, I hereby (1) acknowledge receipt of this Grant on the date shown above, which has been issued to me under the attached Terms and Conditions and the Plan, (2) acknowledge receipt of the copy of the Plan and the Terms and Conditions of this Grant, and (3) agree to conform to all of the attached Terms and Conditions of the Grant and the Plan.

_____

[1] Vested Restricted Stock Rights will be delivered in accordance with any elections made under the Director Deferred Rights Program, provided that if vesting or any applicable deferred delivery dates occur during a blackout period, the vested shares will be delivered at a later date after such blackout period ends.

Terms and Conditions of Restricted Stock Rights Award to Non-Employee Directors

Pursuant to the PNM Resources, Inc. 2014 Performance Equity Plan, you have been granted a Restricted Stock Rights Award for the number of shares specified on the Acknowledgment Form attached. The Acknowledgment Form and these Terms and Conditions are collectively referred to as the "Award Document."

The Restricted Stock Rights Award is subject to all of the provisions set forth in the PNM Resources, Inc. 2014 Performance Equity Plan (the "Plan") and this Award Document. The Restricted Stock Rights Award is also subject to the provisions set forth in the PNM Resources, Inc. Director Deferred Restricted Stock Rights Program ("Deferral Program") if you chose to defer your Restricted Stock Rights Award.

Capitalized terms used in the Award Document that are not otherwise defined herein shall have the meanings given to such terms in the Plan or the Deferral Program.

1. Vesting.

(a) The Restricted Stock Rights Award shall vest in accordance with the vesting schedule on the Acknowledgment Form.

(b) If you have a Termination of Service as a Nonemployee Director, any nonvested Restricted Stock Rights Award will vest pursuant to Section 9.4 of the Plan.

2. Form and Timing of Delivery of Stock.

(a) If the Restricted Stock Rights vest as described on the Acknowledgment Form, you will receive the Stock payable with respect to such vested Restricted Stock Rights Award within ninety (90) days following the dates on which the Restricted Stock Rights vest.

(b) If any Restricted Stock Rights vest as described in Section 1(b), you will receive the Stock payable with respect to such Restricted Stock Rights within ninety (90) days following your Termination of Service.

(c) Notwithstanding the foregoing Sections 2(a) and 2(b), if you elected to participate in the Deferral Program, you will be paid in accordance with your elections and the terms of the Deferral Program.

(d) The delivery of the Restricted Stock Rights may be delayed to the extent necessary to comply with Federal securities laws.

3. Divided Equivalents. You will not be entitled to receive a dividend equivalent for any of the Restricted Stock Rights granted hereunder. You also will not be entitled to receive dividend equivalents, if any, on any Restricted Stock Rights that you deferred pursuant to the Deferral Program.

4. **Voting Rights**. You will have no voting rights with respect to nonvested Restricted Stock Rights. You also will have no voting rights with respect to any Restricted Stock Rights

Exhibit 10.5

that you deferred pursuant to the Deferral Program.

5. Clawback. All or any portion of this Restricted Stock Rights Award is subject to recapture or "clawback" to the extent necessary to comply with Company policy or applicable law. By accepting this Award, you agree to be bound by, and comply with, the terms of any such recapture or clawback provisions and with any Company request or demand for a recapture or clawback.

6. Waiver and Modification. The provisions of this Award Document may not be waived or modified unless such waiver or modification is in writing signed by the Company.

MANY OF THE PROVISIONS OF THIS AWARD DOCUMENT ARE SUMMARIES OF SIMILAR OR PERTINENT PROVISIONS OF THE

PLAN OR THE DEFERRAL PROGRAM. TO THE EXTENT THIS AWARD DOCUMENT IS SILENT ON AN ISSUE OR THERE IS A CONFLICT BETWEEN THE PLAN AND THIS AWARD DOCUMENT OR THE DEFERRAL PROGRAM AND THIS AWARD DOCUMENT, THE PROVISIONS OF THE PLAN OR THE DEFERRAL PROGRAM SHALL CONTROL.

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Section 7: EX-10.6 (EXHIBIT 10.6)

Exhibit 10.6

THIRD AMENDMENT
TO THE
PNM RESOURCES, INC.
NON-UNION SEVERANCE PAY PLAN

Effective January 1, 2002, Public Service Company of New Mexico ("PNM") adopted the Public Service Company of New Mexico Benefits My Way Plan (the "BMW Plan"). Effective November 27, 2002, sponsorship of the BMW Plan was transferred from PNM to PNM Resources, Inc. (the "Company") and the BMW Plan was renamed the "PNM Resources, Inc. Benefits My Way Plan." The BMW Plan consisted of a number of component programs including Program 12, Non-Union Severance Pay Program (the "Non-Union Severance Program"). Effective as of January 1, 2004, the Company amended and restated the BMW Plan to divide it into a number of separate plans that replaced several of the component programs in effect on December 31, 2003. As part of the amendment and restatement, the PNM Resources, Inc. Non-Union Severance Pay Plan (the "Plan") was created as a successor plan to the Non-Union Severance Program, effective as of January 1, 2004. The Plan was most recently amended and restated effective August 1, 2007. By this instrument, the Company now desires to amend the Plan as set forth below.

1. Except as otherwise provided, this Third Amendment shall be effective as of January 3, 2015.

2. Section 2.1(o) (Definitions "Management Group") is hereby amended and restated to read as follows:

(o) "Management Group" means any Participant who is in salary grade G04 through G01 at the time of Impaction.

3. This Third Amendment amends only the provisions of the Plan as noted above, and those provisions not expressly amended shall be considered in full force and effect.

Exhibit 10.6

Notwithstanding the foregoing, this Third Amendment shall supersede the provisions of the Plan to the extent those provisions are inconsistent with the provisions and intent of this Third Amendment.

IN WITNESS WHEREOF, the Company has caused this Third Amendment to be executed as of this 11th day of November, 2015.

PNM RESOURCES, INC.

By: /s/ Patrick V. Apodaca

Its: Sr VP, General Counsel and Corporate Secretary

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Section 8: EX-12.1 (EXHIBIT 12.1)

Exhibit 12.1

PNM RESOURCES, INC. AND SUBSIDIARIES
Ratio of Earnings to Fixed Charges
(In thousands, except ratio)

	Year Ended December 31,				
	2017	2016	2015	2014	2013
Fixed charges, as defined by the Securities and Exchange Commission:					
Interest expensed and capitalized	$ 130,024	$ 129,592	$ 117,932	$ 117,337	$ 118,880
Amortization of debt premium, discount, and expenses	4,106	3,779	3,575	4,194	3,716
Estimated interest factor of lease rental charges	2,567	2,747	3,298	4,686	5,847
Preferred dividend requirements of subsidiary	1,249	781	784	809	800
Total Fixed Charges	$ 137,946	$ 136,899	$ 125,589	$ 127,026	$ 129,243
Earnings, as defined by the Securities and Exchange Commission:					
Earnings before income taxes and non-controlling interest	$ 225,759	$ 195,174	$ 46,153	$ 200,647	$ 175,069
Fixed charges as above	137,946	136,899	125,589	127,026	129,243
Interest capitalized	(8,806)	(7,964)	(9,753)	(6,256)	(5,209)
Non-controlling interest in earnings of Valencia	(15,017)	(14,519)	(14,910)	(14,127)	(14,521)
Preferred dividend requirements of subsidiary	(1,249)	(781)	(784)	(809)	(800)
Earnings Available for Fixed Charges	$ 338,633	$ 308,809	$ 146,295	$ 306,481	$ 283,782
Ratio of Earnings to Fixed Charges	2.45 [1]	2.26 [2]	1.16 [3]	2.41 [4]	2.20 [5]

[1] Earnings before income taxes and non-controlling interest for the year ended December 31, 2017 includes a pre-tax loss of $27.0 million due to the write-off of regulatory disallowances and restructuring costs at PNM. If that loss was excluded, the Ratio of Earnings to Fixed Charges would have been 2.65 for 2017.

[2] Earnings before income taxes and non-controlling interest for the year ended December 31, 2016 includes a pre-tax loss of $15.0 million due to the write-off of regulatory disallowances and restructuring costs at PNM. If that loss was excluded, the Ratio of Earnings to Fixed Charges would have been 2.37 for 2016.

[3] Earnings before income taxes and non-controlling interest for the year ended December 31, 2015 includes a pre-tax loss of $167.5 million due to the write-off of regulatory disallowances and restructuring costs at PNM. If that loss was excluded, the Ratio of Earnings to Fixed Charges would have been 2.50 for 2015.

[4] Earnings before income taxes and non-controlling interest for the year ended December 31, 2014 includes a pre-tax loss of $1.1 million due to the write-off of regulatory disallowances at PNM. If that loss was excluded, the Ratio of Earnings to Fixed Charges would have been 2.42 for 2014.

[5] Earnings before income taxes and non-controlling interest for the year ended December 31, 2013 includes a pre-tax loss of $12.2 million due to the write-off of regulatory disallowances at PNM. If that loss was excluded, the Ratio of Earnings to Fixed Charges would have been 2.29 for 2013.

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Section 9: EX-12.2 (EXHIBIT 12.2)

Exhibit 12.2

PUBLIC SERVICE COMPANY OF NEW MEXICO
Ratio of Earnings to Fixed Charges
(In thousands, except ratio)

	Year Ended December 31,				
	2017	2016	2015	2014	2013
Fixed charges, as defined by the Securities and Exchange Commission:					
Interest expensed and capitalized	$ 86,121	$ 89,502	$ 84,695	$ 79,834	$ 79,769
Amortization of debt premium, discount, and expenses	2,677	2,312	1,978	1,944	1,879
Estimated interest factor of lease rental charges	1,182	1,217	1,532	2,541	3,732
Total Fixed Charges	$ 89,980	$ 93,031	$ 88,205	$ 84,319	$ 85,380
Earnings, as defined by the Securities and Exchange Commission:					
Earnings (loss) before income taxes and non-controlling interest	$ 168,968	$ 132,860	$ (13,082)	$ 154,086	$ 151,480
Fixed charges as above	89,980	93,031	88,205	84,319	85,380
Non-controlling interest in earnings of Valencia	(15,017)	(14,519)	(14,910)	(14,127)	(14,521)
Interest capitalized	(6,917)	(6,094)	(8,530)	(5,211)	(4,420)
Earnings Available for Fixed Charges	$ 237,014	$ 205,278	$ 51,683	$ 219,067	$ 217,919
Ratio of Earnings to Fixed Charges	2.63 [1]	2.21 [2]	0.59 [3]	2.60 [4]	2.55 [5]

[1] Earnings (loss) before income taxes and non-controlling interest for the year ended December 31, 2017 includes a pre-tax loss of $27.0 million due to the write-off of regulatory disallowances and restructuring costs. If that loss was excluded, the Ratio of Earnings to Fixed Charges would have been 2.93 for 2017.

[2] Earnings (loss) before income taxes and non-controlling interest for the year ended December 31, 2016 includes a pre-tax loss of $15.0 million due to the write-off of regulatory disallowances and restructuring costs. If that loss was excluded, the Ratio of Earnings to Fixed Charges would have been 2.37 for 2016.

[3] The shortfall in the earnings available for fixed charges to achieve a ratio of earnings to fixed charges of 1.00 amounted to $36.5 million for the year ended December 31, 2015. Earnings (loss) before income taxes and non-controlling interest for the year ended December 31, 2015 includes a pre-tax loss of $167.5 million due to the write-off of regulatory disallowances and restructuring costs. If that loss was excluded, the Ratio of Earnings to Fixed Charges would have been 2.48 for 2015.

[4] Earnings (loss) before income taxes and non-controlling interest for the year ended December 31, 2014 includes a pre-tax loss of $1.1 million due to the write-off of regulatory disallowances. If that loss was excluded, the Ratio of Earnings to Fixed Charges would have been 2.61 for 2014.

[5] Earnings (loss) before income taxes and non-controlling interest for the year ended December 31, 2013 includes a pre-tax loss of $12.2 million due to the write-off of regulatory disallowances. If that loss was excluded, the Ratio of Earnings to Fixed Charges would have been 2.70 for 2013.

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Section 10: EX-12.3 (EXHIBIT 12.3)

Exhibit 12.3

TEXAS-NEW MEXICO POWER COMPANY
Ratio of Earnings to Fixed Charges
(In thousands, except ratio)

	Year Ended December 31,				
	2017	2016	2015	2014	2013
Fixed charges, as defined by the Securities and Exchange Commission:					
Interest expensed and capitalized	$ 28,739	$ 27,698	$ 25,875	$ 24,941	$ 24,481
Amortization of debt premium, discount, and expenses	1,048	1,039	1,100	1,195	1,159
Estimated interest factor of lease rental charges	1,190	1,249	1,229	1,311	1,241
Total Fixed Charges	$ 30,977	$ 29,986	$ 28,204	$ 27,447	$ 26,881
Earnings, as defined by the Securities and Exchange Commission:					
Earnings from continuing operations before income taxes	$ 67,071	$ 65,508	$ 66,088	$ 60,330	$ 46,711
Fixed charges as above	30,977	29,986	28,204	27,447	26,881
Interest capitalized	(1,189)	(877)	(593)	(609)	(361)
Earnings Available for Fixed Charges	$ 96,859	$ 94,617	$ 93,699	$ 87,168	$ 73,231
Ratio of Earnings to Fixed Charges	3.13	3.16	3.32	3.18	2.72

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Section 11: EX-21 (EXHIBIT 21)

EXHIBIT 21

Subsidiaries of PNM Resources, Inc.

As of December 31, 2017, PNM Resources, Inc. directly or indirectly owns all of the voting securities of the following subsidiaries:

Public Service Company of New Mexico, a New Mexico corporation that does business under the names “Public Service Company of New Mexico” and “PNM”.

Texas-New Mexico Power Company, a Texas corporation that does business under the name “Texas-New Mexico Power Company” and “TNMP”.

TNP Enterprises, Inc., a Texas corporation that does business under its corporate name.

The remaining subsidiaries of PNM Resources, Inc. considered in the aggregate as a single subsidiary, do not constitute a "significant subsidiary" (as defined in Rule 1-02(w) of Regulation S-X) as of the end of the year covered by this report.

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Section 12: EX-23.1 (EXHIBIT 23.1)

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors

PNM Resources, Inc.:

We consent to the incorporation by reference in the registration statement No. 333-206087 on Form S-3 and registration statement Nos. 333-76288, 333-139108, 333-129454, 333-121371, 333-125010, 333-141282, 333-156243, 333-159361, 333-159362, 333-168797, and 333-195974 on Form S-8 of PNM Resources, Inc. of our report dated March 1, 2018, with respect to the consolidated balance sheets of PNM Resources, Inc. and subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of earnings, consolidated statements of comprehensive income, consolidated statements of changes in equity, and consolidated statements of cash flows for each of the years in the three-year period ended December 31, 2017, the related notes and financial statement Schedule I – Condensed Financial Information of Parent Company and Schedule II – Valuation and Qualifying Accounts (collectively, the consolidated financial statements), and the effectiveness of internal control over financial reporting as of December 31, 2017, which report appears in the December 31, 2017 annual report on Form 10-K of PNM Resources, Inc.

/s/ KPMG LLP

Albuquerque, New Mexico
March 1, 2018

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Section 13: EX-23.2 (EXHIBIT 23.2)

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

The Board of Directors
Public Service Company of New Mexico:

We consent to the incorporation by reference in the registration statement No. 333-218059 on Form S-3 of Public Service Company of New Mexico of our report dated March 1, 2018, with respect to the consolidated balance sheets of Public Service Company of New Mexico and subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of earnings (loss), consolidated statements of comprehensive income (loss), consolidated statements of changes in equity, and consolidated statements of cash flows for each of the years in the three-year period ended December 31, 2017, the related notes and Schedule II – Valuation and Qualifying Accounts (collectively, the consolidated financial statements), which report appears in the December 31, 2017 annual report on Form 10-K of Public Service Company of New Mexico.

/s/ KPMG LLP

Albuquerque, New Mexico
March 1, 2018

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Section 14: EX-31.1 (EXHIBIT 31.1)

EXHIBIT 31.1

CERTIFICATION

I, Patricia K. Collawn, certify that:

1. I have reviewed this Annual Report on Form 10-K of PNM Resources, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (each registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2018

By: /s/ Patricia K. Collawn

Patricia K. Collawn
President and Chief Executive Officer
PNM Resources, Inc.

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Section 15: EX-31.2 (EXHIBIT 31.2)

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EXHIBIT 31.2

CERTIFICATION

I, Charles N. Eldred, certify that:

1. I have reviewed this Annual Report on Form 10-K of PNM Resources, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (each registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2018

By: /s/ Charles N. Eldred

Charles N. Eldred
Executive Vice President and
Chief Financial Officer

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Section 16: EX-31.3 (EXHIBIT 31.3)

EXHIBIT 31.3

CERTIFICATION

I, Patricia K. Collawn, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Company of New Mexico;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (each registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2018

By: /s/ Patricia K. Collawn

Patricia K. Collawn
President and Chief Executive Officer
Public Service Company of New Mexico

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Section 17: EX-31.4 (EXHIBIT 31.4)

EXHIBIT 31.4

CERTIFICATION

I, Charles N. Eldred, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Company of New Mexico;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (each registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2018

By: /s/ Charles N. Eldred

Charles N. Eldred
Executive Vice President and
Chief Financial Officer

Public Service Company of New Mexico

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Section 18: EX-31.5 (EXHIBIT 31.5)

EXHIBIT 31.5

CERTIFICATION

I, Patricia K. Collawn, certify that:

1. I have reviewed this Annual Report on Form 10-K of Texas-New Mexico Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary in order to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2018

By: /s/ Patricia K. Collawn
Patricia K. Collawn
Chief Executive Officer
Texas-New Mexico Power Company

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Section 19: EX-31.6 (EXHIBIT 31.6)

EXHIBIT 31.6

CERTIFICATION

I, Charles N. Eldred, certify that:

1. I have reviewed this Annual Report on Form 10-K of Texas-New Mexico Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary in order to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2018

By: /s/ Charles N. Eldred
Charles N. Eldred
Executive Vice President and
Chief Financial Officer
Texas-New Mexico Power Company

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Section 20: EX-32.1 (EXHIBIT 32.1)

EXHIBIT 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. § 1350, AS ADOPTED PURSUANT TO § 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K for the period ended December 31, 2017, for PNM Resources, Inc. ("Company"), as filed with the Securities and Exchange Commission on March 1, 2018 ("Report"), each of the undersigned officers of the Company certifies, pursuant to 18 U.S.C. §1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of § 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 1, 2018

By: /s/ Patricia K. Collawn
Patricia K. Collawn
President and Chief Executive Officer
PNM Resources, Inc.

By: /s/ Charles N. Eldred
Charles N. Eldred
Executive Vice President and
Chief Financial Officer
PNM Resources, Inc.

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Section 21: EX-32.2 (EXHIBIT 32.2)

S&P Global Market Intelligence

EXHIBIT 32.2

CERTIFICATION PURSUANT TO 18 U.S.C. § 1350, AS ADOPTED PURSUANT TO § 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K for the period ended December 31, 2017, for Public Service Company of New Mexico ("Company"), as filed with the Securities and Exchange Commission on March 1, 2018 ("Report"), each of the undersigned officers of the Company certifies, pursuant to 18 U.S.C. §1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of § 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 1, 2018

By: /s/ Patricia K. Collawn
Patricia K. Collawn
President and Chief Executive Officer
Public Service Company of New Mexico

By: /s/ Charles N. Eldred
Charles N. Eldred
Executive Vice President and
Chief Financial Officer
Public Service Company of New Mexico

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Section 22: EX-32.3 (EXHIBIT 32.3)

EXHIBIT 32.3

CERTIFICATION PURSUANT TO 18 U.S.C. § 1350, AS ADOPTED PURSUANT TO § 906 OF THE

SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K for the period ended December 31, 2017, for Texas-New Mexico Power Company ("Company"), as filed with the Securities and Exchange Commission on March 1, 2018 ("Report"), each of the undersigned officers of the Company certifies, pursuant to 18 U.S.C. §1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of § 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 1, 2018

By: /s/ Patricia K. Collawn
Patricia K. Collawn
Chief Executive Officer
Texas-New Mexico Power Company

By: /s/ Charles N. Eldred
Charles N. Eldred
Executive Vice President and
Chief Financial Officer
Texas-New Mexico Power Company

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S&P Global
Market Intelligence

Working Paper Series
Congressional Budget Office
Washington, D.C.

Did Treasury Debt Markets Anticipate the Persistent Decline in Long-Term Interest Rates?

Edward N. Gamber
Congressional Budget Office
ed.gamber@cbo.gov

Working Paper 2017-07

September 2017

To enhance the transparency of the work of the Congressional Budget Office and to encourage external review of that work, CBO's working paper series includes both papers that provide technical descriptions of official CBO analyses and papers that represent original, independent research by CBO analysts. The information in this paper is preliminary and is being circulated to stimulate discussion and critical comment as developmental work for analysis for the Congress. Papers in this series are available at http://go.usa.gov/ULE.

For helpful comments and suggestions, the author thanks Bob Arnold, Wendy Edelberg, Mike Falkenheim, Kim Kowalewski, Damien Moore, Jeff Perry, and Jeff Werling (all of CBO), as well as Jan Hatzius and Brian Sack. The author thanks Christine Bogusz for editing.

Abstract

Private-sector forecasters consistently missed the decline in long-term nominal interest rates over the past three decades, estimating rates that were higher (and, in some cases, much higher) than what actually occurred. This analysis examines whether bond-market participants anticipated with greater accuracy the decline in long-term rates. To explore that issue, the Congressional Budget Office compared the accuracy and bias in forecasts of long-term interest rates from the *Blue Chip* consensus with forecasts based on information derived from the Treasury yield curve as well as several benchmark forecasts and combinations of forecasts. The results indicate that Treasury debt markets did not do a better job than the *Blue Chip* consensus in forecasting the decline in long-term interest rates over the past three decades. Forecasts based on a random walk model of interest rates were more accurate and less biased than those of the *Blue Chip* consensus, especially for the most recent subsample period (1998–2012).

Keywords: long-term interest rates, forecast errors, Treasury yield curve

JEL Classification: E47

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Introduction

Long-term interest rates in the United States have declined steadily over the past 30 years.[1] Over that same period, private-sector forecasters—as represented by the *Blue Chip* consensus—have generally estimated higher interest rates than what actually occurred.[2] In this analysis, the Congressional Budget Office investigated whether information available from the yield curve at the time the *Blue Chip*'s forecasts were made could have been used to better anticipate the decline in long-term interest rates.[3]

The results of this analysis indicate that compared with the *Blue Chip* consensus, Treasury debt markets did not do a better job forecasting the decline in long-term interest rates over the past three decades. The *Blue Chip* consensus forecast of long-term interest rates was as accurate, or more accurate, than forecasts based on the information contained in the Treasury yield curve. In addition, forecasts based on the Treasury yield curve were not consistently less biased than those of the *Blue Chip* consensus. Combining the two sets of forecasts—those based on the Treasury yield curve and those from the *Blue Chip* consensus—also did not produce significantly more accurate or less biased forecasts.

CBO found that forecasts based on simple benchmark models were more accurate and less biased than those from the *Blue Chip* consensus. That finding was particularly true for forecasts based on the random walk model, especially over the 1998–2012 period. The random walk model naively assumed that interest rates would remain constant, whereas the *Blue Chip* consensus and yield curve–based forecasts assumed that interest rates would move back up to historical levels. By construction, therefore, the random walk–based model was more accurate in an environment of persistently falling interest rates.

---

[1]Real (inflation-adjusted) and nominal long-term interest rates have declined worldwide since the early 1980s. See Rachel and Smith (2015).

[2]The *Blue Chip* consensus is the average of roughly 50 forecasts by private-sector economists (see *Blue Chip Economic Indicators*). It reflects a broader blend of sources and methods than can be expected from a single forecaster. Such combinations of forecasts often provide better estimates than those made by a single forecaster or using a single forecast method. See, for example, Timmerman (2006), Bauer and others (2003), Townsend (1996), and Clemen (1989).

[3]Other researchers have investigated whether the yield curve contains information useful for forecasting interest rates. See, for example, Fama and Bliss (1987), Cochrane and Piazzesi (2005), and Diebold and Rudebusch (2013). Unlike this analysis, those studies have tended to focus on short time horizons (typically one year or less).

The *Blue Chip* Consensus Forecast of Long-Term Interest Rates

To evaluate forecasts of long-term interest rates by the *Blue Chip* consensus, CBO used two measures of forecast quality: statistical bias and accuracy. Statistical bias measures the degree to which the average forecast error differs from zero. Accuracy measures the dispersion of the forecasts around the actual values; it is shown by the root mean square error (RMSE). CBO evaluated the bias and accuracy of the one- through five-year-ahead forecasts of long-term interest rates produced by the *Blue Chip* consensus over the sample period from March 1984 to March 2012, as well as over two subsample periods: March 1984 to October 1997 and March 1998 to March 2012.[4]

The RMSEs of the long-term interest rate forecasts produced by the *Blue Chip* consensus between 1984 and 2012 varied from a low of 0.69 percentage points for the one-year-ahead forecasts to a high of 1.80 percentage points for the five-year-ahead forecasts (see **Table 1**). Over that same period, the forecasts also exhibited significant positive bias (meaning they were too high) for horizons from one through five years (see **Table 2** and **Figure 1**).

Blue Chip's forecasts of long-term interest rates have become more biased and less accurate over time: The RMSEs are substantially larger (in some cases more than twice as large) in the 1998–2012 period as in the 1984–1997 period. Bias also increased from the first half of the sample (1984 through 1997) to the second half (1998 to 2012), which is consistent with the visual impression from Figure 1.

[4]The long-term forecasts by the *Blue Chip* consensus are published in March and October. Long-term interest rates were measured as the AAA corporate bond rate before 1996 and the 10-year Treasury note rate from 1996 onward. The total number of forecasts analyzed in this study is 57. The last forecast in the sample extends through 2016. The two subsamples were chosen by dividing the full sample roughly in half.

Table 1. RMSE of the *Blue Chip* Consensus's 10-Year Treasury Note Forecasts

Horizon (Years)	1984–2012, N=57	1984–1997, N=28	1998–2012, N=29
1	0.69	0.81	0.56
2	1.22	1.16	1.27
3	1.46	1.11	1.74
4	1.59	0.96	2.02
5	1.8	1.11	2.28

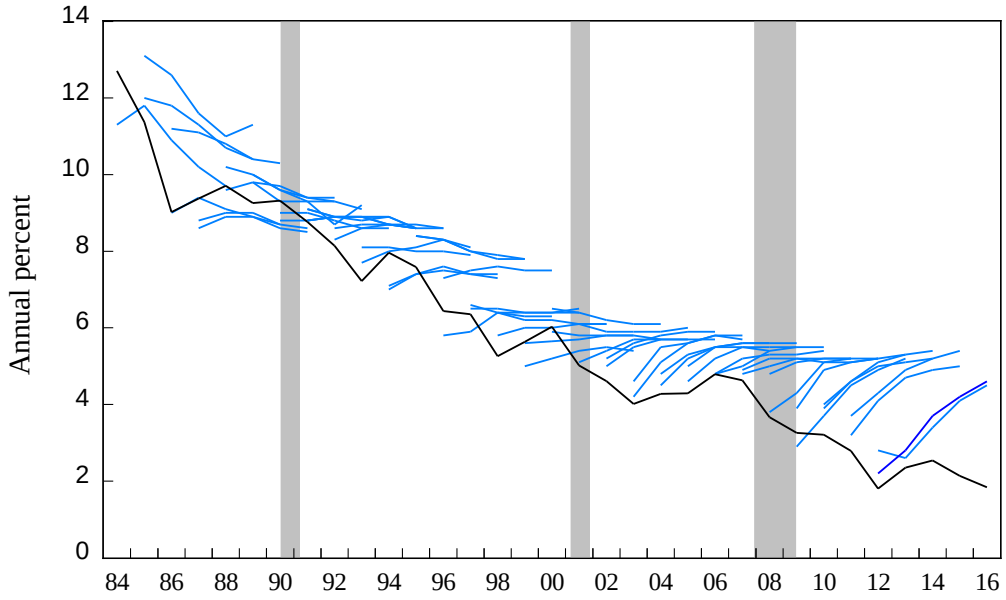
Each cell in the table shows the root mean square error (RMSE) for the forecast horizon listed in the far-left column over the sample shown in the column heading. The RMSE calculations are based on the AAA corporate bond rate from 1984 through 1996 and the 10-year Treasury note rate from 1997 through 2012.

Table 2. Statistical Bias in the *Blue Chip* Consensus's 10-Year Treasury Note Forecasts

Horizon (Years)	1984–2012, N=57	1984–1997, N=28	1998–2012, N=29
1	0.29**	0.23	0.36**
	(0.08)	(0.13)	(0.09)
2	0.85**	0.65**	1.04**
	(0.17)	(0.25)	(0.19)
3	1.18**	0.78**	1.57**
	(0.20)	(0.22)	(0.23)
4	1.33**	0.74**	1.91**
	(0.21)	(0.16)	(0.23)
5	1.55**	0.91**	2.16**
	(0.22)	(0.15)	(0.25)

Each cell in the table shows the average forecast error for the forecast horizon listed in the far-left column calculated over the sample shown in the column heading. Beneath the average error is the Newey-West standard error. Positive numbers indicate that the forecasted value was above the actual value, on average. The asterisks indicate statistical significance corresponding to the null hypothesis that the bias is zero: ** denotes significance at the 0.01 level.

Figure 1. Long-Term Interest Rate Forecasts From the *Blue Chip* Consensus, 1984 to 2012



The figure shows the actual interest rate (the black line) and 57 *Blue Chip* consensus forecasts, published in March and October of each year. Before 1996, the interest rate is the AAA corporate bond rate. After 1996, it is the 10-year Treasury note rate.

The Theoretical Basis for Using the Yield Curve to Forecast Interest Rates

The theoretical basis for using the yield curve to forecast interest rates follows from the expectations hypothesis (EH) of the term structure, which posits that current long-term interest rates equal the average of expected short-term rates (see Cochrane and Piazzesi, 2008). For example, if investors are indifferent between purchasing a 2-period bond with a log yield of $y_t^{(2)}$ and purchasing a sequence of two 1-period bonds with log yields of $y_t^{(1)}$and $y_{t+1}^{(1)}$, then the EH, which assumes an absence of arbitrage opportunities in the bond market, implies:[5]

$$y_t^{(2)} = \frac{y_t^{(1)} + {}_t y_{t+1}^{(1)}}{2} \qquad (1)$$

[5]The finance literature typically expresses the expectations hypothesis in terms of log yields. The log yield on an n-period discount bond can be represented as $y_t^n \equiv -\frac{1}{n} p_t^n$ where p_t^n is the log price of an n-period discount bond.

where ${}_t y_{t+1}^{(1)}$ is the expected 1-period log yield for a discount bond in time period *t+1* conditional on time *t* information.

Given current yields for 1- and 2-period bonds (the yield curve), equation (1) can be used to back out an estimate of the bond market's expectation of the yield on 1-period bonds one period in the future: ${}_t y_{t+1}^{(1)} = 2y_t^{(2)} - y_t^{(1)}$.

Equation (1) can be generalized to *n*-periods:

$$y_t^n = \frac{y_t^{(1)} + {}_t y_{t+1}^{(1)} + \cdots + {}_t y_{t+n-1}^{(1)}}{n} \qquad (2)$$

Equation (2) implies that the yield curve consisting of interest rates on *1* through *n*-period bonds can be used to back out estimates of the sequence of expected interest rates on *1*-period bonds from *t+1* through *t+n-1* (called forward rates on *1*-period bonds).

If the EH held exactly, it would be straightforward to derive the expected path of future short-term interest rates implied by the current yield curve. But the EH does not hold exactly; there is a persistent (but time-varying) wedge or term premium between long-term rates and the average of expected short-term rates.[6]

$$y_t^n = \frac{y_t^{(1)} + {}_t y_{t+1}^{(1)} + \cdots + {}_t y_{t+n-1}^{(1)}}{n} + TP_t^{(n)} \qquad (3)$$

The term premium for a bond with a term to maturity *n* (denoted $TP_t^{(n)}$) is unobserved and reflects some combination of the following factors: compensation for the risk of holding long-term bonds, differences in liquidity across bonds of different maturities, investors' preferences for certain maturities over others, and biased expectations of future short-term interest rates. Researchers have developed various methods to estimate the term premium.

For most of the past five decades, the estimated term premium has been positive and increasing in the term to maturity (*n*).[7] The typical positive term premium is explained by the fact that for a

[6]The failure of the expectations hypothesis to explain movements in interest rates is well established. See, for example, Fama and Bliss (1987) and Campbell and Shiller (1991).

[7]A term premium can be defined with respect to any two securities that differ in their term to maturity. For this analysis, the term premium refers to the difference between the yield on the nominal 10-year Treasury note and the

given change in market interest rates, the prices of long-term securities vary by more than the prices of short-term securities, which implies there is more risk associated with holding long-term securities. The typically positive term premium reflects compensation for that risk and can account for the positive slope, on average, of the yield curve.

Since the 2007–2009 recession, the term premium on the 10-year Treasury note relative to the term premium on the one-month Treasury bill has declined from roughly 2 percentage points to negative 50 basis points. (A basis point is one one-hundredth of a percentage point.) Part of the explanation for that decline is that investors have increased their demand for long-term Treasury securities as a hedge against possible negative shocks to inflation and equity prices. Another contributing factor to the low term premium is the Federal Reserve's large-scale purchases of long-term securities through its quantitative easing programs.[8]

The presence of the term premium does not completely eliminate the possibility of extracting information about future expected movements in interest rates from the current yield curve. Given an estimated term premium ($\widehat{TP}_t^{(n)}$), equation (3) can be used to back out the sequence of expected short-term rates that are consistent with that estimated term premium and the current yield curve. Researchers have developed various methods to estimate the *current* term premium and the expected short-term rates contained in the yield curve.[9] For those methods to be usefully applied to forecasts of interest rates, it is necessary to combine the expected short-term rates with a forecast of the *future* term premium. For the forecast comparisons presented below, CBO generated a forecast of the long-term interest rate by combining the average of the expected short-term rates based on the method developed by Adrian, Crump, and Moench (ACM, 2013) with a forecast of the term premium based on a vector autoregression (VAR).[10]

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average expected yield on the nominal 28-day Treasury bill over the relevant 10-year period. The estimated term premium has been positive for most of the period from 1963 through 2015 (see Figure A-2 in the appendix).

[8]For further discussion of factors that have recently pushed down the term premium, see Congressional Budget Office, *The Budget and Economic Outlook: 2017 to 2027* (January 2017), www.cbo.gov/publication/52370.

[9]See, for example, Duffie and Kan (1996), Vasicek (1977), Cox, Ingersoll, and Ross (1985 a,b), Longstaff and Schwartz (1992 a,b), and Adrian, Crump, and Moench (2013).

[10] See the following section and the appendix for additional details.

Forecasting Methods

CBO compared the accuracy of the *Blue Chip*'s consensus forecasts of long-term interest rates with the accuracy of forecasts generated from several other methods. Three of the comparison methods incorporate information from the yield curve. The other methods serve as benchmarks for the *Blue Chip* consensus forecast and the forecasts generated from the yield curve. Researchers use benchmark forecasts to represent minimum standards for forecast accuracy. For *Blue Chip* forecasts and the forecasts generated from the yield curve to be of practical use, they should be at least as accurate as the benchmark forecasts.

Yield Curve Methods

CBO considered three forecasting methods based on the yield curve. The first method is a reduced-form vector autoregression based on the first three principal components estimated from the Treasury yield curve. The second and third methods are based on the expectations hypothesis.

Reduced-Form Method Based on the Yield Curve. The first three principal components of the Treasury yield curve roughly measure the level, slope, and curvature of the yield curve (see Litterman and Scheinkmann, 1991, and Cochrane and Piazzesi, 2005). CBO estimated a VAR consisting of the nominal long-term interest rate and the first three principal components: [11,12]

$$X_{t+h} = B(L)X_{t-1} + \varepsilon_t \qquad (4)$$

Where $X_t = \begin{bmatrix} i_t \\ PC1i_t \\ PC2i_t \\ PC3i_t \end{bmatrix}$,

$B(L)$ is the matrix of polynomials in the lag operator, $PCi_t, i = 1, \ldots, 3$ are the principal components, ε_t is the regression residual, h=0,… is the forecast horizon, and i_t is the nominal long-term interest rate.[13,14]

[11]CBO generated the yields on Treasury securities with terms to maturity ranging from 1 to 120 months using the parameters from Gurkaynak, Sack, and Wright (2006). Changes in the first principal component explain 98 percent of the variation in the nominal 10-year Treasury note rate over the 1961–2015 period.

[12]This method closely follows that used by Bliss (1997). See the appendix for additional details.

[13]The matrix of polynomials in the lag operator is a compact way of representing the relationship between each of the elements of the X vector and their past values.

The VAR measures past correlations between the long-term interest rate and the level, slope, and curvature of the yield curve, but it is only loosely connected to the expectations hypothesis. For example, a positive correlation between the slope of the yield curve and the long-term interest rate could be capturing some combination of expected increases in future rates and the forecastable part of the term premium (the two parts of the right-hand side of equation (3)). But the VAR method does not attempt to sort out that combination and simply relies on the assumption that past correlations will persist in the future.

Methods Based on the Expectations Hypothesis. As alternatives to the reduced-form approaches, CBO estimated two models based on the expectations hypothesis. The first method assumes the expectations hypothesis holds perfectly with a term premium of zero. Under that assumption, the forecast for the nominal 10-year Treasury note rate for horizon *h* is simply the average of the forecast rates from period *h* to *h+9*. For example, the forecast for the nominal 10-year Treasury note rate *h*-years ahead would be based on equation (2) pushed forward in time to begin in period *t+h*:

$$ {}_{t}y^{10}_{t+h} = \frac{{}_{t}y^{(1)}_{t+h} + {}_{t}y^{(1)}_{t+h+1} + \cdots + {}_{t}y^{(1)}_{t+h+9}}{10} \qquad (5) $$

Forecasts based on that method are labeled EH.

CBO also estimated a structural model of the yield curve based on the expectations hypothesis, modified to include an estimated term premium. This method produces separate estimates of the two terms on the right-hand side of equation (3)—the term premium and the sequence of expected future short-term interest rates. Estimates of the term premium are based on the ACM method.

CBO used the ACM method to separate the *current* term premium from the sequence of short-term interest rates. To produce a forecast of long-term interest rates, however, it is necessary to forecast the sequence of *future* term premiums and then combine those term premiums with

[14]Previous researchers have used similar techniques to characterize and forecast the yield curve. Bliss (1997) estimated a VAR using the first three principal components of the yield curve but focused on the estimated impulse responses rather than forecasting the yield curve. Diebold and Li (2006) estimated a VAR with three factors derived from the yield curve. Although their focus was on forecasting, they used a different technique (Nelson-Siegel) to derive the factors underlying the curve.

average expected future short-term rates from the ACM model. CBO used a vector autoregression to forecast the sequence of future term premiums and then added that sequence of forecasted term premiums to the average of the expected future short-term rates derived using the ACM method to arrive at a forecast for the nominal long-term interest rate.[15] The forecasts based on that method are labeled EHTP.

Benchmark Methods

CBO compared the accuracy of the interest rate forecasts from the *Blue Chip* consensus and from the three methods based on the yield curve with three different benchmark methods: a random walk (RW), an autoregressive moving average (ARMA) model of the long-term interest rate, and a simple linear forecast rule using the *Blue Chip*'s forecast of growth rates of nominal gross domestic product (GDP).

Random Walk. The simplest and most naïve forecast is the random walk forecast. The random walk forecast of the nominal interest rate at horizon $t+h$ is simply the value of the interest rate observed at date t. That benchmark serves as a minimum standard for forecast accuracy. To the extent that economic theory has value in forecasting, the forecasts based on theory should outperform the random walk forecast.

Autoregressive Moving Average. A slightly more sophisticated but still naïve method is the autoregressive moving average model. Simple ARMA models are often used as benchmarks in forecast comparisons because they are statistical, not economic, models that are based purely on the historical behavior of the series. The main difference between the random walk forecast and the ARMA forecast is that the ARMA forecast accounts for short-term persistence in the data being forecasted. As with the random walk forecast, ARMA forecasts are considered a minimum standard for accuracy.[16]

[15] CBO uses the curve consisting of yields on Treasury securities with terms to maturity ranging from one month to 10 years to estimate the sequence of short-term interest rates over the next decade. However, forecasts of the 10-year Treasury note rate require estimates of short-term interest rates for years 11 and beyond. For example, the forecast of the nominal 10-year Treasury note rate one year ahead requires a forecast of the short-term interest rates from one year ahead through 11 years ahead. To forecast the short-term interest rates for periods beyond the 10-year window, CBO uses an autoregression.

[16] The specific model chosen for those forecasts was an MA(2) based on in-sample fit over the monthly sample of nominal 10-year Treasury note rates between 1961 and 1984.

Nominal GDP Growth. The final benchmark is based on the *Blue Chip*'s forecast of the growth of nominal GDP. In a standard neoclassical growth model, the real (inflation-adjusted) interest rate roughly corresponds to the growth rate of real GDP.[17] By adding inflation, the standard neoclassical growth model also implies a rough correspondence between nominal interest rates and the growth of nominal GDP. Because the nominal GDP growth forecast is regularly reported as part of the *Blue Chip* consensus's semiannual forecast, it serves as a check on the accuracy of the rough correspondence implied by the neoclassical growth model.

A Comparison of Forecast Accuracy

CBO compared the accuracy of the *Blue Chip's* forecasts of the average annual nominal long-term interest rate, for horizons one through five years, over the full sample period and two subsample periods. The full sample comprised 57 semiannual *Blue Chip* forecasts published between March 1984 and March 2012. The subsample periods were 1984 through 1997 and 1998 through 2012.

The comparison forecasts based on the yield-curve methods were constructed as if in real time using only the data that were available when the *Blue Chip* produced each of its semiannual forecasts. All of the models were estimated using monthly observations from June 1961 through the relevant forecast jump-off date (February of each year for the *Blue Chip* forecast produced in March and September of each year for the *Blue Chip* forecast produced in October). The monthly forecasts were then averaged to produce annual averages. CBO produced the ARMA (and trivially the RW) forecasts in the same manner.

For the full sample of 57 forecasts, the *Blue Chip* consensus was generally as accurate (or more accurate) than the forecasts produced by the yield-curve methods—VAR, EH, and EHTP (see **Table 3**).[18] Compared with the benchmark methods, the *Blue Chip* consensus forecasts were also

[17]The relationship between the real interest rate and real GDP growth in the neoclassical growth model is approximate. In a standard Solow growth model, the real interest rate is equal to $\frac{\alpha}{s}(n + g + \delta)$ where α is capital's share, s is the fixed saving rate, n is the growth of labor input, g is the growth rate of labor productivity, and δ is the depreciation rate. The growth rate of real GDP in that model is simply $n + g$. In a standard optimal growth model with endogenous saving, $r = \frac{1}{\sigma}g + n + \theta$ where σ is the intertemporal elasticity of substitution in consumption and θ is the rate of time preference. The usefulness of nominal GDP as an input to forecasting nominal interest rates depends on the accuracy of those approximations as well as the accuracy of the forecast of nominal GDP growth.

[18]CBO evaluated relative forecast accuracy using the modified Diebold-Mariano (DM) test statistic. That statistic is the t-test on the difference in the squared errors of the two forecasts (see Diebold and Mariano, 1995). The modified

consistently more accurate than those based on the ARMA model. The RW and ARMA models produced smaller RMSEs than the *Blue Chip* consensus at the longer forecast horizons (years 3 through 5), but the differences were not statistically significant. Using the *Blue Chip* consensus forecast of nominal GDP growth in place of the interest rate forecast would have produced a (significantly) smaller RMSE at the 5-year-ahead horizon.

Table 3. RMSEs of Seminannual Forecasts, 1984 to 2012

		Yield-Curve Models			Benchmark Models		
Forecast Horizon	*Blue Chip*	VAR	EH	EHTP	RW	ARMA	GDP
1	0.69	0.71	0.82	0.87	0.74	0.72	1.74
2	1.22	1.3	1.47	1.51	1.25	1.22	1.44
3	1.46	1.6	1.75	1.74	1.36	1.35	1.48
4	1.59	1.87	1.98	1.96	1.44	1.48	1.49
5	1.8	2.18	2.26	2.20	1.55	1.67	1.56**

Sample size = 57, ** significantly smaller than *Blue Chip*'s RMSE at the 0.05 level based on two-tailed tests using the student's-t distribution (see Harvey, Leybourne, and Newbold, 1997).

Forecasters were largely surprised by the persistent downward movement in long-term interest rates throughout the 1984–2012 period, especially toward the latter half of the period.[19] CBO tested whether the relative accuracy of the various forecasting methods changed over the two halves of the sample. Some of the models based on the yield curve produced more accurate forecasts in the later sample than in the earlier sample (for the EH model at all horizons and the VAR and EHTP models at shorter horizons), CBO found. But even with those improvements, none of those models produced significantly more accurate forecasts than the *Blue Chip*

DM test (see Harvey, Leybourne, and Newbold, 1997) corrects for small sample bias by multiplying the DM test statistic by $\sqrt{\frac{T+1-2h+h(h-1)}{T}}$, where T is the sample size and h is the forecast horizon.

[19] CBO recently updated its analysis of its forecasting record as well as the forecasting records of the *Blue Chip* consensus and the Administration (as published in the annual budget documents prepared by the Office of Management and Budget). That analysis found that across all three forecasters, interest rate forecasts have tended to be more biased and less accurate than forecasts of other economic variables. See Congressional Budget Office, *CBO's Economic Forecasting Record: 2017 Update* (October 2017), www.cbo.gov/publication/53090.

consensus over the 1998–2012 period (see **Table 4** and **Figure 2**). Among the benchmark forecasts, however, the ARMA and RW methods produced significantly more accurate forecasts than the *Blue Chip* consensus at all horizons over the later sample.

The RMSE results indicate that models based on the yield curve would not have produced significantly more accurate forecasts in real time over the full sample and over the two subsamples examined in this analysis. The finding that the benchmark methods produced more accurate forecasts (especially over the later sample) reflects the fact that benchmark forecasts temper the rise in interest rates (or, in the case of the random walk, hold interest rates constant) relative to the yield-curve methods. In an environment with persistently falling interest rates, methods that forecast less of a rise in interest rates or no rise at all will outperform methods that assume that interest rates will rise back toward historical averages.[20]

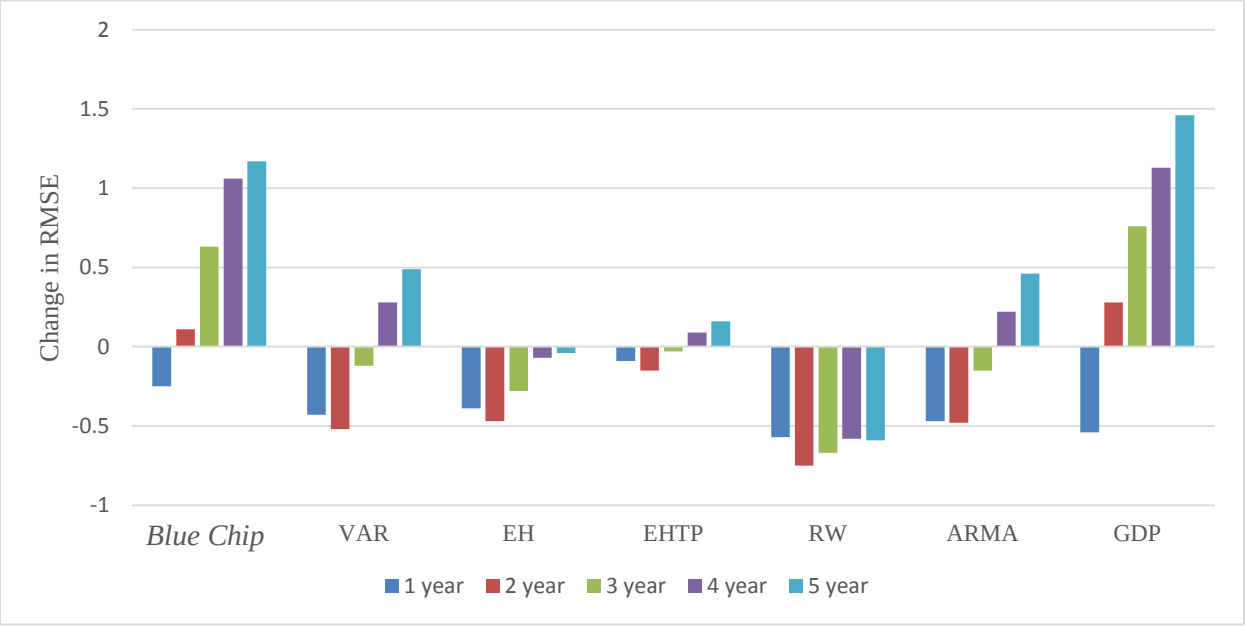
[20]An economic data series is said to be stationary if it exhibits a constant mean and constant covariance structure throughout time. Many of the models examined in this study (such as the VAR, EHTP, and ARMA models) perform poorly when the data they are applied to are nonstationary because those models are constructed to produce forecasts that revert back to the historical mean of the series. The average nominal 10-year Treasury note rate declined steadily throughout the period examined here. Thus, any model that assumes stationarity when used to forecast the nominal 10-year Treasury note rate will fail to anticipate changes in the mean of the series.

Table 4. RMSEs of Seminannual Forecasts for Subsamples 1984–1997 and 1998–2012

			Yield-Curve Models			Benchmark Models		
Forecast Horizon	Sample Period	*Blue Chip*	VAR	EH	EHTP	RW	ARMA	GDP
1	1984–1997	0.81	0.89	1	0.92	0.97	0.92	2
	1998–2012	**0.56**	**0.46**‡	**0.61**	**0.83**	**0.40****	**0.45****	**1.46**
2	1984–1997	1.16	1.54	1.69	1.58	1.57	1.44	1.29
	1998–2012	1.27	**1.02**	**1.22**	**1.43**	**0.82***	**0.96***	**1.57**
3	1984–1997	1.11	1.66	1.89	1.75	1.66	1.42	1.05
	1998–2012	1.74	**1.54**	**1.61**	1.72	**0.99****	**1.27***	1.81
4	1984–1997	0.96	1.73	2.02	1.91	1.7	1.36	0.81
	1998–2012	2.02	2.01	**1.95**	2.00	**1.12****	1.58*	1.94
5	1984–1997	1.11	1.92	2.28	2.12	1.83	1.42	0.64**
	1998–2012	2.28	2.41	**2.24**	2.28	**1.24****	1.88*	2.10**

Sample sizes were 28 for the 1984–1997 subsample and 29 for the 1998–2012 subsample. Instances in which the root mean square error (RMSE) was smaller in the 1998–2012 subsample than in the 1984–1997 subsample are shown in bold. Significance levels are reported for the RMSEs that are significantly smaller than the *Blue Chip* consensus's RMSE and are based on two-tailed tests using student's-t distribution (see Harvey, Leybourne, and Newbold, 1997); ‡ denotes significance at the .10 level, * denotes significance at the 0.05 level, ** denotes significance at the 0.01 level.

Figure 2. Change in RMSE, 1984–1997 to 1998–2012



Each bar represents the difference between the root mean square error (RMSE) in the earlier subsample (1984 to 1997) and the later subsample (1998 to 2012) for a particular forecast and horizon.

The bias estimates produced by the various forecasting methods followed a pattern similar to that of the RMSE estimates (see **Table 5**). The VAR, ARMA, and GDP methods produced slightly less bias than the *Blue Chip* consensus at all horizons in the later sample period (1998 to 2012). The EH also produced slightly smaller bias than the *Blue Chip* consensus over the later sample, but only for horizons 2 through 5 years ahead. The RW forecasts were substantially less biased than those of the *Blue Chip* consensus in both the full sample and (especially) the later sample. In some cases, the bias produced by the RW forecasts was less than one-third the size of the bias contained in the *Blue Chip* consensus forecast.

Table 5. Statistical Bias

Horizon	Sample	*Blue Chip*	VAR	EH	EHTP	RW	ARMA	GDP
1	1984–2012	0.29**	0.20*	0.44**	0.54**	0.15	0.19*	-0.75*
		(0.08)	(0.10)	(0.09)	(0.1)	(0.10)	(0.09)	(0.34)
	1984–1997	0.23‡	0.24	0.48**	0.45**	0.25	0.21	-1.76**
		(0.13)	(0.18)	(0.16)	(0.15)	(0.18)	(0.17)	(0.21)
	1998–2012	0.36**	0.16‡	0.4**	0.63**	0.06	0.18‡	0.23
		(0.09)	(0.09)	(0.11)	(0.14)	(0.09)	(0.09)	(0.37)
2	1984–2012	0.85**	0.69**	1**	1.11**	0.48*	.58**	-0.02
		(0.17)	(0.20)	(0.19)	(0.18)	(0.21)	(0.19)	(0.35)
	1984–1997	0.65*	0.72‡	1.1**	1.03**	0.68‡	0.57	-1.07**
		(0.25)	(0.36)	(0.33)	(0.3)	(0.37)	(0.34)	(0.22)
	1998–2012	1.04**	0.66**	0.91**	1.19**	0.27	0.59**	0.99*
		(0.19)	(0.21)	(0.22)	(0.21)	(0.19)	(0.19)	(0.38)
3	1984–2012	1.18**	1.12**	1.41**	1.47**	0.71**	0.87*	0.38
		(0.20)	(0.24)	(0.2)	(0.19)	(0.23)	(0.21)	(0.36)
	1984–1997	0.78**	1.04*	1.46**	1.36**	0.92*	0.74**	-0.71**
		(0.22)	(0.38)	(0.32)	(0.32)	(0.40)	(0.35)	(0.24)
	1998–2012	1.57**	1.20**	1.37**	1.57**	0.5*	1.00**	1.42**
		(0.23)	(0.29)	(0.24)	(0.19)	(0.24)	(0.22)	(0.37)
4	1984–2012	1.33**	1.53**	1.76**	1.75**	0.91**	1.13**	0.66‡
		(0.21)	(0.23)	(0.17)	(0.17)	(0.22)	(0.20)	(0.34)
	1984–1997	0.74**	1.31**	1.73**	1.6**	1.10**	0.86**	-0.39**
		(0.16)	(0.32)	(0.25)	(0.3)	(0.35)	(0.28)	(0.2)
	1998–2012	1.91**	1.74**	1.79**	1.91**	0.74**	1.40**	1.67**
		(0.23)	(0.31)	(0.22)	(0.17)	(0.25)	(0.23)	(0.33)
5	1984–2012	1.55**	1.95**	2.1**	2.05**	1.15**	1.42**	0.89**
		(0.22)	(0.21)	(0.14)	(0.16)	(0.20)	(0.18)	(0.32)
	1984–1997	0.91**	1.67**	2.07**	1.9**	1.37**	1.07**	-0.13
		(0.15)	(0.25)	(0.2)	(0.26)	(0.31)	(0.22)	(0.15)
	1998–2012	2.16**	2.23**	2.13**	2.2**	0.94**	1.75**	1.88**
		(0.25)	(0.30)	(0.2)	(0.18)	(0.24)	(0.22)	(0.32)

Each cell in the table shows the average forecast error for the forecast horizon and sample period listed in the far left columns. Beneath the average error is the Newey-West standard error. Positive numbers indicate that the forecasted value was higher than the actual value, on average. The asterisks indicate statistical significance corresponding to the null hypothesis that the bias is zero: ‡ denotes significance at the .10 level, * denotes significance at the 0.05 level, and ** denotes significance at the 0.01 level.

Does the Yield Curve Contain Information That Would Have Improved the *Blue Chip*'s Forecasts?

In the 1998–2012 subsample, a forecast based on the random walk (that is, assuming a constant interest rate over the entire five-year horizon) would have produced forecasts that were more accurate and less biased than those of the *Blue Chip* consensus. It is still possible, however, that forecasts based on the yield curve would provide information that could be used to improve on the *Blue Chip*. In particular, if the *Blue Chip* consensus forecasts and the forecasts based on the yield curve captured different (complementary rather than redundant) information about future interest rates, then combining those forecasts could lead to improvements in forecast accuracy compared with using a single "best" forecast.[21]

To investigate that possibility, CBO measured the accuracy of combined forecasts that were constructed by taking the simple average of pairs of forecasts analyzed here (see **Table 6**).[22] Over the full sample and the 1984–1997 subsample period, several of the combination forecasts (shown in bold) had lower RMSEs than the *Blue Chip* consensus alone. In two instances—the *Blue Chip* consensus combined with nominal GDP growth at horizons 4 and 5 years—the RMSE was significantly lower than the corresponding RMSE for the *Blue Chip* consensus forecast. When the *Blue Chip* consensus forecast was combined with the ARMA or RW forecast over the second subsample period, the resulting RMSE was lower than the RMSE from the *Blue Chip* forecast. But even in those instances, the RMSEs for the combined forecasts were larger than the RMSEs for the individual (ARMA or RW) forecasts.

[21]See Timmerman (2006) for a review of the literature on combining forecasts.

[22]An alternative to averaging is to combine forecasts using weights estimated by regressing actual outcomes on past forecasts. CBO chose the simple average instead of estimated weights, for two reasons. First, using weights estimated from the sample of forecasts would be inconsistent with the real-time nature of the other forecasts compared in this analysis. A forecaster working in real time would not have had those estimated weights when each forecast was made. Second, estimated weights are often imprecise (because of sampling error, especially for small samples), and combining forecasts using a simple average typically results in a forecast that is as good or better than one made using estimated weights [see Clemen (1989), Stock and Watson (2001, 2004), and Timmerman (2006)]. In practice, the gains from estimating the weights are typically not large enough (relative to simple averaging) to outweigh the estimation error. Elliott (2011) explores that trade-off and provides theoretical bounds on the size of the gain from estimating the weights when combining forecasts.

Table 6. RMSEs of Combined Forecasts for the Full Sample and Subsamples

Horizon	Sample Period	*Blue Chip*	VAR	EH	EHTP	RW	ARMA	GDP
	1984–2012	0.69	**0.66**	**0.68**	0.71	**0.67**	**0.67**	1.15
1	1984–1997	0.81	0.81	**0.78**	**0.74**	0.83	0.82	1.36
	1998–2012	0.56	**0.47**	0.57	0.68	**0.45****	**0.49****	0.91
	1984–2012	1.22	**1.11**	**1.20**	1.23	**1.07**	**1.10**	**1.18**
2	1984–1997	1.16	**1.14**	1.17	**1.09**	1.17	**1.12**	**0.92**
	1998–2012	1.27	**1.08**	**1.23**	1.34	**0.97****	**1.09****	1.38
	1984–2012	1.46	**1.38**	1.46	1.46	**1.22**	**1.30**	**1.37**
3	1984–1997	1.11	1.16	1.24	1.14	1.17	**1.08**	**0.80**
	1998–2012	1.74	**1.57**	**1.66**	**1.72**	**1.27****	**1.48****	1.75
	1984–2012	1.59	1.57	1.62	1.61	**1.29**	1.42	**1.47****
4	1984–1997	0.96	1.04	1.14	1.06	1.04	**0.90**	**0.64****
	1998–2012	2.02	**1.96**	**1.97**	**2.00**	**1.48****	**1.78***	**1.97**
	1984–2012	1.8	1.84	1.85	1.83	**1.45**	**1.62**	**1.61****
5	1984–1997	1.11	1.18	1.32	1.22	1.15	**0.98**	**0.62****
	1998–2012	2.28	2.30	**2.25**	**2.26**	**1.69****	**2.06****	**2.18****

Sample sizes were 57 for the 1984–2012 sample, 28 for the 1984–1997 subsample, and 29 for the 1998–2012 subsample. The column labeled *Blue Chip* reports the root mean square error (RMSE) for the *Blue Chip* consensus forecast of the nominal 10-year Treasury note rate. The remaining columns report the RMSE resulting from combining the *Blue Chip* consensus forecast with the forecast listed in the column heading using a simple average. Instances in which the RMSE for the combined forecasts was smaller than the RMSE for the *Blue Chip* consensus forecast are shown in bold. Significance levels are reported for the RMSEs that are significantly smaller than the *Blue Chip* consensus's RMSE and are based on two-tailed tests using the student's-t distribution (see Harvey, Leybourne, and Newbold, 1997); ǂ denotes significance at the 0.10 level, *denotes significance at the 0.05 level, **denotes significance at the 0.01 level.

In several instances, combining forecasts reduced the bias relative to the individual forecast results reported in Table 5 (see **Table 7**). For all horizons and forecasts, bias was positive in the later sample. Except for the forecasts based on the combination of the *Blue Chip* consensus and nominal GDP growth at the one-year horizon, bias was positive and statistically significant in the later sample for all horizons and forecasts. Over the subsample 1997–2012, the biases in the random walk forecasts (Table 5) were smaller than the biases reported for all of the combination forecasts at each horizon.

Table 7. Statistical Bias in Combined Forecasts

Horizon	Sample Period	*Blue Chip*	VAR	EH	EHTP	RW	ARMA	GDP
1	1984–2012	0.29**	0.24**	0.37**	0.42**	0.22**	0.24**	-0.23
		(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.08)	(0.19)
	1984–1997	0.23^{ǂ}	0.23	0.35*	0.33*	0.23	0.21	-0.77**
		(0.13)	(0.15)	(0.14)	(0.13)	(0.15)	(0.15)	(0.13)
	1998–2012	0.36**	0.26**	0.38**	0.50**	0.21**	0.27**	0.30
		(0.09)	(0.07)	(0.09)	(0.11)	(0.08)	(0.09)	(0.21)
2	1984–2012	0.85**	0.76**	0.92**	0.98**	0.66**	0.71**	0.41^{ǂ}
		(0.17)	(0.16)	(0.17)	(0.16)	(0.17)	(0.17)	(0.24)
	1984–1997	0.65*	0.67*	0.86**	0.83**	0.66*	0.60^{ǂ}	-0.22
		(0.25)	(0.29)	(0.28)	(0.25)	(0.30)	(0.28)	(0.19)
	1998–2012	1.04**	0.85**	0.98**	1.12**	0.66**	0.82**	1.02**
		(0.19)	(0.16)	(0.20)	(0.20)	(0.18)	(0.18)	(0.28)
3	1984–2012	1.18**	1.14**	1.29**	1.31**	0.93**	1.02**	0.77**
		(0.20)	(0.19)	(0.18)	(0.18)	(0.18)	(0.19)	(0.27)
	1984–1997	0.78**	0.89**	1.10**	1.05**	0.83**	0.74**	-0.01
		(0.22)	(0.28)	(0.25)	(0.24)	(0.29)	(0.26)	(0.20)
	1998–2012	1.57**	1.39**	1.47**	1.57**	1.04**	1.28**	1.50**
		(0.23)	(0.21)	(0.23)	(0.20)	(0.21)	(0.21)	(0.29)
4	1984–2012	1.33**	1.42**	1.54**	1.53**	1.11**	1.22**	0.99**
		(0.21)	(0.19)	(0.17)	(0.17)	(0.17)	(0.19)	(0.27)
	1984–1997	0.74**	1.01**	1.22**	1.15**	0.90**	0.78**	0.16
		(0.16)	(0.22)	(0.19)	(0.21)	(0.23)	(0.21)	(0.17)
	1998–2012	1.91**	1.83**	1.85**	1.91**	1.32**	1.65**	1.79**
		(0.23)	(0.22)	(0.21)	(0.19)	(0.21)	(0.21)	(0.28)
5	1984–2012	1.55**	1.74**	1.82**	1.79**	1.34**	1.47**	1.21**
		(0.22)	(0.19)	(0.16)	(0.17)	(0.16)	(0.19)	(0.27)
	1984–1997	0.91**	1.27**	1.47**	1.39**	1.12**	0.98**	0.37*
		(0.15)	(0.18)	(0.16)	(0.18)	(0.21)	(0.17)	(0.14)
	1998–2012	2.16**	2.20**	2.15**	2.18**	1.55**	1.95**	2.02**
		(0.25)	(0.22)	(0.22)	(0.20)	(0.21)	(0.22)	(0.28)

Sample sizes were 57 for the 1984–2012 sample, 28 for the 1984–1997 subsample, and 29 for the 1998–2012 subsample. The column labeled *Blue Chip* reports the average forecast error for the *Blue Chip* consensus forecast of the nominal 10-year Treasury note rate. The remaining columns report the average forecast error resulting from combining the *Blue Chip* consensus forecast with the forecast listed in the column heading using a simple average. Beneath the average error is the Newey-West standard error. Positive numbers indicate that the forecasted value was higher than the actual value, on average. The asterisks indicate statistical significance corresponding to the null hypothesis that the bias is zero: ǂ denotes significance at the 0.10 level, * denotes significance at the 0.05 level, ** denotes significance at the 0.01 level.

Conclusion and Next Steps

This analysis has two main findings. The first is that compared with the *Blue Chip* consensus, Treasury debt markets did not forecast with greater accuracy the decline in long-term interest

rates over the past three decades. Over the full sample, none of the methods based on the yield curve and none of the benchmark methods produced more accurate forecasts than the *Blue Chip* consensus. In the context of the yield-curve models examined in this analysis, the answer to the question of whether bond market participants did a better job anticipating the persistent decline in long-term interest rates is "no."

The second main finding is that the forecasts based on the random walk model of interest rates were in general more accurate and less biased than those of the *Blue Chip* consensus—especially over the most recent subsample period of 1998 to 2012. Although forecasters are unlikely to abandon their structural models in favor of the naïve RW forecast, those results suggest that forecasters should reexamine those models to determine which factors have been pushing interest rates back up toward historical levels (and away from the RW forecast) in recent years. One possible source of bias in those models is the term premium, which some analysts have argued is likely to remain suppressed relative to its historical average.[23]

Although the yield-curve-based models examined in this analysis did not outperform the *Blue Chip* consensus, there are other possibilities to explore. In particular, the accuracy of the forecasts produced by the EHTP method depends critically on the accuracy of the forecasts of the term premium. The method employed here relies on past yield curves to forecast the term premium, but there is some debate in the finance literature about whether the information set used to forecast the term premium should contain variables other than the yield curve (such as real GDP growth and inflation).[24] One avenue to explore in future research is whether the forecasts produced from the EHTP model can be improved by including such macroeconomic information.[25]

And, finally, it is important to note that the forecast evaluations in this analysis covered a period when long-term interest rates trended downward, on average. It is not necessarily the case that

[23]That argument is partly based on the increased hedging properties of long-term Treasury securities. Before the early 2000s, the correlation between the price of equities (stocks) and the price of Treasury securities (bonds) tended to be positive. Since that time, the correlation has been negative, which implies that Treasury bonds are now a better hedge against movements in equity prices. The increased desirability to hold Treasury securities as a hedge might be contributing to the low term premium. Moreover, to the extent that well-anchored inflation expectations have contributed to the negative correlation between stock and bond prices (because few inflation surprises would cause both prices to move in the same direction), the low term premium is likely to persist.
[24]See Bauer and Rudebusch (2015) and Bauer and Hamilton (2017).
[25]One downside of such a method is that it would require forecasts of the macroeconomic inputs.

the most accurate forecast models in a period of persistently falling interest rates will also be the most accurate when interest rates are no longer consistently falling.

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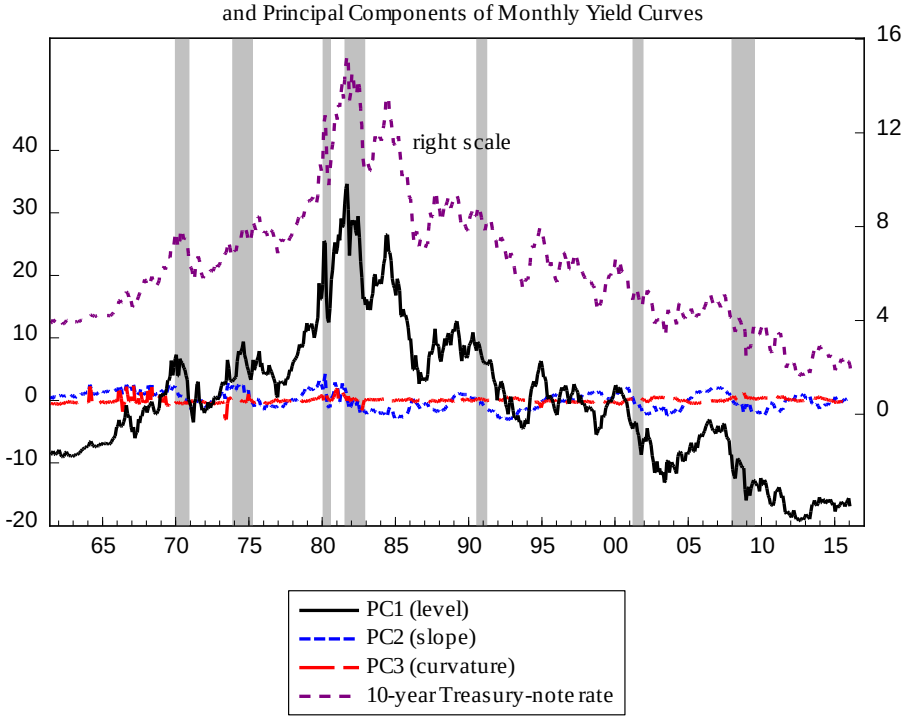
Appendix: Yield Curve Models

The Congressional Budget Office analyzed the accuracy of forecasts based on three methods that rely on information from the Treasury yield curve. The first method (the vector autoregression, or VAR) is based on the first three principal components estimated from the monthly Treasury yield curves. CBO generated the yields on Treasury securities with terms to maturity ranging from 1 to 120 months using the parameters from Gurkaynak, Sack, and Wright (GSW, 2006).[26]

The macroeconomics finance literature interprets the first three principal components of the yield curve as measures of its level, slope, and curvature at each point in time (see Cochrane and Piazzesi, 2005). Figure A-1 shows CBO's estimates of the first three principal components using the full sample (1961–2015), along with the nominal 10-year Treasury note rate (right scale). Changes in the first principal component explain 98 percent of the variation in the nominal 10-year Treasury note rate over the 1961–2015 period.

Figure A-1. 10-Year Treasury Note Rate
and Principal Components of Monthly Yield Curves



The second method is based on the expectations hypothesis (EH). The expectations hypothesis assumes that investors are indifferent between holding an *n*-period bond to maturity and holding a sequence of one-period bonds in each of the next *n* periods. For example, suppose an investor

[26] For the full set of yield curve parameters, see Refet S. Gurkaynak, Brian Sack, and Jonathan H. Wright, *The U.S. Treasury Yield Curve: 1961 to the Present*, Working Paper 2006-28, Finance and Economics Discussion Series (Federal Reserve Board, Washington, D.C., 2006), https://go.usa.gov/xRE94.

wishes to purchase a bond to hold for one month. That investor faces a choice: either purchasing a long-term bond at the beginning of the month and selling it at the end of the month or purchasing a bond with a term to maturity of one month. If investors in general are indifferent between those two options, then buying and selling in the markets for short- and long-term bonds will cause the expected returns for both options to equalize.

CBO constructed the EH forecasts by first calculating the sequence of short-term (one-period) rates implied by the yield curve and then averaging those short-term rates over 10 years as described by equation (2). The EH method assumes that there is no term premium. (The term premium is the additional return that investors require as compensation for holding a long-term bond instead of a one-period bond.)

The third method considered in this analysis is based on the expectations hypothesis of interest rates modified to include an estimated term premium.

As noted in the text, the expected returns on long-term bonds held for one period and one-period bonds tend not to equalize—there is a time-varying term premium. Researchers estimate the time-varying term premium by estimating the expected difference between holding an *n*-period bond for one period and holding a one-period bond. That expected difference, which is called the expected excess holding period return, is a measure of the term premium.

Estimating the term premium involves three steps.

- Step 1 is to estimate the first five principal components of the monthly yield curves generated using the GSW parameters as described above.[27]
- Step 2 is to model the principal components using a VAR (with lag length = 1) and then regress the realized excess holding period returns on the fitted values and the residuals from the VAR to obtain separate estimates of the expected and unexpected excess holding period returns.
- Step 3 is to use the cross-section of excess holding period returns (by term to maturity) to estimate the price of (term) risk and then impose a zero-arbitrage condition on the estimates of the expected excess returns and the price of risk to back out estimates of the expected short-term (risk-free) rates and the term premium.

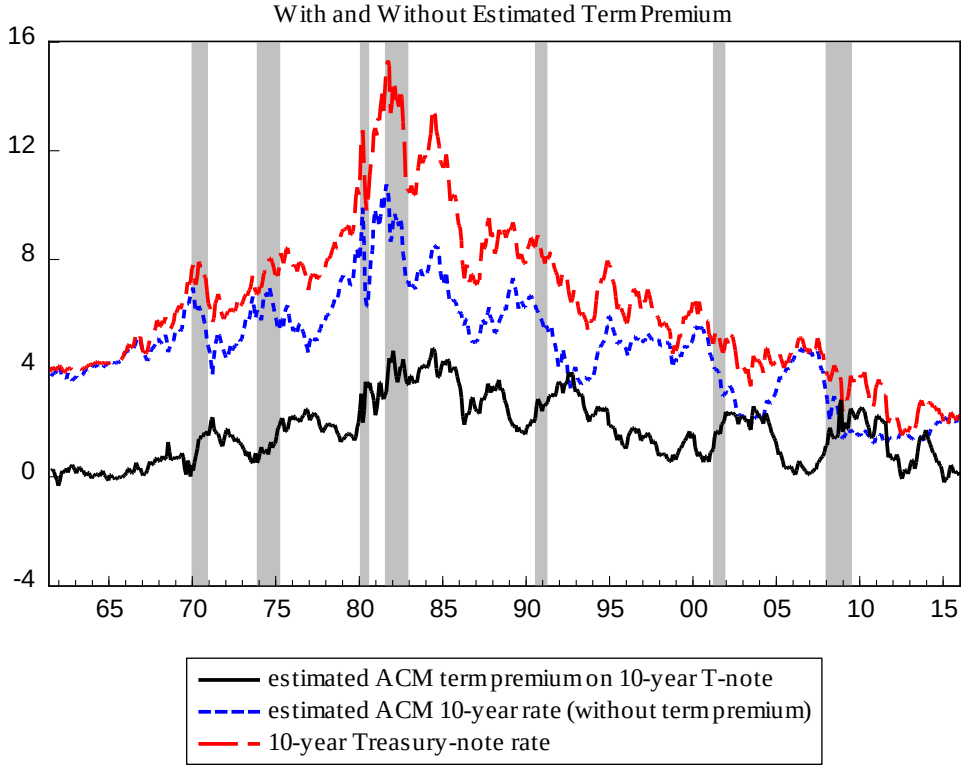
For the forecast comparisons in the main text, CBO using the data available at each date that *Blue Chip* completed its forecasts. Using the entire sample, the resulting estimates of the term premium, the 10-year Treasury note rate without the term premium, and the actual 10-year Treasury note rate are presented in Figure A-2, below.

To produce a forecast based on the Adrian, Crump, and Moench (ACM) model, CBO replaced the *current* term premium estimated at each date with a *forecast* of the term premium and then

[27]CBO chose the five-factor model because that was the benchmark model estimated in Adrian, Crump, and Moench (2013).

combined that forecast with the average of the short-term interest rates implied by the current yield curve. The ACM model produced estimates of the short-term (risk-free) interest rates over the period starting with the forecast jump-off date (February and September of each year in 1984 through 2012) and running through the 10-year period after that jump-off date. Thus, to forecast the 10-year Treasury note rate for periods beyond the current jump-off date requires estimates of both the short-term (risk-free) rates and the term premium beyond the 10-year window. CBO used a simple autoregressive model to forecast the short-term (risk-free) rates and a VAR to forecast the term premium consisting of the estimated term premiums for annual maturities 1 through 10 to forecast the term premium beyond the 10-year window.[28]

Figure A-2. 10-Year Treasury Note Rate
With and Without Estimated Term Premium



[28] An alternative method would be to forecast all of the parameters used in the ACM model to estimate the term premium at each date and construct the forecasted term premium using the forecasted parameters over various horizons.

Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return

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I. Introduction

Shareholder required rates of return play key roles in establishing economic criteria for resource allocation in many corporate and regulatory decisions. Theory dictates that such returns should be forward-looking return requirements that take into account the risk of the specific equity investment.

Estimation of such returns, however, presents numerous and difficult problems. Although theory clearly calls for a forward-looking required return, investigators, lacking a superior alternative, often resort to averages of historical realizations. One primary example is the determination of equity required return as a "least risk" rate plus a risk premium where an equity risk premium is calculated as an average of past differences between equity returns and returns on debt instruments. The historical studies of Ibbotson *et al.* [9] have been used frequently to implement this approach.[1] Use of such historical risk premia assumes that past realizations are a good surrogate for future expectations and that risk premia are roughly constant over time. Additionally, the choice of a time period over which to average data under such a procedure is essentially arbitrary. Carleton and Lakonishok [3] demonstrate empirically some of the problems with such historical premia when they are disaggregated for different time periods or groups of firms.

Recently Brigham, Shome, and Vinson [2] surveyed work on developing *ex ante* equity risk premia with particular emphasis on regulated utilities. They presented their own risk premia estimates, which make use of financial analysts' forecasts as surrogates for investor expectations.

The current paper follows an approach similar to Brigham *et al.* and derives equity required returns and risk premia using publicly available expectational

Thanks go to Ed Bachmann, Rich Harjes, and Hamid Mehran for computational assistance and to Bill Carleton, Pete Crawford, and Steve Osborn for many discussions. I gratefully acknowledge financial support from the UNC Business Foundation and the Pogue Foundation and thank Bell Atlantic for supplying data for this project. Finally, I thank colleagues at UNC for their helpful comments.

[1] Many leading texts in financial management use such historical risk premia to estimate a market return. See for example, Brealey and Myers [1]. Often a market risk premium is adjusted for the observed relative risk of a stock.

data. The estimation makes use of dividend growth models but incorporates expected rather than historical growth rates. A consensus forecast of financial analysts is used as a proxy for investor expectations. While Brigham *et al.* focus on utility securities, this paper also provides estimates of risk premia for a broad market index. Equity risk premia for both the market and for utilities are shown to vary over time with changes in the perceived riskiness of corporate activity relative to U.S. government bonds. In addition, the estimated risk premia at any given time are shown to vary across groups of stocks. The paper also provides results using the dispersion of analysts' forecasts as an *ex ante* proxy for equity risk.

Section II discusses related literature on financial analysts' forecasts (FAF) and the estimation of required returns using such forecasts. In Section III models and data are discussed. Following a comparison of the results to those of earlier studies (including historical risk premia), the estimates are subjected to economic tests of both their time-series and their cross-sectional characteristics in Section V. Finally, conclusions are offered.

II. Background and Literature Review

In finance, it is often convenient to use the notion of a shareholder's required rate of return. Such a rate (k) is the minimum level of expected return necessary to compensate the investor for bearing risks and receiving dollars in the future rather than in the present. In general, k will depend on returns available on alternative investments (*e.g.*, bonds or other equities) and the riskiness of the stock. To isolate the effects of risk it is often useful (both theoretically and empirically) to work in terms of a risk premium (rp), defined as

$$rp = k - i, \qquad (1)$$

where i = required return for a zero risk investment. Theoretically, i is a risk free rate, though empirically its proxy (*e.g.*, yield to maturity on a government bond) is only a "least risk" alternative that is itself subject to risk.[2] While models such as the capital asset pricing model offer explicit methods for varying risk premia across securities, they provide little practical advice on establishing some benchmark market risk premium. Other models, such as the dividend growth model (hereafter referred to as the discounted cash flow, or DCF, model), can be used to provide direct estimates of k, and hence implied values of rp, but are silent on how rp ought to vary across firms. In this paper DCF models are used to establish risk premia both for the market and for utility stocks. Since the DCF analysis uses a consensus measure of FAF of earnings as a proxy for investor expectations, a brief review of research on FAF is appropriate.

A. Literature on FAF

Much of the burgeoning literature on properties of FAF is surveyed by Givoly and Lakonishok [8]. Of primary importance for this work is the relationship between FAF and investor expectations that determine stock prices. Such forecast data are readily available. That they are used by investors is evidenced by the commercial viability of services that provide such forecasts and by the results of studies of investors' behavior (Touche, Ross and Company [16], Stanley, Lewellen and Schlarbaum [15]). Moreover, a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices. Such studies typically employ a consensus measure of FAF calculated as a simple average[3] of forecasts by individual analysts. Elton, Gruber, and Gultekin [5] show that stock prices react more to changes in analysts' forecasts of earnings than they do to changes in earnings themselves, suggesting the usefulness of FAF as a surrogate for market expectations. In an extensive NBER study using analysts' earnings forecasts, Cragg and Malkiel [4, p. 165] conclude "the expectations formed by Wall Street professionals get quickly and thoroughly impounded into the prices of securities. Implicitly, we have found that the evaluations of companies that analysts make are the sorts of ones on which market valuation is based." Updating Cragg and Malkiel's work, Vander Weide and Carleton [17] recently compare consensus FAF of earnings growth to 41 different historical growth measures.[4] They con-

[2]In this development the effects of tax codes and inflation on required returns are ignored.

[3]Mayshar [14] discusses the problems of explaining equilibrium prices of securities when there is divergence of opinion among investors. One issue is whether it is the expectation of the marginal investor or the average investor that determines security prices. Mayshar shows that, in general given divergence of opinion and trading costs, not all investors trade in all assets and that equilibrium prices and the identity of investors trading in each asset are jointly determined. In this sense, equilibrium prices can be considered as "determined simultaneously by the average and marginal investors."

[4]Both Cragg and Malkiel [4] and Vander Weide and Carleton [17] show that an average measure of analysts' forecasts of growth in earnings is powerful in explaining cross-sectional variation in price earnings ratios of stocks.

clude that "there is overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically-oriented growth measures in predicting the firm's stock price . . . consistent with the hypothesis that investors use analysts' forecasts, rather than historically-oriented growth calculations, in making stock buy and sell decisions." [17, p. 15].

B. Use of FAF to Estimate Equity Required Returns

Given the demonstrated relationship of FAF to equity prices and the direct theoretical appeal of expectational data, it is no surprise that FAF have been used in conjunction with DCF models to estimate equity return requirements. Typically such approaches have estimated an *ex ante* risk premium (rp) calculated as the difference between required return and a least risk rate as shown in Equation (1).

Malkiel [13] estimated such risk premia for the Dow Jones Industrial Index using a nonconstant growth version of the DCF model. Initial years of growth were based on Value Line's five-year earnings growth forecasts with subsequent growth approaching a long-run real national growth rate of 4%. More recently, Brigham, Vinson, and Shome [2] used a two stage DCF growth model to estimate *ex ante* risk premia for electric utilities and the Dow Jones Industrial Index. For the period 1966–1984, they report annual risk premia for both Dow Jones Industrial and Electric Indices using Value Line's forecasts. Beginning in 1980 they report monthly risk premia for electric utilities with the source of FAF varying over time; starting with Value Line, adding Merrill Lynch and Salomon Brothers in 1981 and finally, in mid-1983, adding IBES data. IBES (Institutional Broker's Estimate System) is a collection of analysts' forecasts and is discussed in the next section. The resultant risk premia vary over time. In addition, Brigham *et al.* present evidence that their estimated risk premia vary cross-sectionally with a stock's risk (as proxied by bond rating) and over time with the level of interest rates. FAF also have been used in conjunction with DCF models by a number of expert witnesses in rate of return determination for regulated utilities. Recently, the Federal Communications Commission [6] tentatively endorsed the use of consensus FAF in DCF determinations of required return on equity.[5]

This paper adds to earlier work in a number of important respects. First, while Malkiel and Brigham *et al.* focus on electric utilities or the Dow Jones Industrial Index, this paper estimates risk premia for a broadly defined market index — the Standard and Poor's 500. Thus, the results are directly comparable to historical "market" risk premia typically estimated on a similar sample of stocks. Second, the study uses a large sample of FAF (beginning in 1982 when the necessary data first became available). This provides the ability to use a consensus measure of expectations as would be suggested by financial theory. Third, the results show that the derived risk premia change over time and that these changes are related to proxies for risk, which would be expected to be associated with equity risk premia. Although such changes have been noted by earlier studies (*e.g.*, Brigham *et al.*), there is little work explaining the patterns of change. Finally, the paper shows the usefulness of the dispersion of FAF as a proxy for risk. Such a measure is a direct expectational measure of risk and does not rely on assumptions of risk stability over time as do most operational methods of deriving risk surrogates.

III. Models and Data

A. Model for Estimation

The DCF model states that the current market price is the present value of expected future cash flows from ownership. The simplest and most commonly used version estimates shareholders' required rate of return, k, as the sum of dividend yield and expected growth in dividends, or

$$k = (D_1/P_0) + g, \qquad (2)$$

where D_1 = dividend per share expected to be received at time one, P_0 = current price per share (time 0), and g = expected growth rate in dividends per share. The limitations of this model are well known, and it is straightforward to derive expressions for k based on more general specifications of the DCF model.[6] The primary difficulty in using the DCF model is obtaining an estimate of g, since it should reflect market expecta-

[5]In response to the FCC's *Notice of Proposed Rulemaking* [6] to determine authorized rates of return, AT&T used an approach driven by FAF growth estimates from IBES. Also see, for example, W.T. Carleton, *Testimony before the Vermont Public Service Board*, Docket No. 4865 (January 1984) and R.S. Harris, *Testimony filed with the Delaware Public Service Commission*, Docket 84–33 (November 1984). In its *Supplemental Notice* [6], the FCC tentatively endorsed substantial reliance on FAF for use in DCF determination of cost of equity.

[6]As stated, Equation (2) requires expectations of either an infinite horizon of dividend growth at rate g or a finite horizon of dividend growth at rate g and special assumptions about the price of the stock at the end of that horizon. Essentially, the assumption must ensure that the stock price grows at a compound rate of g over the finite horizon.

tions of future performance. Without a ready source for measuring such expectations, application of the DCF model is fraught with difficulties even if the simple version shown in Equation (2) fits the equity investment in question. This paper uses published FAF of long-run growth in earnings as a proxy for g.

B. Data

Many analysts publish forecasts of corporate earnings. Such forecasts are widely disseminated and are the subject of considerable interest both to investors and researchers (see Givoly and Lakonishok [8]). In recent years, this interest has led to a viable market for services that collect and disseminate such FAF. FAF for this research come from IBES (Institutional Broker's Estimate System), which is a product of Lynch, Jones, and Ryan, a major brokerage firm. Data in IBES represent a compilation of earnings per share (EPS) estimates of about 2000 individual analysts from 100 brokerage firms on over 2000 corporations. IBES data are provided to clients in a number of forms, including on-line data bases provided by vendors. The client base, which currently numbers more than 300, includes most large institutional investors such as pension funds, banks, and insurance companies. Representative of industry practice, IBES contains estimates of (i) EPS for the upcoming fiscal year, (ii) EPS for the subsequent year, and (iii) a projected five-year growth rate in EPS. Each item is available at monthly intervals.

IBES collection procedures are designed to obtain timely forecasts made on a consistent basis. IBES requests "normalized" five-year growth rates from analysts. Such normalization is designed to remove short-term distortions that might stem from using an unusually high or low earnings year as a base. These growth and other earnings forecasts are updated when analysts formally change their stated predictions. IBES does, however, verify prior forecasts monthly to make sure that analysts still hold to them. Despite these procedures, there remain potential difficulties in using IBES data to the extent that some analysts fail to normalize growth projections or fail to continually review and revise their earnings estimates. To control for some of these potential difficulties, this analysis uses averages of analysts' forecasts for a wide range of companies over an extended number of months.

In this research, the mean value of individual analyst's forecasts of five-year growth rate in EPS will be used as a proxy for g in the DCF model.[7] The five-year horizon is the longest horizon over which such forecasts are available from IBES and often is the longest horizon used by analysts. One could make alternate assumptions about growth after five years and use a more general version of a DCF model, but unfortunately, there is no source for obtaining market estimates of this expected growth. As a result, the current analysis applies the five-year growth rate as a proxy for g in Equation (2). Given no objective basis for predicting a change in growth (see Footnote 6), this avoids the introduction of *ad hoc* assumptions about future growth. Importantly, however, the approach is applied to portfolios of stocks rather than to individual securities, since future growth patterns may be expected to have drastic changes for some specific securities. Stock prices were obtained from Chase Econometrics and dividend and other firm-specific information from COMPUSTAT. Interest rates (both government and corporate) were gathered from Federal Reserve Bulletins and from Moody's Bond Record. Exhibit 1 describes key variables used in the study. Data collected cover all dividend paying stocks in the Standard and Poor's 500 stock (SP500) index plus approximately

Exhibit 1. Variable Definitions

k	=	equity required rate of return
P_0	=	average daily price per share*
D_1	=	expected dividend per share measured as current indicated annual dividend from COMPUSTAT multiplied by $(1+g)$†
g	=	average financial analysts' forecasts of five-year growth rate in earnings per share (from IBES)
σ_g	=	cross-sectional standard deviation of analysts' forecasts of growth in earnings per share (from IBES)
N_g	=	number of analysts' forecasts of g (from IBES)
i_{20}	=	yield to maturity on 20-year U.S. government obligations. Source: Federal Reserve Bulletin, constant maturity series
i_c	=	yield to maturity on long-term corporate bonds: Moody's average
i_u	=	yield to maturity on long-term public utility bonds: Moody's average
rp	=	equity risk premium calculated as $rp = k - i_{20}$

*In results reported P_0 is the average daily price for a stock from the beginning of the month up to and including the date of publication of monthly IBES data (typically half a month). Almost identical results were found using the average price for the entire month.
†See Footnote 8 at the end of the paper for a discussion of the $(1+g)$ adjustment.

[7]While the model calls for expected growth in dividends, no source of data on such projections is readily available. In addition, in the long run, dividend growth is sustainable only via growth in earnings. As long as payout ratios are not expected to change, the two growth rates will be the same. Vander Weide and Carleton [17] also use the IBES growth rate in earnings per share.

150 additional stocks of regulated companies. Since five-year growth rates were first available from IBES in January 1982, the analysis covers the 36-month period 1982–1984. On average, each company in SP500 had approximately nine individual forecasts of g per month, with some companies having 20 or more forecasts of g. As a result, well over 100,000 FAF (company-months) were employed in the analysis.

IV. Construction of Risk Premia and Required Rates of Return

For each month, a "market" required rate of return was calculated using each dividend paying stock in the SP500 index for which data were available. The DCF model in Equation (2) was applied to each stock and the results weighted by market value of equity to produce the market required return.[8] The return was converted to a risk premium by subtracting i_{20}, the yield to maturity on 20-year U.S. government bonds.[9] The procedure was repeated for the Standard and Poor's Utility Index (SPUT) of 40 stocks. Exhibit 2 reports the results by quarter.

Exhibit 2. Required Rates of Return and Risk Premia

		SP500		SPUT	
	Bond Yield*	Required† Return	Risk‡ Premium	Required† Return	Risk‡ Premium
1982					
Quarter 1	14.27	20.81	6.54	18.83	4.56
Quarter 2	13.74	20.68	6.94	18.51	4.77
Quarter 3	12.94	20.23	7.29	18.55	5.61
Quarter 4	10.72	18.58	7.86	17.20	6.48
Average	12.92	20.08	7.16	18.28	5.36
1983					
Quarter 1	10.87	18.07	7.20	16.71	5.84
Quarter 2	10.80	17.76	6.96	16.52	5.72
Quarter 3	11.79	17.90	6.11	16.39	4.60
Quarter 4	11.90	17.81	5.91	16.00	4.10
Average	11.34	17.88	6.54	16.41	5.07
1984					
Quarter 1	12.09	17.22	5.13	16.48	4.39
Quarter 2	13.21	17.42	4.21	16.99	3.78
Quarter 3	12.83	17.34	4.51	16.62	3.79
Quarter 4	11.78	17.05	5.27	15.18	4.04
Average	12.48	17.26	4.78	16.48	4.00
Average 1982–1984	12.25	18.41	6.16	17.06	4.81

*i_{20} = Yield on U.S. Treasury obligation, 20 year constant maturity.
†Monthly required return (k) calculated as value weighted average. Quarterly values are simple averages of monthly figures.
‡Risk premium calculated as $k - i_{20}$.

The results appear quite plausible. The estimated risk premia are positive, consistent with equity owners demanding a risk premium over and above returns available on debt securities. Also, as would be expected for less risky stocks, the utility risk premia consistently fall below those estimated for stocks in general. Exhibit 2 shows that estimated risk premia change over time, suggesting changes in the market's perception of the incremental risk of investing in equity rather than debt securities. Such changes will be examined in a subsequent section.

For comparative purposes, Exhibit 3 provides results of related studies. The long-run differential return between stocks and long-term government bonds (Panel A) has been about 6.4% per year (on a geometric basis). It is comforting to note that this is very close to the 6.16% average annual risk premia estimated in Exhibit 2. Note, however, that such risk premia appear to change over time. Panels B and C show some of Brigham *et al.*'s risk premium estimates. Unfortunate-

[8]The construction of D_1 is controversial since dividends are paid quarterly and may be expected to change during the year; whereas, Equation (2), as is typical, is being applied to annual data. Both the quarterly payment of dividends (due to investors' reinvestment income before year's end, see Linke, and Zumwalt [11]) and any growth during the year require an upward adjustment of the current annual rate of dividends to construct D_1. If quarterly dividends grew at a constant rate, both factors could be accommodated straightforwardly by applying Equation (2) to quarterly data (with a quarterly growth rate) and then annualizing the estimated quarterly required return. Unfortunately, with lumpy changes in dividends, the precise nature of the adjustment depends, on both an individual company's pattern of growth during the calendar year and an individual company's required return (and hence reinvestment income in that risk class).

In this work, D_1 is calculated as $D_0(1 + g)$. The full g adjustment is a crude approximation to adjust for both growth and reinvestment income. For example, if one expected dividends to have been raised, on average, six months ago, a "½ g" adjustment would allow for growth, the remaining "½ g" would be justified on the basis of reinvestment income. Any precise accounting for both reinvestment income and growth would require tracking each company's dividend change history and making explicit judgments about the quarter of the next change. Since no organized "market" forecasts of such a detailed nature exist, such a procedure is not possible. To get a feel for the magnitudes involved, the average dividend yield (D_1/P_0) and growth (market value weighted 1982–1984) for the SP500 were 5.8% and 12.5%. Comparable figures for the SP utility index were 10.4% and 6.7%. As a result, a "full g" adjustment on average increases the required return by 60–70 basis points (relative to no g adjustment) for both indices.

[9]Brigham, Shome, and Vinson [2] also use this interest rate to create equity risk premia. The results were robust to changes in weighting. For the SP500, equal weighting (rather than value weighting) increased the 1982–1984 risk premium by two basis points while for the SPUT equal weighting resulted in a 21 basis point increase. As a further test, the SP500 stocks were ranked on g and the upper and lower deciles deleted. The resulting risk premium (1982–84 average) was 5.94%. A similar procedure used to rank dividend yield produced an SP500 risk premium of 6.18%.

Exhibit 3. Results of Related Studies: Historical Returns and Estimated Risk Premia

	Geometric	Arithmetic
A. Historical Return Realizations (1926–1980)*		
Common Stocks	9.4%	11.7%
Long-Term Government Bonds	3.0%	3.1%
U.S. Treasury Bills	2.8%	2.8%

	Dow Jones Industrials		Dow Jones Electrics	
	Average	Range	Average	Range
B. DCF risk premia using one analyst†				
1966–1970	5.45	4.97–6.81	3.91	3.46–4.13
1971–1975	5.51	4.95–6.92	5.95	4.52–8.72
1976–1980	6.23	5.09–6.88	5.82	5.55–6.21
1981	5.38		5.62	
1982	5.30		3.70	
1983	5.87		5.64	
1984	3.75		4.06	
Average 1982–1984	4.97		4.47	

	Electric Utilities
C. DCF risk premia using three analysts‡	
1981	3.73
1982	4.52
1983	5.17
1984 (through June)	5.01

*Ibbotson, Sinquefield, and Siegel [9].
†Analyst is Value Line. Data are annual estimates using two-stage growth DCF model. Source: Brigham, Shome, and Vinson [2].
‡Analysts are Value Line, Merrill Lynch and Salomon Brothers. Data are averages of monthly values from Brigham, Shome, and Vinson [2].

Exhibit 4. Risk Premia by Moody's Bond Ratings*

Electric Utilities: SIC's 4911 and 4931	Aaa	Aa	A	Baa
Risk Premia				
Risk Premium (Expectational g)	3.60	4.33	4.81	4.90
Risk Premium (Historical g†)	6.10	3.28	3.09	5.24
Financial Data				
Debt Ratio‡	0.46	0.48	0.50	0.51
Beta§	0.58	0.61	0.62	0.61
Variability¶				
Operating Cash Flow	0.009	0.016	0.022	0.059
Equity Cash Flow	0.006	0.013	0.019	0.024
Standard Deviation** of Analysts' Forecasts	1.00	1.26	1.33	1.79

*Moody's ratings as of January 1984 from *Moody's Bond Record*, February 1984. The number of companies by rating is Aaa (2), Aa (22), A (32), Baa (22). Risk premia are averages of monthly values, January 1982–September 1983.
†Historical Growth is past five-year earnings growth, based on 20 quarters of past data. Source: IBES.
‡Debt Ratio = Long-Term Debt ÷ Total Capital, average 1978–1982 from COMPUSTAT.
§Beta from *Value Line*, January 29, 1982.
¶Measure of variability around trend growth: variance of residuals of regressions on quarterly COMPUSTAT data (1978–1982). Regressions are log of variable regressed on time and seasonal dummies.
**This is the average value of the standard deviation around the mean long-term growth forecast. Such standard deviations are reported for each company in each month. Note it is *not* the cross-sectional standard deviation of growth rates among companies.

ly, their work does not include a broad market index directly comparable to the SP500. Rather, they use the Dow Jones Industrial Index based on 30 large industrial concerns. Though the SPUT includes a broader set of utilities than the electrics covered by Brigham *et al.*, their average risk premium estimates are also in the 4 to 5% range for the early 1980s.

While the estimates in Exhibit 2 are quite plausible, the question still remains as to whether they satisfy economic criteria one would expect of risk premia. In the following section, the estimated risk premia are subjected to a series of tests to see if they vary both cross-sectionally and over time with changes in risk. The tests are ultimately joint tests of the estimates as useful risk premia, the measured proxies for risk and the validity of the economic hypothesis. Nonetheless, if the tests using the risk premia have results conforming to theoretical expectation, the comfort level in using them is increased accordingly.

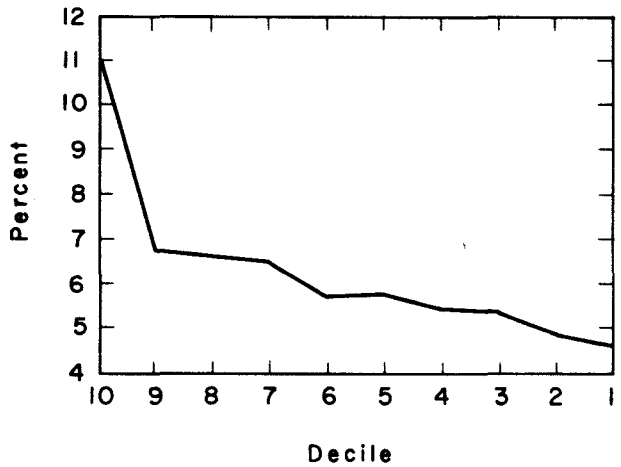
V. Characteristics of Risk Premia

A. Cross-Sectional Tests

Brigham *et al.* show that risk premia (IBES estimates for first half of 1984) for electric utilities are lower the higher the bond rating of the company, confirming the expected tradeoff between risk and return. A similar experiment for electrics, using the current data stretching back to January 1982, confirmed this relationship for a longer time period. Exhibit 4 reports selected results of that analysis. As a contrast, Exhibit 4 also shows the results of using historical growth rates (rather than FAF) in a DCF model. Risk premia derived from historical growth are actually higher for companies with very safe debt, suggesting the clear inferiority of historical to expectational growth rates. With the exception of beta, which is roughly constant across groups, other measures of risk noted in Exhibit 4 confirm the risk differentials associated with bond rating groups.

A further test of the cross-sectional variation in risk premia was performed by dividing the universe of

Exhibit 5. Equity Risk Premia: Deciles Based on Standard Deviation of Financial Analysts Forecasts* (Companies with at least three analysts)



*Risk premia were calculated as equally weighted averages for each decile (10 = highest dispersion) for each of three months: January 1982, December 1982, and September 1983 (approximately 50 companies per decile). These premia were then averaged across deciles. A similar downward pattern was evident in each month.

stocks (industrial plus utility) according to the dispersion of analysts' forecasts, σ_g. This cross-sectional measure of analysts' disagreement should be positively related to the uncertainty of future growth prospects and hence to the riskiness of equity investment. Elsewhere, Malkiel [12] has discussed the rationale and usefulness of such dispersion as an *ex ante* measure of risk. Malkiel argues that σ_g may be a proxy for systematic risk and shows that it bears a closer empirical relationship to expected return than does beta or other risk measures. Most of Malkiel's work is, however, based on data from the 1960s. Exhibit 5 reports risk premia by decile based on σ_g for companies having at least three analysts' forecasts. The three months were chosen as representative. The results show a consistent positive relationship between risk premia and dispersion of analysts' forecasts.

The results in Exhibits 4 and 5 show that the estimated risk premia conform to theoretical relationships between risk and required return that are expected when investors are risk averse. This strengthens the case for using such risk premia, and provides encouragement for further study of their structure.[10]

[10]Such *ex ante* required returns offer a useful alternative to *ex post* data typically used in tests of asset pricing models. See Friend, Westerfield, and Granito [7] for a test of the CAPM using survey data rather than *ex post* holding period returns.

B. Time Series Tests

A potential benefit of using *ex ante* risk premia is the estimation of changes in risk premia over time. Brigham *et al.* [2] note such changes for utility stocks and relate them to changes in interest rates. They conclude that prior to 1980 utility risk premia increased with the level of interest rates, but that this pattern reversed thereafter, resulting in an inverse correlation between risk premia and interest rates. They explain this turnaround as the outcome of changes in bond markets and adaptation of utilities and their regulators to an inflationary environment. Brigham *et al.* do not, however, analyze changing risk premia for stocks in general. Furthermore, they do not provide direct empirical proxies for changes in equity risks that would explain changes in equity risk premia over time.[11]

C. Changes in Risk Premia

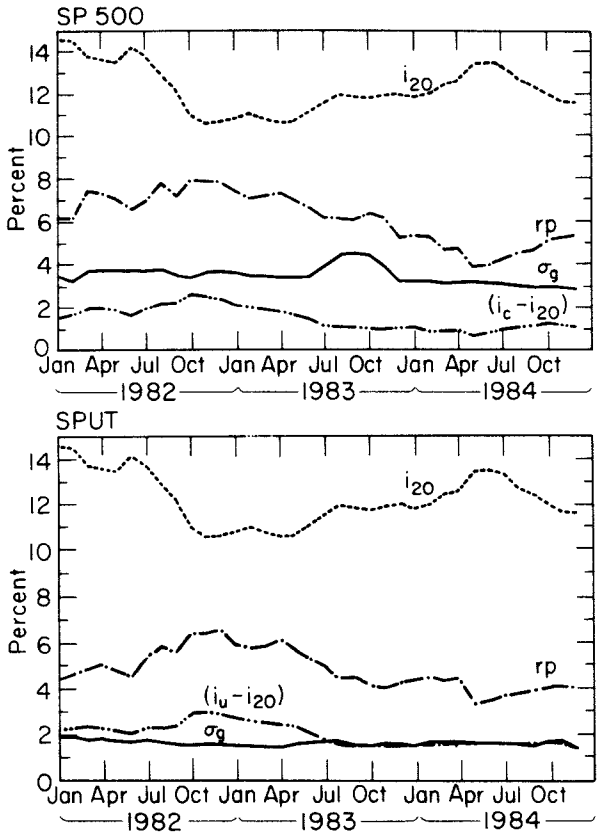
One would expect changes in measured equity risk premia to be related to changes in perceived riskiness. First, with changes in the economy and financial markets, equity investments may be perceived to change in risk. Second, since government bonds are risky investments themselves, their perceived riskiness may change. For example, the large increase in interest rate volatility in the last decade has undoubtedly made fixed income investments more risky holdings than they were in a world of relatively stable rates. Measured equity risk premia (relative to government bonds) could thus be reduced due to increases in perceived riskiness of bonds, even if equities displayed no shifts in risk.

One measure of risk, the standard deviation of FAF, σ_g, was shown previously to be related to cross-sectional differences in risk premia. To test its usefulness as a time series measure of risk, the average value of σ_g was calculated each month for the SP500 index and the SPUT index. The results are graphed in Exhibit 6.[12]

[11]In addition, Brigham *et al.* do not report on their treatment of serial correlation in reported regression results, making it more difficult to interpret their findings. As an example, monthly data are used for the 1980–1984 period in a time series regression of a risk premium on the level of interest rates. Similar regressions using data in this paper (1982–1984 monthly data) showed significant positive autocorrelation with Durbin Watson Statistics well below 1.0.

[12]The average values of σ_g are the market value weighted averages of the σ_g for individual stocks. If one looked at a direct estimate of g made by individual analysts for the index, one would expect to find a lower amount of dispersion because some of the differences on individual securities would cancel out. Such data are not available. One would suspect, however, that the calculated average would move up and down in tandem with this unobservable measure of dispersion.

Exhibit 6. Equity Risk Premia, Interest Rates and Risk



Another possible time series proxy for equity risk is the set of yield spreads between corporate and government bonds. As the perceived riskiness of corporate activity increases, the difference between yields on corporate bonds and government bonds should increase. One would expect the sources of increased riskiness to corporate bonds to also increase risks to shareholders.[13] Exhibit 6 graphs two series of yield spreads. The first is the difference between the yield on Moody's corporate average series and the yield on 20-year U.S. Treasury obligations. This series includes debt of both industrial and utility companies and thus would be appropriate as a risk proxy for a broad market index such as the SP500. The second is the spread between the yields on Moody's public utility series and 20-year U.S. Treasury bonds. This series should reflect relative risks of utility stocks as proxied by SPUT.[14]

Exhibit 7 reports results of analyzing the relationship between risk premia, interest rates, and proxies for risk for both the SP500 and SPUT. All regressions are corrected for serial correlation.[15] For stocks in general, Panel A shows that risk premia are negatively related to the level of interest rates — as proxied by i_{20}. Such a negative relationship may result from increases in the perceived riskiness of investment in government debt at high levels of interest rates. A direct measure of uncertainty about investments in government bonds would be necessary to test this hypothesis directly.

The results also show the significant positive relationship between the two proxies for risk and the estimated risk premia. For example, regression 4 of Panel A shows that the equity premium on the SP500 increases with the dispersion of FAF (σ_g) and the yield spread between corporate and government bonds ($i_c - i_{20}$). Evidently, these two risk measures capture somewhat different dimensions of risk, both of which appear important in explaining risk premia on stocks in general. The simple correlation coefficient between the two risk measures is 0.19 and is insignificantly different from zero. The addition of the yield spread risk proxy also dramatically lowers the magnitude of the coefficient on government bond yields, as can be seen by comparing Equations 1 and 3 of Panel A. Apparently, a large part of the effect of changes in government bond rates on equity risk premia may be explained through the narrowing of the yield spread between corporate and government bonds. This suggests that such increases in government yields may often be associated with a reduction in the *difference* in risk between investment in government bonds and in corporate activity.

Panel B shows that utility risk premia are also inversely related to the level of interest rates as was found by Brigham *et al.* [2]. Unlike the results for stocks in general, however, changes in the dispersion of FAF over time are not significantly related to changes in these utility risk premia. This may be be-

[13]Of course, counterexamples could be constructed but one would expect an overall positive correlation across companies. Additionally, the cross-sectional relationship between bond ratings and equity risk premia reported earlier in the paper supports the link between corporate debt risks and risks on equity.

[14]Note that these two series reflect both changes in the ratings of corporate bonds as well as yield spreads for a given bond rating. The two series proved better in explaining equity risk premia than use of two comparable series for AA-rated debt.

[15]Ordinary least squares regressions showed severe positive autocorrelation in many cases with Durbin Watson Statistics typically below one. Estimation used the Prais-Winsten method. See Johnston [10], pp. 321–325.

Exhibit 7. Changes in Equity Risk Premia Over Time — Entries are Coefficient (t-value)

Regression	Intercept	i_{20}	σ_g	$i_c - i_{20}$	R^2
A. SP500: Dependent Variable is Equity Risk Premium*					
1.	0.140	−0.632			0.43
	(8.15)†	(−4.95)†			
2.	0.118	−0.660	0.754		0.58
	(7.10)†	(−5.93)†	(3.32)†		
3.	0.069	−0.235		1.448	0.57
	(3.44)†	(−1.76)		(4.18)†	
4.	0.030	−0.177	0.855	1.645	0.79
	(2.17)†	(−2.07)†	(4.68)†	(7.63)†	
Regression	Intercept	i_{20}	σ_g	$i_u - i_{20}$	R^2
B. SPUT: Dependent Variable is Equity Risk Premium*					
1.	0.110	−0.510			0.37
	(7.35)†	(−4.41)†			
2.	0.101	−0.543	0.805		0.41
	(6.28)†	(−4.68)†	(1.42)		
3.	0.051	−0.259		1.432	0.80
	(5.54)†	(−4.05)†		(8.87)†	
4.	0.049	−0.287	0.387	1.391	0.80
	(5.15)†	(−3.87)†	(0.75)	(8.14)†	

*All variables are defined in Exhibit 1 and graphed in Exhibit 6. Regressions were estimated for the 36 month period January 1982–December 1984 and were corrected for serial correlation using the Prais-Winsten method. For purposes of this regression variables are expressed in decimal form, *e.g.*, 14% = 0.14.

†Significantly different from zero at 0.05 level using two-tailed test.

cause of lower variability over time in the dispersion of FAF for utility stocks as compared to equities in general. The yield spread between utility and government bonds is significantly positively related to utility equity risk premia. And, as in the case of stocks in general, introduction of this spread substantially reduces the independent effect of interest rate levels on equity risk premia.

Given the short time series (36 months), tests for the stability of the relationships found in Exhibit 7 present difficulties. As a check, the relationships were reestimated dividing the data into two 18-month periods. For stocks in general (SP500), coefficients on σ_g and $(i_c - i_{20})$ were positive in all regressions and significantly so, except in the case of $(i_c - i_{20})$ for the second 18-month period. The coefficient of i_{20} was significantly negative in both periods. This confirms the general findings for the SP500 in Panel A of Exhibit 7. For utility stocks, results for the subperiods also matched the entire period results. The coefficients of $(i_u - i_{20})$ were significantly positive in both subperiods while those of σ_g were insignificantly different from zero. The level of interest rates (i_{20}) had a significant negative effect in both subperiods.

In summary, the estimated risk premia change over time and the patterns of such change are directly related to changes in proxies for the risks of equity investments. Risk premia for both stocks in general and utilities are inversely related to the level of government interest rates but positively related to the bond yield spreads which proxy for the incremental risk of investing in equities rather than government bonds. For stocks in general, risk premia also increase over time with increases in the general level of disagreement about future corporate performance.

VI. Conclusions

Notions of shareholder required rates of return and risk premia are based in theory on investors' expectations about the future. Research has demonstrated the usefulness of financial analysts' forecasts for such expectations. When such forecasts are used to derive equity risk premia, the results are quite encouraging. In addition to meeting the theoretical requirement of using expectational data, the procedure produces estimates of reasonable magnitude that behave as econom-

ic theory would predict. Both over time and across stocks, the risk premia vary directly with the perceived riskiness of equity investment.

The approach offers a straightforward and powerful aid in establishing required rates of return either for corporate investment decisions or in the regulatory arena. Since data are readily available on a wide range of equities, an investigator can analyze various proxy groups (*e.g.*, portfolios of utility stocks) appropriate for a particular decision. An additional advantage of the estimated risk premia is that they allow analysis of changes in equity return requirements over time. Tracking such changes is important for managers facing changing economic climates.

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To illustrate the two-stage growth model, we can alter the growth assumptions of the example found under the single-stage model. Assume that the analysts' growth rate of 8 percent applies only to years one through five. For years six and onwards, assume a growth rate of 5 percent.

Year	Growth Rate (%)	Annual Dividend ($)	Present Value Factor @ 9.78 %	Present Value of Dividend ($)
0		2.00	1.00	
1	8.0	2.16	0.91	1.97
2	8.0	2.33	0.83	1.94
3	8.0	2.52	0.76	1.90
4	8.0	2.72	0.69	1.87
5	8.0	2.94	0.63	1.84
6–forever	5.0	3.09	13.12	40.48
			Total	$50.00

We arrive at the current stock price of $50 by discounting this stream of cash flows at an estimated rate of 9.78 percent. This is a considerably different estimate compared to the 12.32 percent we arrive at using a constant growth rate of 8 percent. Therefore, the growth rate assumptions can have a significant impact on the cost of equity estimate.

Year	Growth Rate (%)	Annual Dividend ($)	Present Value Factor @ 10.03%	Present Value of Dividend ($)
0		2.00	1.00	
1	8.0	2.16	0.91	1.96
2	8.0	2.33	0.83	1.93
3	8.0	2.52	0.75	1.89
4	8.0	2.72	0.68	1.86
5	8.0	2.94	0.62	1.82
6	6.5	3.13	0.56	1.76
7	6.5	3.33	0.51	1.71
8	6.5	3.55	0.47	1.65
9	6.5	3.78	0.42	1.60
10	6.5	4.03	0.38	1.55
11–forever	5.0	4.23	7.63	32.27
			Total	$50.00

The Three-Stage Growth Model

Additional growth stages can be used but, in practice, only one-, two-, or three-stage discounted cash flow models are usually employed. The three-stage model is denoted as follows:

$$PV_s = \sum_{i=1}^{n1} \frac{CF_0(1+g_1)^i}{(1+k_s)^i} + \sum_{i=n1+1}^{n2} \frac{CF_{n1}(1+g_2)^{i-n1}}{(1+k_s)^i} + \frac{\frac{CF_{n2}(1+g_3)}{(k_s-g_3)}}{(1+k_s)^{n2}}$$

where:

- k_s = the cost of equity for company **s**;
- PV_s = the current market value of company **s**;
- i = a measure of time (in this example the unit of measure is a year);
- n_1 = the number of years in the first stage of growth;
- n_2 = the last year in the second stage of growth;
- CF_0 = the dividend or cash flow amount (in $) in year 0;
- CF_{n1} = the expected dividend or cash flow amount (in $) in year $\mathbf{n}_1$;
- CF_{n2} = the expected dividend or cash flow amount (in $) in year $\mathbf{n}_2$;
- g_1 = the expected dividend or cash flow growth rate from year 1 to year $\mathbf{n}_1$;
- g_2 = the expected dividend or cash flow growth rate from year (n_1+1) to year $\mathbf{n}_2$; and
- g_3 = the expected perpetual dividend or cash flow growth rate starting in year (n_2+1).

To illustrate the three-stage growth model, we alter the growth assumptions of the two-stage model example (see table on left). Again we assume that the analysts' growth rate of eight percent applies only to years one through five. For years 6 through 10, we assume a growth rate of 6.5 percent. In the last stage, from year 11 and beyond, we assume a perpetual growth rate of 5 percent.

By discounting this stream of cash flows at a rate of 10.03 percent, we arrive at the current stock price of $50.

Timing Differences and Discount Rates

Year	Growth Rate (%)	Annual Dividend ($)	Periodic Dividend ($)	Reinvestment ($)	Total Dividend ($)	Present Value Factor @ 9.96%	Present Value of Dividend ($)
0		2.00				1.00	
1	8.0	2.16	0.54	0.08	2.24	0.91	2.04
2	8.0	2.33	0.58	0.09	2.42	0.83	2.00
3	8.0	2.52	0.63	0.10	2.62	0.75	1.97
4	8.0	2.72	0.68	0.10	2.82	0.68	1.93
5	8.0	2.94	0.73	0.11	3.05	0.62	1.90
6–forever	5.0	3.09	0.77	0.12	3.20	12.54	40.16
						Total	$50.00

Quarterly Dividend Adjustment

When valuing a stock, one should remember that even though dividends grow and are declared annually, they are usually paid in equal quarterly installments. In order to account for this in the discounted cash flow model, each cash flow can be replaced by the following term:

$$CF_i \times \frac{1+(1+k)^{1/4}+(1+k)^{1/2}+(1+k)^{3/4}}{4}$$

If we look at the same example that was used for the two-stage discounted cash flow model but use the quarterly dividend adjustment, the cost of equity estimate becomes 9.96 percent instead of 9.78 percent. The higher discount rate reflects the difference in timing of the cash flows, as shown below.

Estimating Growth Rates

One of the advantages of a three-stage discounted cash flow model is that it fits with life cycle theories in regards to company growth. In these theories, companies are assumed to have a life cycle with varying growth characteristics. Typically, the potential for extraordinary growth in the near term eases over time and eventually growth slows to a more stable level.

In the *Ibbotson Cost of Capital Yearbook* the three-stage growth model is used. In the first stage (the first five years), analysts' consensus estimates of earnings growth are used. These should reflect any extraordinary near-term growth potential. Over years 6 through 10, an average of the analysts' consensus estimates of growth for the entire industry is used (we assume that over a middle horizon, growth of any particular company will lie more in line with the industry as a whole). Finally, in years 11 and beyond, a growth rate estimate for the entire economy is used, reflecting the belief that even in a rapidly growing industry there will come a time when growth slows to be more in line with the overall economy.

Short-term growth rates are generally available from security analysts who follow a particular company or industry. Long-term growth rates can be estimated in a number of ways. One rudimentary estimate of long-term growth is the sustainable-growth model. This model relies on two accounting concepts: return on equity and the plow-back ratio.

Sustainable growth is then given by:

$$g_s = b_s \times ROE_s$$

where:

g_s = the sustainable growth rate for company **s**;

b_s = the plow-back ratio of company **s** calculated as follows:

$$\frac{\text{Annual Earnings} - \text{Annual Dividends}}{\text{Annual Earnings}}\text{; and}$$

ROE_s = the return on book equity of company **s** calculated as follows:

$$\frac{\text{Annual Earnings}}{\text{Book Value of Equity}}$$

This model relies on a number of assumptions that may or may not hold. The first of these assumptions is that ROE and the plow-back of earnings are constant over time. That is, there exists a forecast of these two accounting ratios that is sustainable in the long term. Though the model appears simple to implement at first glance, finding a forecast of the ratios that is sustainable indefinitely is extremely difficult. Dividend policy and potential investment opportunities change over time and have a direct impact on these ratios.

The model assumes that the only possible source of corporate earnings growth is the reinvestment of earnings into the existing business and that any investment of funds in the firm will earn the same rate of return as existing projects. However, firms generally seek projects that have a higher return than existing projects. The sustainable growth model may therefore underestimate a firm's future growth. Other problems may arise because the model relies on accounting practices that can distort earnings.

In addition, other sources of growth may exist that do not require the plow-back of earnings. Changes in technology can advance growth with little capital expenditure by a firm. For instance, efficiency in the transfer of information has improved tremendously over the years as a result of internet technology. Many companies benefit from this increased efficiency with little direct investment in the internet. A company may also grow at the rate of inflation without retaining any earnings. The growth rate that the model estimates is a nominal growth rate, not a real growth rate. If retained earnings are zero, the model predicts zero growth; however, a firm could still grow at the general rate of inflation.

Another approach to estimating long-term growth rates is to focus on estimating the overall economic growth rate. Again, this is the approach used in the *Ibbotson Cost of Capital Yearbook*. To obtain the economic growth rate, a forecast is made of the growth rate's component parts. Expected growth can be broken into two main parts: expected inflation and expected real growth. By analyzing these components separately, it is easier to see the factors that drive growth.

Treasury Inflation-Protected Securities (TIPS), a relatively new investment vehicle in the U.S., can be used in conjunction with traditional long-term government bonds to estimate the market expectation for inflation. Theoretically, the yield on inflation-indexed bonds is equal to the real default-free rate of return.

To estimate long-term inflation, we can start with the current yield on a government bond with approximately 20 years to maturity of 2.41 percent and subtract the current yield on an inflation-indexed bond with approximately 20 years to maturity of 0.15 percent, for an inflation estimate of 2.26 percent.

Once the long-term expected inflation rate is estimated, the real growth rate must be determined. The growth rate in real Gross Domestic Product (GDP) for the period 1929 to 2012 was approximately 3.22 percent. Growth in real GDP (with only a few exceptions) has been reasonably stable over time; therefore, its historical performance is a good estimate of expected long-term (future) performance.

By combining the inflation estimate with the real growth rate estimate, a long-term estimate of nominal growth is formed:

2.26 percent + 3.22 percent = 5.48 percent.

Endnotes

[1] This relationship does not seem to hold empirically with small company stocks. This size effect is discussed in Chapter 7.

[2] In general, small company betas are expected to be higher than large company betas. This, however, does not hold for all time periods. Chapter 6 discusses in more detail the measurement of beta for small stocks.

[3] The beta-adjusted size premia are different from the small stock premia (or non-beta-adjusted size premia) shown in previous editions of the *Ibbotson Stocks, Bonds, Bills, and Inflation Yearbook* (prior to the 1995 Yearbook). The small stock premium reported in older editions of Stocks, Bonds, Bills, and Inflation is the difference in long-term average returns between the large company stock total return series (currently represented by the S&P 500) and the small company stock total return series (currently represented by the Dimensional Fund Advisors U.S. Micro Cap Portfolio). The size premia given here are based on slightly different baskets of stocks from the CRSP (Center for Research in Security Prices) data set and, more importantly, they are adjusted for beta. That is, small stocks do have higher betas than large stocks; the return, above what might be expected because of the higher betas, is the size premium. These size premia increase as the capitalization of the company decreases. Chapter 7 describes the development of these premia in more detail.

[4] Beta estimate is based on the full information beta for SIC code 36 from the *Ibbotson Industry Cost of Capital Reports* as of December 31, 2012 and December 31, 1996. This beta estimation methodology is described in detail in Chapter 6. For more information, visit http://global.morningstar.com/IndReportsStats

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Do Analyst Conflicts Matter? Evidence from Stock Recommendations

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Abstract

We examine whether conflicts of interest with investment banking and brokerage businesses induce sell-side analysts to issue optimistic stock recommendations and, if so, whether investors are misled by such biases. Using quantitative measures of potential conflicts constructed from a novel data set containing revenue breakdowns of analyst employers, we find that recommendation levels are indeed positively related to conflict magnitudes. The optimistic bias stemming from investment banking conflicts was especially pronounced during the late-1990s stock market bubble. However, evidence from the response of stock prices and trading volumes to upgrades and downgrades suggests that the market recognizes analysts' conflicts and properly discounts analysts' opinions. This pattern persists even during the bubble period. Moreover, the 1-year stock performance following revised recommendations is unrelated to the magnitude of conflicts. Overall, our findings do not support the view that conflicted analysts are able to systematically mislead investors with optimistic stock recommendations.

1. Introduction

In April 2003, 10 of the largest Wall Street firms reached a landmark settlement with state and federal securities regulators on the issue of conflicts of interest

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faced by stock analysts.[1] The settlement requires the firms to pay a record $1.4 billion in compensation and penalties in response to government charges that the firms issued optimistic stock research to win favor with potential investment banking (IB) clients. Part of the settlement funds are earmarked for investor education and for provision of research from independent firms. In addition to requiring large monetary payments, the settlement mandates structural changes in the firms' research operations and requires the firms to disclose conflicts of interest in analysts' research reports.

The notion that investors are victims of biased stock research presumes that (1) analysts respond to the conflicts by inflating their stock recommendations and (2) investors take analysts' recommendations at face value. Even if analysts are biased, it is possible that investors understand the conflicts of interest inherent in stock research and rationally discount analysts' opinions. This alternative viewpoint, if accurate, would lead to very different conclusions about the consequences of analysts' research. Indeed, investors' rationality and self-interested behavior imply that stock prices should accurately reflect a consensus about the informational quality of public announcements (Grossman 1976; Grossman and Stiglitz 1980). Rational investors would recognize and adjust for analysts' potential conflicts of interest and thereby largely avoid the adverse consequences of biased stock recommendations.

In this article, we provide evidence on the extent to which analysts and investors respond to conflicts of interest in stock research. We address four questions. First, is the extent of optimism in stock recommendations related to the magnitudes of analysts' conflicts of interest? Second, to what extent do investors discount the opinions of more conflicted analysts? In particular, do stock prices and trading volumes react to recommendation revisions in a manner that rationally reflects the degree of analysts' conflicts? Third, is the medium-term (that is, 3- to 12-month) performance of recommendation revisions related to conflict severity? And, finally, did conflicts of interest affect analysts or investors differently during the late-1990s stock bubble than during the postbubble period? The answers to these questions are clearly of relevance to stock market participants, public policy makers, regulators, and the academic profession.

We use a unique, hand-collected data set that contains the annual revenue breakdown for 232 public and private analyst employers. This information allows us to construct quantitative measures of the magnitude of potential conflicts not only from IB business but also from brokerage business. We analyze a sample of over 110,000 stock recommendations issued by over 4,000 analysts during the 1994–2003 time period. Using univariate tests as well as cross-sectional regressions that control for the size of the company followed and individual analysts' experience, resources, workloads, and reputations, we attempt to shed

[1] Two more securities firms (Deutsche Bank Securities Inc. and Thomas Weisel Partners LLC) were added to the formal settlement in August 2004.

light both on how analysts respond to pressures from IB and brokerage businesses and on how investors compensate for the existence of such conflicts of interest.

A number of studies (for example, Dugar and Nathan 1995; Lin and McNichols 1998; Michaely and Womack 1999; Dechow, Hutton, and Sloan 2000; Bradley, Jordan, and Ritter 2008) focus on conflicts faced by analysts in the context of existing underwriting relationships (see also Malmendier and Shanthikumar 2007; Cliff 2007).[2] Our article complements this literature in several ways. First, we take into account the pressure to generate underwriting business from both current and potential client companies. Even if an analyst's firm does not currently do IB business with a company that the analyst tracks, it might like to do so in the future. Second, we examine the conflict between research and all IB services (including advice on mergers, restructuring, and corporate control), rather than just underwriting. Third, we examine conflicts arising from brokerage business in addition to those from IB.[3]

Fourth, the prior empirical finding that underwriter analysts tend to be more optimistic than other analysts is consistent with two alternative interpretations: (*a*) an optimistic report on a company by an underwriter analyst is a reward for past IB business or an attempt to win future IB business by currying favor with the company or (*b*) a company chooses an underwriter whose analyst already likes the stock. The second interpretation implies that underwriter choice is endogenous and does not necessarily imply a conflict of interest. We sidestep this issue of endogeneity by not focusing on underwriting relations between an analyst's firm and the company followed. Instead, our conflict measures focus on the importance to the analyst's firm of IB and brokerage businesses, as measured by the percentage of its annual revenue derived from IB business and from brokerage commissions. Unlike underwriting relations between an analyst's firm and the company followed, the proportions of the entire firm's revenues from each of these businesses can reasonably be viewed as given, exogenous variables from the viewpoint of an individual analyst. Finally, our approach yields substantially larger sample sizes than those used in prior research, and it therefore leads to greater statistical reliability of the results.

Several articles adopt an approach that is similar in spirit to ours. For example, Barber, Lehavy, and Trueman (2007) find that recommendation upgrades (downgrades) by investment banks—which typically also have brokerage businesses—

[2] Bolton, Freixas, and Shapiro (2007) theoretically analyze a different type of conflict of interest in financial intermediation, one faced by a financial advisor whose firm also produces financial products (such as in-house mutual funds). Mehran and Stulz (2007) provide an excellent review of the literature on conflicts of interest in financial institutions.

[3] Hayes (1998) analyzes how pressure on analysts to generate brokerage commissions affects the availability and accuracy of earnings forecasts. Both Irvine (2004) and Jackson (2005) find that analysts' optimism increases a brokerage firm's share of the trading volume. Ljungqvist et al. (2007) find that analysts employed by larger brokerage houses issue more optimistic recommendations and more accurate earnings forecasts. However, none of these articles examines how investors' responses to analysts' recommendations and the investment performance of recommendations vary with the severity of brokerage conflicts, issues that we investigate here.

underperform (outperform) similar recommendations by non-IB brokerages and independent research firms. Cowen, Groysberg, and Healy (2006) find that full-service securities firms—which have both IB and brokerage businesses—issue less optimistic forecasts and recommendations than do non-IB brokerage houses. Finally, Jacob, Rock, and Weber (2008) find that short-term earnings forecasts made by investment banks are more accurate and less optimistic than those made by independent research firms. We extend this line of research by quantifying the reliance of a securities firm on IB and brokerage businesses. This is an important feature of our article for at least two reasons. First, given that many securities firms operate in multiple lines of business, it is difficult to classify them by business lines. By separately measuring the magnitudes of both IB and brokerage conflicts in each firm, our approach avoids the need to rely on a classification scheme. Second, since the focus of this research is on the consequences of analysts' conflicts, the measurement of those conflicts is important. Our conclusions sometimes differ from those in classification-based studies.

We find that analysts do indeed seem to respond to pressures from IB and brokerage businesses: larger potential conflicts of interest from these businesses are associated with more positive stock recommendations. We also document that the distortive effects of IB conflicts were larger during the late-1990s stock bubble than during the postbubble period. Nonetheless, the empirical analysis yields several pieces of evidence to suggest that investors are sophisticated enough to adjust for these biases. First, the short-term reactions of both stock prices and trading volumes to recommendation upgrades are negatively and statistically significantly related to the magnitudes of potential IB or brokerage conflicts. For downgrades, the corresponding relation is negative for stock prices but positive for trading volumes. Second, the 1-year investment performance after recommendation revisions bears no systematic relation to the magnitude of conflicts. Finally, investors continued to discount conflicted analysts' opinions during the bubble period, even amid the euphoria prevailing in the market at the time. Together these results strongly support the idea that the marginal investor, taking analysts' conflicts into account, rationally discounts optimistic stock recommendations.[4]

The remainder of the article is organized as follows. We discuss the issues in Section 2 and describe our sample and data in Section 3. Section 4 examines the relation between recommendation levels and the degree of IB or brokerage conflict faced by analysts. Section 5 analyzes how conflicts are related to the response of stock prices or trading volumes to recommendation revisions. Section

[4] In a companion paper (Agrawal and Chen 2005), we find that analysts appear to respond to conflicts when making long-term earnings growth projections but not short-term earnings forecasts. This finding is consistent with the idea that, with short-term forecasts, analysts worry about their deception being revealed with the next quarterly earnings release, but they have greater leeway with long-term forecasts. We also find that the frequency of forecast revisions is positively related to the magnitude of brokerage conflicts, and several tests suggest that analysts' trade generation incentives impair the quality of stock research.

6 investigates the relation between conflicts and the investment performance of recommendation revisions. Section 7 presents our results for the late-1990s stock bubble and postbubble periods, and Section 8 concludes.

2. Issues and Hypotheses

Investment banking activity is a potential source of analyst conflict that has received widespread attention in the financial media (for example, Gasparino 2002; Maremont and Bray 2004) as well as the academic literature (for example, Lin and McNichols 1998; Michaely and Womack 1999). When IB business is an important source of revenue for a securities firm, a stock analyst employed by the firm often faces pressure to inflate his or her recommendations. This pressure is due to the fact that the firm would like to sell IB services to a company that the analyst tracks.[5] The company, in turn, would like the analyst to support its stock with a favorable opinion. Thus, we expect that the more critical is IB revenue to an analyst's employer, the greater the incentives an analyst faces to issue optimistic recommendations.[6]

Analysts also face a potential conflict with their employers' brokerage businesses. Here, the pressure on analysts originates not from the companies that they follow but from within their employing firms. Brokerage business generates a large portion of most securities firms' revenues, and analyst compensation schemes are typically related explicitly or implicitly to trading commissions. Thus, analysts have incentives to increase trading volumes in both directions (that is, buys and sells). Given the many institutional constraints that make short sales relatively costly, many more investors participate in stock purchases than in stock sales.[7] Indeed, it is mostly existing shareholders of a stock who sell. This asymmetry between purchases and sales implies that the more important brokerage business is to an analyst's employer, the more pressure the analyst faces to be bullish when issuing recommendations.

Analysts who respond to the conflicts they face by issuing blatantly misleading stock recommendations can develop bad reputations that reduce their labor income and hurt their careers.[8] Stock recommendations, however, are not as easily evaluated as other outputs of analysts' research, such as 12-month price targets or quarterly earnings forecasts, which can be judged against public, near-

[5] Throughout this article, we refer to an analyst's employer as a "firm" and a company followed by an analyst as a "company."

[6] Ljungqvist, Marston, and Wilhelm (2006, forthcoming) find that, while optimistic recommendations do not help the analyst's firm win the lead underwriter or comanager positions in general, they help the firm win the comanager position in deals in which the lead underwriter is a commercial bank.

[7] Numerous regulations in the United States increase the cost of selling shares short (see, for example, Dechow et al. 2001). Therefore, the vast majority of stock sales are regular sales rather than short sales. For example, over the 1994–2001 period, short sales comprised only about 10 percent of the annual New York Stock Exchange trading volume (New York Stock Exchange 2002).

[8] See Jackson (2005) for a theoretical model showing that analysts' concerns about their reputations can reduce optimistic biases arising from brokerage business.

term realizations. So it is not clear whether analysts' career concerns can completely prevent them from responding to pressures to generate IB or brokerage business.

The relation between conflict severity and the short-term (2- or 3-day) stock price impact of a recommendation should depend on whether investors react to the opinion rationally or naively.[9] Under the rational discounting hypothesis, the relation should be asymmetric for upgrades and downgrades. For upgrades, the stock price response should be negatively related to the degree of conflict. This implication arises because analysts who face greater pressure from IB or brokerage business are likely to be more bullish in their recommendations, and rational investors should discount an analyst's optimism more heavily. For downgrades, however, the story is different. When an analyst downgrades a stock despite facing large conflicts, rational investors should find the negative opinion more convincing and should be more likely to revalue the stock accordingly. This implies that the short-term stock price response to a downgrade should be negatively related to the degree of conflict.

The rational discounting hypothesis also predicts cross-sectional relations between conflict severity and the short-term trading volume responses to recommendations. As Kim and Verrecchia (1991) demonstrate in a rational expectations model of trading, the more precise a piece of news, the more individuals will revise their prior beliefs and, hence, the more trading that will result. In the present context, investor rationality implies that an upgrade by a highly conflicted analyst represents less precise news to investors, and so such a revision should be followed by a relatively small abnormal volume. But when an analyst downgrades a stock despite a substantial conflict, the signal is regarded as being more precise, and thus the downgrade should lead to relatively large abnormal trading.

By contrast, under the naive investor hypothesis, investors are largely ignorant of the distortive pressures that analysts face and accept analysts' recommendations at face value. This implies that there should be no relation between conflict severity and the short-term response of either stock prices or trading volume to recommendation revisions. Furthermore, the absence of a systematic relation should hold true for both upgrades and downgrades.

What are the implications of the two hypotheses for the medium-term (3- to 12-month) investment performance of analysts' recommendations? Under the rational discounting hypothesis, there should be no systematic relation between the magnitude of conflicts faced by an analyst and the performance of his or her stock recommendations: the market correctly anticipates the potential distortions up front and accordingly adjusts its response. But the naive investor hypothesis predicts that performance should be negatively related to conflict

[9] This framework follows Kroszner and Rajan (1994) and Gompers and Lerner (1999), who analyze the conflicts that a bank faces in underwriting securities of a company when the bank owns a (debt or equity) stake in it.

severity for both upgrades and downgrades. That is, investors ignore analysts' conflicts up front and pay for their ignorance later.

3. Sample and Data

3.1. Sample

Our sample of stock recommendations comes from the Institutional Brokers Estimate System (I/B/E/S) U.S. Detail Recommendations History file. This file contains data on newly issued recommendations as well as revisions and reiterations of existing recommendations made by individual analysts over the period 1993–2003. Although the exact wording of recommendations can vary considerably across brokerage houses, I/B/E/S classifies all recommendations into five categories ranging from strong buy to strong sell. We rely on the I/B/E/S classification and encode recommendations on a numerical scale from 5 (strong buy) to 1 (strong sell).

Since we are primarily interested in examining how the nature and consequences of analysts' recommendations are related to IB or brokerage business, we require measures of the importance of these business lines to analysts' employers. Under U.S. law, all registered broker-dealer firms must file audited annual financial statements with the Securities and Exchange Commission (SEC) in x-17a-5 filings.[10] These filings contain information on broker-dealer firms' principal sources of revenue, broken down into revenue from IB, brokerage commissions, and all other businesses (such as asset management and proprietary trading). We use these filings to obtain various financial data, including data on our key explanatory variables: the fractions of total brokerage house revenues from IB and from brokerage commissions. Beginning with the names of analyst employers contained in the I/B/E/S Broker Translation file,[11] we search for all available revenue information in x-17a-5 filings from 1994 to 2003.[12] For publicly traded broker-dealer firms, we also use 10-K annual report filings over the sample period to gather information on revenue breakdowns, if necessary. We thus obtain annual data from 1994 to 2003 on IB revenue, brokerage revenue, and other revenue for 188 privately held and 44 publicly traded brokerage houses.[13] For each brokerage house, we match recommendations to the latest broker-year revenue data preceding the recommendation date. Over the sample period, we

[10] The Securities Exchange Act, sections 17(a)–17(e), requires these filings. We accessed them from Thomson Financial's Global Access database and the Securities and Exchange Commission's (SEC's) public reading room in Washington, D.C.

[11] We use the file supplied directly by the Institutional Brokers Estimate System (I/B/E/S) on CD-ROM. This file does not recode the name of an acquired brokerage firm to that of its acquirer for years before the merger.

[12] The electronic availability of x-17a-5 filings is very limited prior to 1994, the year the SEC first mandated electronic form filing. Hence, we do not search for revenue information prior to 1994.

[13] We exclude a small number of firm-years in which the total revenue is negative (for example, because of losses from proprietary trading).

are able to match in this fashion 110,493 I/B/E/S recommendations issued by 4,089 analysts.

All broker-dealer firms are required to publicly disclose their balance sheets as part of their x-17a-5 filings. But a private broker-dealer firm can withhold the public disclosure of its income statement, which contains the revenue breakdown information needed for this study, if the SEC deems that such disclosure would harm the firm's competitive position. Thus, our sample of private securities firms is limited to broker-dealers that disclose their revenue breakdowns in x-17a-5 filings. We examine whether this selection bias affects our main results by separately analyzing the subsample of publicly traded securities firms, for which public disclosure of annual revenue information is mandatory. Our findings do not appear to be affected by this selection bias. All of our results for the subsample of publicly traded securities firms are qualitatively similar to the results for the full sample reported in the article. In the Appendix, we describe the characteristics of disclosing and nondisclosing private securities firms, shed some light on the firms' income statement disclosure decisions, and use a selectivity-corrected probit model to examine whether the resulting selection bias can explain analysts' response to conflicts in these private firms. We find no evidence that selection bias affects our results for these firms.

3.2. Characteristics of Analysts, Their Employers, and Companies Followed

We next measure characteristics of analysts, their employers, and the companies they cover. Prior research (for example, Clement 1999; Jacob, Lys, and Neale 1999) finds that analysts' experience and workloads affect the accuracy and credibility of their research. Using the I/B/E/S Detail History files, we measure an analyst's experience and workloads in terms of all research activity reported in I/B/E/S, including stock recommendations, quarterly and annual earnings-per-share forecasts, and long-term earnings growth forecasts. We measure general research experience as the number of days since an analyst first issued research on any company in the I/B/E/S database and company-specific research experience as the number of days since an analyst first issued research on a particular company. We measure an analyst's workload as the number of different companies or the number of different four-digit I/B/E/S sector industry groups (S/I/Gs)[14] for which the analyst issued research in a given calendar year.

The amount of resources devoted to investment research within brokerage houses also affects the quality of analysts' research (Clement 1999). Larger houses have access to better technology, information, and support staff. Accordingly, we use three measures of brokerage house size: the number of analysts issuing stock recommendations for a brokerage house over the course of a calendar year, book value of total assets, and net sales. All of our subsequent results are qual-

[14] The I/B/E/S sector industry group numbers are six-digit codes that provide information on the industry sectors and subsectors for companies in the I/B/E/S database. We use the first four digits, which correspond to broad industry groupings.

Table 1
Revenue Sources (%) of Analysts' Employers

Recommendation Level	Investment Banking		Brokerage Commission		Sample Size
	Mean	Median	Mean	Median	
5 (Strong buy)	13.94	11.81	29.87	24.09	28,901
4 (Buy)	13.81	11.21	26.68	17.22	37,478
3 (Hold)	12.68	11.13	28.44	24.07	37,883
2 (Sell)	11.61	10.55	23.13	16.12	4,875
1 (Strong sell)	16.27	14.90	33.44	24.95	1,356
p-Value (4 and 5) versus (1 and 2)	.0000	.0000	.0000	.0023	

Note. Shown are the percentages of analyst employer revenues from investment banking and brokerage commissions, by recommendation level. Data are for 110,493 stock recommendations and are drawn from the Institutional Brokers Estimate System U.S. Detail Recommendations History file for 1994–2003.

itatively similar under each of the three size measures. To save space, we report results only of tests based on the first size measure.

To capture the degree to which investors believe that individual analysts have skill in providing timely and accurate research, we use two measures of analysts' reputation. The first is based on *Institutional Investor* (*II*) magazine's All-America Research Team designation. Each year around October 15, *II* mails an issue to subscribers that lists the names of analysts who receive the most votes in a poll of institutional money managers. About 300–400 analysts are identified. We construct a variable that indicates, for each recommendation revision, whether the recommending analyst was named to the first, second, third, or honorable mention team in the latest annual survey. As a complementary, objective measure of analysts' reputation, we use a variable based on the *Wall Street Journal*'s (*WSJ*'s) annual All-Star Analysts Survey. The *WSJ* All-Star Analysts are determined by an explicit set of criteria relating to past stock-picking performance and forecasting accuracy.[15] The survey covers about 50 industries annually and names the top five stock pickers and top five earnings forecasters in each industry.[16]

Tables 1 and 2 report summary data on the characteristics of our sample. In Table 1, both the mean and the median percentages of analyst employer revenues derived from IB decline monotonically over the first four recommendation levels, but these values are the highest for strong sell recommendations. Similarly, it is the brokerage firms issuing strong sell recommendations that generally derive

[15] We recognize that the performance metrics used in the *Wall Street Journal* (*WSJ*) All-Star Analysts Survey are public information and can, in principle, be replicated by investors. However, to the extent that computing and evaluating analysts' performance is a costly activity, being named an All-Star Analyst can still affect an analyst's reputation and credibility.

[16] Since the I/B/E/S Broker Translation File provides only analysts' last names and first initials, in some instances it is not possible to ascertain from the I/B/E/S data alone whether an analyst in our sample was named to the *Institutional Investor* (*II*) or *WSJ* team. For these cases, we determine team membership of analysts from NASD BrokerCheck, an online database (http://www.nasd.com, accessed October 2004) that provides the full names of registered securities professionals as well as their employment and registration histories for the past 10 years. The database also keeps track of analysts' name changes (such as those resulting from marriage).

Table 2
Characteristics of Analysts, Firms, and Companies Followed

Characteristic	Mean	Median	SD	Sample Size
Investment banking revenue (%)	13.60	11.25	11.93	94,892
Brokerage commission revenue (%)	28.74	24.07	24.75	94,892
Analyst's company-specific experience (years)	2.42	1.20	3.29	85,531
Analyst's general experience (years)	6.41	4.90	5.32	85,531
Analysts employed by a firm	86.34	60	79.73	94,618
Companies followed by an analyst	17.24	15	12.93	84,016
Four-digit I/B/E/S S/I/Gs followed by an analyst	3.05	3	1.90	84,014
Institutional Investor All-America stock picker	.005	0	.07	85,531
Institutional Investor All-America Research Team member	.035	0	.18	85,531
Wall Street Journal All-Star stock picker	.018	0	.13	85,531
Wall Street Journal All-Star Analyst	.136	0	.34	85,531
Market capitalization ($ millions)	8,804.46	1,367.22	27,758.81	81,333
Analyst following	9.14	7	6.88	92,869

Note. Data are for 94,892 recommendation revisions and are drawn from the Institutional Brokers Estimate System (I/B/E/S) U.S. Detail Recommendations History file for 1994–2003. Recommendation revisions include recommendation changes as well as initiations, resumptions, and discontinuations of coverage. Analysts' experience is measured from all analyst research activity reported in I/B/E/S, including earnings-per-share forecasts, long-term earnings growth forecasts, and stock recommendations. An analyst is considered to be a top stock picker or team member if he or she appeared in the relevant portion of the most recent analyst survey by *Institutional Investor* or the *Wall Street Journal* at the time of a recommendation revision. Market capitalization is measured 12 months before the end of the current month, and analyst following is measured on the basis of stock recommendation coverage. Market capitalization values are inflation adjusted (with Consumer Price Index numbers and with 2003 as the base year). S/I/G = sector industry group.

the highest percentage of their total revenues from brokerage commissions. Notably, in each of the five categories, the mean percentage of revenue from commissions is about twice as large as the mean percentage of revenue from IB. This fact underscores the importance of trading commissions as a source of revenue for many securities firms. The last column shows that about 95 percent of the recommendations in the sample are at levels 5 (strong buy), 4 (buy), or 3 (hold). Levels 1 (strong sell) and 2 (sell) represent only about 1 percent and 4 percent of all recommendations, respectively.

The data in Table 2 provide a flavor of our sample of analysts and their employers. As noted by Hong, Kubik, and Solomon (2000), careers as analysts tend to be relatively short. The median recommendation is made by an analyst with under 5 years of experience, of which just over a year was spent following a given stock. Stock analysts tend to be highly specialized, following a handful of companies in a few industries. The median recommendation is made by an analyst following 15 companies in three industries who works for a securities firm employing 60 analysts. Being named as an All-America Research Team member by *II* is a rare honor, received by under 5 percent of all analysts in our sample. Finally, the typical company followed is large, with mean (median) market capitalization of about $8.8 billion ($1.4 billion) in inflation-adjusted

2003 dollars. Over the time span of a year, a company is tracked by a mean (median) of 9.1 (7) analysts.

4. Conflicts and the Levels of Analyst Recommendations Net of the Consensus

In this section, we examine whether the level of an analyst's stock recommendation net of the consensus (that is, median) recommendation level is related to the conflicts that he or she faces. We start by ascertaining the level of the outstanding recommendation on each stock by each analyst following it at the end of each quarter (March, June, September, December) from 1995 through 2003. An analyst's recommendation on a stock is included only if it is newly issued, reiterated, or revised in the preceding 12 months.

We estimate a regression explaining individual analysts' net stock recommendation levels at the end of a quarter (which is the recommendation level minus the median recommendation level across all analysts following a stock during the quarter).[17] The regression pools observations across analysts, stocks, and quarters and includes our two main explanatory variables: the percentage of an analyst employer's total revenues from IB and the percentage from brokerage commissions. Following Jegadeesh et al. (2004) and Kadan et al. (forthcoming), who find that momentum is an important determinant of analysts' recommendations, we control for the prior 6-month stock return.

The regression also controls for other factors that can affect the degree of analysts' optimism, such as the size of the company followed and the resources, reputation, experience, and workload of an analyst. As a measure of the resources available to an analyst, a dummy variable is used for a large brokerage house, and it equals one if the firm ranks in the top quartile of all houses in terms of the number of analysts employed during the year. The size of the company followed is measured by the natural logarithm of its market capitalization, measured 12 months before the end of the month. We measure an analyst's reputation by dummy variables that equal one if the recommending analyst was named in the most recent year as an All-America Research Team member by *II* or as an All-Star Analyst by the *WSJ*. An analyst's company-specific research experience is measured by the natural logarithm of one plus the number of days an analyst has been producing research (including earnings-per-share forecasts, long-term growth forecasts, or stock recommendations) on the company. We measure an analyst's workload by the natural logarithm of one plus the number of companies for which he or she produces forecasts or recommendations in the current year.

Finally, we control for industry and time period effects by adding dummy variables for I/B/E/S two-digit S/I/G industries and for each calendar quarter (March 1995, June 1995, and so forth). Since net recommendation levels can

[17] To ensure meaningful variation in the dependent variable, we omit stocks followed by only one analyst in a quarter.

Table 3
Ordered Probit Analysis of Recommendation Levels Net of the Consensus

Explanatory Variable	Coefficient	*z*-Statistic
Investment banking revenue (%)	.4167	17.35
Brokerage commission revenue (%)	.0363	3.00
Prior 6-month stock return	−.0068	−2.89
Large brokerage house dummy	−.0639	−8.60
Company size	.0038	2.89
Institutional Investor All-America Research Team dummy	.0032	.15
Wall Street Journal All-Star Analyst dummy	−.0196	−2.23
Company-specific research experience	.0012	1.42
Number of companies followed	.0070	4.64

Note. The results are from ordered probit regressions explaining individual analysts' stock recommendation levels net of the consensus (that is, median) recommendation level at the end of each quarter (March, June, September, December) for 1995–2003. Observations are excluded if the analyst issued no new or revised recommendation in the preceding 12 months. The regression includes observations pooled across analysts, stocks, and quarters. Data on recommendations are drawn from the Institutional Brokers Estimate System (I/B/E/S) U.S. Detail Recommendations History file for 1994–2003. Investment banking or brokerage commission revenue refer to the percentage of the brokerage firm's total revenues derived from investment banking or brokerage commissions. The large brokerage house dummy is an indicator variable that equals one if a brokerage house is in the top quartile of all houses, based on the number of analysts issuing stock recommendations listed in I/B/E/S in a given calendar year. Company size is the natural logarithm of the market capitalization of the company followed, measured 12 months prior to the end of the current month. The *Institutional Investor* All-America Research Team and *Wall Street Journal* All-Star Analyst dummies are indicator variables that equal one if the recommending analyst was listed as an All-America Research Team member or All-Star Analyst in the most recent analyst ranking. Company-specific research experience is the natural log of one plus the number of days that an analyst has been issuing I/B/E/S research on a company. Number of companies followed equals the natural log of one plus the number of companies followed by an analyst in the current calendar year. The regression includes dummy variables for two-digit I/B/E/S sector industry group industries and for calendar quarters. Test statistics are based on a robust variance estimator. The number of observations is 213,011; the *p*-value of the χ^2 test is <.0001.

take ordered values from −4 (strongly pessimistic) to 4 (strongly optimistic) in increments of .5, we estimate the regression as an ordered probit model.[18] The *Z*-statistics are based on a robust (Huber-White sandwich) variance estimator.

Table 3 shows the regression estimate. The coefficients of IB revenue percentage and commission revenue percentage are both positive. This finding implies that greater conflicts with IB and brokerage businesses lead an analyst to issue a higher recommendation on a stock relative to the consensus. Stocks followed by busier analysts and stocks of larger companies receive higher recommendations relative to the consensus. Stocks that experience a price run-up over the prior 6 months, stocks followed by analysts at large brokerage houses, and stocks followed by *WSJ* All-Star Analysts all receive lower recommendations relative to the consensus. All of these relations are highly statistically significant.

To provide a sense of the magnitude of the main effects of interest, we show in Table 4 the derivatives of the probability of each net recommendation level

[18] Notice that recommendation levels can take integer values from 1 to 5, and the median recommendation can take values from 1 to 5 in increments of .5. See Greene (2003) for a detailed exposition of the ordered probit model.

Table 4

Marginal Effects and Sample Distribution for the Ordered Probit Regression in Table 3

	Recommendation Level Net of the Consensus														
	−4	−3.5	−3	−2.5	−2	−1.5	−1	−.5	0	.5	1	1.5	2	2.5	3
Investment banking revenue (%)	−.00031	−.0002	−.0026	−.0010	−.0199	−.0086	−.0744	−.0321	.0123	.0325	.0671	.0077	.0188	.0002	.0003
Brokerage commission revenue (%)	−.00003	−.00001	−.0002	−.00009	−.0017	−.0008	−.0065	−.0028	.0011	.0028	.0059	.0007	.0016	.00002	.00003
Observed frequency	.0001	.0001	.0016	.0007	.0176	.0094	.1241	.0948	.4940	.0937	.1289	.0111	.0233	.0002	.0003

Note. Shown is the derivative of the probability of each net recommendation level with respect to investment banking or brokerage revenue percentage, estimated from the ordered probit regression in Table 3. Investment banking and brokerage commission revenue refer to the percentage of the brokerage firm's total revenues derived from investment banking and brokerage commissions. The last row shows observed frequency of each net recommendation level as a proportion of the sample of 213,011 observations.

with respect to IB revenue and commission revenue percentages.[19] Thus, for example, a 1-standard-deviation increase in IB revenue percentage increases the probability of an optimistic recommendation (that is, a net recommendation level greater than zero) by .1193 × (.0325 + .0671 + . . . + .0003) = .0151. Compared to the unconditional probability of an optimistic recommendation by an analyst, this represents an increase of about 5.9 percent (.0151/.2575). The effect of a change in commission revenue percentage is much smaller. A 1-standard-deviation increase in commission revenue percentage increases the probability of an optimistic recommendation by .2475 × .01105 = .0027, or about 1 percent (.0027/.2575) of the unconditional probability. Thus, despite possible concerns about a loss of reputation, analysts seem to respond to conflicts of interest, particularly those stemming from IB.

5. Conflicts and Investor Response to Recommendation Revisions

5.1 Stock Price Response

This section examines whether an analyst's credibility with investors is related to the degree of conflict faced. We interpret the reaction of stock prices to a recommendation revision as an indication of an analyst's credibility. Our analysis focuses on revisions in recommendation levels, rather than on recommendation levels per se, because revisions are discrete events that are likely to be salient for investors, and previous research finds that revisions have significant information content (see, for example, Womack 1996; Jegadeesh et al. 2004). To capture the effects of the most commonly observed and economically important types of revisions, we structure our tests around four basic categories: added to strong buy, added to buy or strong buy, dropped from strong buy, and dropped from buy or strong buy.[20] These four categories are defined to include initiations, resumptions, and discontinuations of coverage because such events also reflect analysts' positive or negative views about a company.[21] Thus, for example, we consider a stock to be added to strong buy under two scenarios: (*a*) the recommendation level is raised to strong buy from a lower level or (*b*) coverage is

[19] Notice that, for each explanatory variable, these derivatives sum to zero across all the net recommendation levels.

[20] Our analysis focuses on these four types of revisions instead of the other four (added to strong sell, and so forth) because, as shown in Table 1, sell and strong sell recommendations are quite rare. But note that dropped-from-buy and dropped-from-buy-or-strong-buy revisions can entail movement to the sell or strong sell category.

[21] We use the I/B/E/S Stopped Recommendations file to determine instances in which a brokerage firm discontinued coverage of a company. This file contains numerous cases in which an analyst stops coverage of a stock only to issue a new recommendation a month or two later. Conversations with I/B/E/S representatives indicate that such events likely represent pauses in coverage due to company quiet periods or analysts' reassignments within a brokerage house. We define a stopped coverage event to be a true stoppage only if the analyst does not issue a recommendation on the stock over the subsequent 6 months.

initiated or resumed at the level of strong buy.[22] Defining revisions in this fashion yields a sample of 94,892 recommendation revisions made over the 1994–2003 period.

5.1.1. Average Response

We compute the abnormal return on an upgraded or downgraded stock over day t as the return (including dividends) on the stock minus the return on the Center for Research in Security Prices equal-weighted market portfolio of New York Stock Exchange (NYSE), American Stock Exchange, and NASDAQ stocks. The cumulative abnormal return (CAR) on the stock over days t_1 to t_2 relative to the revision date (day 0) is measured as the sum of the abnormal returns over those days. Table 5 shows mean and median CARs for three windows: days -1 to 0, -1 to 1, and -5 to 5. The t-statistics for the difference of the mean abnormal returns from zero are computed as in Brown and Warner (1985) and are shown in parentheses. The p-values for the Wilcoxon test are reported in parentheses with the medians.

It is clear from Table 5 that recommendation revisions have large effects on stock prices. For example, when a stock is added to the strong-buy list, it experiences a mean abnormal return of about 2 percent over the 2-day revision period. Downgrades have even larger effects on stock prices than do upgrades. Strikingly, the 2-day mean abnormal return around the dropped-from-strong-buy list is -4 percent. Median values are consistently smaller in magnitude than are means, and this finding indicates that some revisions lead to price reactions of a very large magnitude. Mean and median 2-day abnormal returns are statistically different from zero for all four groups of forecast revisions. The magnitudes of abnormal returns are somewhat larger over the 3-day and 11-day windows than over the 2-day window. Overall, these returns are consistent with those found by prior research that examines the average stock price impact of recommendation revisions (for example, Womack 1996; Jegadeesh et al. 2004).

5.1.2. Cross-Sectional Analysis

Table 6 contains cross-sectional regressions of stock price reactions to recommendation revisions over days -1 to 1. The main explanatory variables of interest in these regressions are our revenue-based measures of the magnitudes of IB and brokerage conflicts. We include controls for the size of an analyst's employer, the size of the company followed, and measures of an analyst's reputation, experience, and workload.[23] We estimate a separate regression for each

[22] Note that the definitions of our four recommendation revision groups imply that stocks can be added to a group more than once on a given day. Nonetheless, excluding days on which a stock experiences multiple revisions does not change any of our qualitative results.

[23] Prior research finds that analysts who have more experience, carry lower workloads, or are employed by larger firms tend to generate more precise research (see, for example, Clement 1999; Jacob, Lys, and Neale 1999; Mikhail, Walther, and Willis 1997). In addition, more reputed analysts tend to generate timelier and more accurate research (see, for example, Stickel 1992; Hong and Kubik 2003). We expect such analysts to be more influential with investors.

Table 5
Cumulative Abnormal Returns surrounding Revisions in Analyst Stock Recommendations

	Days −1 to 0			Days −1 to 1			Days −5 to 5		
Recommendation Revision	Mean (*t*-Statistic)	Median (*p*-Value)	*N*	Mean (*t*-Statistic)	Median (*p*-Value)	*N*	Mean (*t*-Statistic)	Median (*p*-Value)	*N*
Upgrades:									
Added to strong buy	.0207	.0109	24,560	.0240	.0130	24,556	.0263	.0187	24,499
	(49.53)*	(.000)		(46.89)*	(.000)		(26.84)*	(.000)	
Added to buy or strong buy	.0149	.0071	36,879	.0165	.0085	36,875	.0207	.0128	36,780
	(46.47)*	(.000)		(42.01)*	(.000)		(27.53)*	(.000)	
Downgrades:									
Dropped from buy or strong buy	−.0337	−.0126	33,322	−.0358	−.0155	33,262	−.0491	−.0287	33,197
	(−56.21)*	(.000)		(−48.75)*	(.000)		(−34.92)*	(.000)	
Dropped from strong buy	−.0399	−.0153	22,825	−.0427	−.0183	22,795	−.0570	−.0326	22,767
	(−49.88)*	(.000)		(−43.58)*	(.000)		(−30.38)*	(.000)	

Note. The sample of recommendation revisions is drawn from the Institutional Brokers Estimate System (I/B/E/S) U.S. Detail Recommendations History file for 1994–2003. Recommendation revisions include recommendation changes and initiations, resumptions, and discontinuations in coverage. Day 0 is the revision date. Recommendation revisions are classified according to the level of any existing recommendation and whether coverage is being initiated or dropped. For example, a revision by an analyst is classified as added to strong buy if the new recommendation is strong buy and (*a*) the previous recommendation was lower than strong buy or (*b*) analyst coverage by the brokerage house is resumed or initiated. A recommendation is classified as dropped from strong buy if the previous recommendation was strong buy and (*a*) the new recommendation is lower than strong buy or (*b*) research coverage on the company is stopped. The *t*-statistics for the difference from zero are computed as in Brown and Warner (1985). The *p*-values for the difference from zero are from a Wilcoxon test.

*Statistically significant at the 1% level in two-tailed tests.

Table 6

Cross-Sectional Regressions of Cumulative Abnormal Returns over Days −1 to +1 surrounding Recommendation Revisions

Explanatory Variable	Added to Strong Buy	Added to Buy or Strong Buy	Dropped from Buy or Strong Buy	Dropped from Strong Buy
Intercept	.0369	.0412	−.2294	−.2224
	(7.66)**	(11.21)**	(−31.31)**	(−29.25)**
Investment banking revenue (%)	−.0262	−.0139	−.0200	−.0354
	(−5.65)**	(−3.57)**	(−2.74)**	(−3.92)**
Brokerage commission revenue (%)	−.0187	−.0148	−.0089	−.0013
	(−6.51)**	(−6.43)**	(−2.39)*	(−.29)
Large brokerage house dummy	.0116	.0088	−.0242	−.0220
	(7.46)**	(6.88)**	(−12.79)**	(−10.25)**
Company size	−.0056	−.0041	−.0004	.0018
	(−16.13)**	(−15.40)**	(−.97)	(3.77)**
Institutional Investor All-America Research Team dummy	.0159	.0122	−.0148	−.0207
	(4.11)**	(3.82)**	(−2.93)**	(−3.28)**
Wall Street Journal All-Star Analyst dummy	.0015	.0013	−.0011	.0045
	(.81)	(.84)	(−.48)	(1.78)
Company-specific research experience	.0017	.0019	.0039	.0018
	(8.42)**	(12.49)**	(7.37)**	(3.21)**
Number of companies followed	−.0012	−.0016	.0007	.0008
	(−2.97)**	(−5.37)**	(1.49)	(1.31)
Observations	19,440	28,665	28,618	19,632
Adjusted R^2	.038	.0240	.028	.035
P-Value of *F*-test	<.0001	<.0001	<.0001	<.0001

Note. Shown are coefficient estimates and (in parentheses) *t*-statistics from ordinary least squares regressions. Day 0 is the recommendation revision date. Data on recommendations are drawn from the Institutional Brokers Estimate System (I/B/E/S) U.S. Detail Recommendations History file for 1994–2003. Investment banking and brokerage commission revenue refer to the percentages of a brokerage firm's total revenues derived from investment banking and brokerage commissions. The large brokerage house dummy is an indicator variable that equals one if a brokerage house is in the top quartile of all houses, based on the number of analysts issuing stock recommendations listed in I/B/E/S in a given calendar year. Company size is the natural logarithm of the market capitalization of the company followed, measured 12 months prior to the end of the current month. The *Institutional Investor* All-America Research Team and *Wall Street Journal* All-Star Analyst dummies are indicator variables that equal one if the recommending analyst was listed as an All-America Research Team member or All-Star Analyst in the most recent analyst ranking. Company-specific research experience is the natural log of one plus the number of days that an analyst has been issuing I/B/E/S research on a company. Number of companies followed equals the natural log of one plus the number of companies followed by an analyst in the current calendar year. All regressions include dummy variables for calendar-year and two-digit I/B/E/S sector industry group industries (not reported). The *t*-statistics are based on a robust variance estimator.

* Statistically significant at the 5% level in two-tailed tests.

** Statistically significant at the 1% level in two-tailed tests.

of the four groups of recommendation revisions. The *t*-statistics based on a robust variance estimator are reported in parentheses.

The coefficient on IB revenue percentage is statistically significantly negative for both upgrades and downgrades. The coefficient on brokerage commission revenue percentage is also negative in all four regressions; it is statistically significant in all cases, except for the dropped-from-strong-buy revisions.[24] Collectively, these results favor the rational discounting hypothesis over the naive investor hypothesis. The magnitudes of these effects are nontrivial. For instance, a 1-standard-deviation increase in IB revenue percentage leads to a change of about −.31 (−.42) percentage points in the 3-day abnormal return around the move to (from) a strong buy recommendation. Similarly, a 1-standard-deviation increase in brokerage commission revenue percentage leads to a change of about −.37 (−.22) percentage points in the corresponding abnormal return around the move to (from) a buy or strong buy recommendation.[25]

The results for control variables are also noteworthy. The dummy variable for a large analyst employer is positively (negatively) related to the market reaction to upgrades (downgrades). This finding is consistent with the idea that revisions by analysts employed at larger brokerage houses (which tend to be more reputable) have more credibility with investors. The size of the company followed is negatively (positively) related to the market reaction to upgrades (downgrades), which is consistent with the notion that, for larger companies, an analyst's recommendation competes with more alternative sources of information and advice.

Revisions by *II* All-America Research Team analysts are positively (negatively) related to the stock price reaction to upgrades (downgrades), which suggests that they wield more influence with investors. This is a notable finding; we are unaware of previous work documenting a relation between an analyst's reputation and the stock price reaction to both upgrades and downgrades. As the coefficient on the *WSJ* All-Star Analyst dummy indicates, however, being designated as a *WSJ* All-Star Analyst does not seem to enhance the credibility of an analyst's recommendations.[26] The absence of an effect here is somewhat

[24] These and all subsequent regression results in this article are qualitatively similar when we winsorize the dependent variable at the first and ninety-ninth percentiles of its distribution.

[25] For each group of revisions (such as added to strong buy), we also estimate the regression after excluding similar revision events that a stock experiences within 3 days of a given revision event. These results are qualitatively similar to those reported in Tables 6 and 8. We also examine the possibility that investors perceived the conflicts to be more severe, and hence discounted them more, in securities firms that were charged by regulators (that is, the 10 firms that were part of the global analyst settlement) than in other firms. We do this by interacting both investment banking (IB) revenue percentage and brokerage commission revenue percentage variables in the regression with binary (0, 1) dummy variables for securities firms that are part of the global analyst settlement and firms that are not. We find no significant differences between the two groups of firms in their coefficients on IB revenue percentage and commission revenue percentage.

[26] Although *II* All-America Research Team and *WSJ* All-Star Analyst dummies both measure aspects of an analyst's reputation, they are not highly correlated. The correlation coefficient is .14 across all upgrades and .13 across all downgrades.

surprising given that the *WSJ* has a much broader readership base than that of *II*. One explanation is that *II* analyst rankings are based on an opinion poll of money managers, who control substantial assets and therefore directly affect stock prices, while *WSJ* rankings are based on strictly quantitative measures of analysts' past stock-picking or forecasting performance.

The market reaction to upgrades is positively related to an analyst's company-specific research experience. This finding suggests that more experienced analysts tend to be more influential with investors. But the reaction to downgrades is also positively related to analysts' experience. Finally, the stock price reaction to upgrades is negatively related to analysts' workload. This finding suggests that busier analysts' opinions tend to get discounted by the market. All of these relations are statistically significant.

5.2. Response of Trading Volume

In this section, we measure analysts' credibility via changes in the volume of trade around recommendation revisions.[27] Revisions of analysts' recommendations can affect trading volumes by inducing investors to rebalance their portfolios to reflect updated beliefs.

5.2.1. Average Response

We compute the abnormal volume for a trading day t as the mean-adjusted share turnover for stock i:[28]

$$e_{it} = v_{it} - v_i, \tag{1}$$

where v_{it} is the trading volume of stock i over day t divided by common shares outstanding on day t and v_i is the mean of v_{it} over days -35 to -6.

The cumulative abnormal volume (CAV) for stock i over days t_1 to t_2 is measured in the following way:

$$\mathrm{CAV}^i t_1, t_2 = \sum_{t=t_1}^{t_2} e_{it}. \tag{2}$$

Table 7 shows mean and median CAV values over three windows surrounding revisions in analyst stock recommendations. Over the 2-day revision period, the mean abnormal volume is positive for both upgrades and downgrades, but its magnitude is substantially larger for downgrades. The move to (from) the strong-buy list increases a stock's trading volume by a mean of about .9 percent (2.6 percent) of the outstanding shares, compared to a normal day's volume. For longer windows, the mean abnormal volumes are substantially higher for down-

[27] Many prior studies have used trading volume to examine investors' response to informational events (see, for example, Shleifer 1986; Jain 1988; Jarrell and Poulsen 1989; Meulbroek 1992; Sanders and Zdanowicz 1992).

[28] This approach has been used in a number of prior studies (for example, Shleifer 1986; Vijh 1994; Michaely and Vila 1996).

Table 7

Cumulative Abnormal Trading Volumes surrounding Announcements of Revisions in Stock Recommendations by Analysts

	Days −1 to 0			Days −1 to 1			Days −5 to 5		
Recommendation revision	Mean (*t*-Statistic)	Median (*p*-Value)	*N*	Mean (*t*-Statistic)	Median (*p*-Value)	*N*	Mean (*t*-Statistic)	Median (*p*-Value)	*N*
Upgrades:									
Added to strong buy	.0086	.0011		.0097	.0015		.0071	.0030	
	(8.89)*	(.000)	24,506	(8.18)*	(.000)	24,502	(3.13)*	(.000)	24,488
Added to buy or strong buy	.0053	.0002		.0058	.0004		.0020	.0008	
	(5.08)*	(.000)	36,800	(4.54)*	(.000)	36,796	(.818)	(.000)	36,766
Downgrades:									
Dropped from buy or strong buy	.0217	.0010		.0265	.0014		.0381	.0039	
	(114.47)*	(.000)	33,291	(114.14)*	(.000)	33,232	(85.70)*	(.000)	33,175
Dropped from strong buy	.0259	.0017		.0315	.0025		.0453	.0057	
	(128.76)*	(.000)	22,808	(127.86)*	(.000)	22,779	(96.03)*	(.000)	22,756

Note. The abnormal volume for stock i on day t is computed from daily Center for Research in Security Prices data as $e_{it} = v_{it} - v_i$, where v_{it} is the volume on day t and v_i is the average volume over days −35 to −6 relative to the recommendation revision date (day 0). All share volumes are normalized by dividing by common shares outstanding on the same day. The *p*-values are from a Wilcoxon test.

*Statistically significant at the 1% level in two-tailed tests.

grades. The median values are lower than the mean values. Each mean and median abnormal volume is statistically greater than zero, with a *p*-value below .01. Clearly, revisions of stock recommendations by analysts generate trading.

5.2.2. Cross-Sectional Analysis

Table 8 presents cross-sectional regressions explaining CAVs over days −1 to 1 surrounding the recommendation revisions. The explanatory variables in the regressions are the same as in regressions of CARs in Section 5.1.2. The results provide strong support for the rational discounting hypothesis. The coefficients on both the IB revenue percentage and commission revenue percentage variables are generally statistically significant and negative (positive) for both groups of upgrades (downgrades). The magnitudes of these effects are nontrivial. For example, a 1-standard-deviation increase in IB revenue percentage leads to a change in the 3-day abnormal volume around the addition (omission) of a stock to (from) the strong-buy list of about −.12 percent (.36 percent) of the outstanding shares; a corresponding change in the commission revenue percentage results in a change in the abnormal volume of about −.15 percent (.22 percent).

Recommendation revisions by larger brokerage houses generate more trading. The abnormal volume is also larger for revisions involving smaller companies. Revisions by *II* All-America Research Team members generate statistically significantly more abnormal volume for the dropped from buy or strong-buy group. Upgrades (downgrades) by more experienced analysts result in larger (smaller) abnormal volumes, and upgrades by busier analysts are less credible.

6. Conflicts and the Performance of Recommendation Revisions

We next consider the investment performance of analysts' recommendation revisions over periods of up to 12 months. Here, the choice of the benchmark used to compute abnormal returns is somewhat more important than it is in Section 5.1, where we measure abnormal returns over a few days around the revision. But the results here are likely to be less sensitive to the benchmark employed than are those in studies of long-run stock performance, where the time period of interest can be as long as 5–10 years (see, for example, Agrawal, Jaffe, and Mandelker 1992; Agrawal and Jaffe 2003).

6.1. Average Performance

We use an approach similar to Barber, Lehavy, and Trueman (2007). To evaluate the performance of stocks over a given window, say, months 1–12 following the month of their inclusion (month 0) in a given group of revisions such as the added-to-strong-buy list, we form a portfolio *p* that initially invests $1 in each recommendation. Each recommended stock remains in the portfolio until month 12 or the month that the stock is either downgraded or dropped from coverage by the securities firm, whichever is earlier. If multiple securities firms recommend a stock in a given month, the stock appears multiple times in the

Table 8

Cross-Sectional Regressions of Cumulative Abnormal Trading Volumes over Days −1 to +1 surrounding Recommendation Revisions

Explanatory Variable	Added to Strong Buy	Added to Buy or Strong Buy	Dropped from Buy or Strong Buy	Dropped from Strong Buy
Intercept	.0083	.0042	.0946	.0828
	(2.65)**	(1.90)	(13.72)**	(15.01)**
Investment banking revenue (%)	−.0100	−.0085	.0140	.0304
	(−3.31)**	(−2.26)*	(2.18)*	(3.63)**
Brokerage commission revenue (%)	−.0057	−.0059	.0087	.0055
	(−1.76)	(−4.13)**	(2.76)**	(1.45)
Large brokerage house dummy	.0058	.0038	.0168	.0171
	(3.72)**	(4.50)**	(11.12)**	(9.48)**
Company size	−.0031	−.0018	−.0023	−.0041
	(−9.54)**	(−12.30)**	(−7.60)**	(−11.40)**
Institutional Investor All-America Research Team dummy	.0035	.0033	.0084	.0046
	(1.74)	(1.88)	(2.32)*	(1.21)
Wall Street Journal All-Star Analyst dummy	.0008	.0013	.0023	−.0006
	(.74)	(1.42)	(1.36)	(−.29)
Company-specific research experience	.0010	.0010	−.0041	−.0019
	(8.39)**	(11.19)**	(−6.18)**	(−4.11)**
Number of companies followed	−.0009	−.0013	−.0001	−.0005
	(−3.49)**	(−6.23)**	(−.38)	(−.99)
Observations	19,431	28,653	28,594	19,619
Adjusted R^2	.025	.019	.030	.042
p-Value of *F*-test	<.0001	<.0001	<.0001	<.0001

Note. Shown are coefficient estimates and (in parentheses) *t*-statistics from ordinary least squares regressions. Day 0 is the recommendation revision date. Data on recommendations are drawn from the Institutional Brokers Estimate System (I/B/E/S) U.S. Detail Recommendations History file for 1994–2003. Investment banking and brokerage commission revenue refer to the percentage of brokerage firm's total revenues derived from investment banking and brokerage commissions. The large brokerage house dummy is an indicator variable that equals one if a brokerage house is in the top quartile of all houses, based on the number of analysts issuing stock recommendations listed in I/B/E/S in a given calendar year. Company size is the natural logarithm of the market capitalization of the company followed, measured 12 months prior to the end of the current month. The *Institutional Investor* All-America Research Team and *Wall Street Journal* All-Star Analyst dummies are indicator variables that equal one if the recommending analyst was listed as an All-America Research Team member or All-Star Analyst in the most recent analyst ranking. Company-specific research experience is the natural log of one plus the number of days that an analyst has been issuing I/B/E/S research on a company. Number of companies followed equals the natural log of one plus the number of companies followed by an analyst in the current calendar year. All regressions include dummy variables for calendar-year and two-digit I/B/E/S sector industry group industries (not reported). The *t*-statistics are based on a robust variance estimator.

*Statistically significant at the 5% level in two-tailed tests.

**Statistically significant at the 1% level in two-tailed tests.

portfolio that month, once for each securities firm with a strong buy recommendation. The portfolio return for calendar month t is given by

$$R_{pt} = \sum_{i=1}^{n_t} x_{it} \times R_{it} \Big/ \sum_{i=1}^{n_t} x_{it}, \tag{3}$$

where R_{it} is the month t return on recommendation i, x_{it} is one plus the compound return on the recommendation from month 1 to month $t-1$ (that is, x_{it} equals one for a stock that was recommended in month t), and n_t is the number of recommendations in the portfolio. This calculation yields a time series of monthly returns for portfolio p.

We compute the abnormal performance of portfolio p as the estimate of the intercept term α_p from the Fama and French (1993) three-factor model. Accordingly, we estimate the following time-series regression for portfolio p:

$$R_{pt} - R_{ft} = \alpha_p + \beta_{1p}(R_{mt} - R_{ft}) + \beta_{2p}\text{SMB}_t + \beta_{3p}\text{HML}_t + \varepsilon_{pt},$$
$$t = \text{January 1994 to December 2003}, \tag{4}$$

where R_f is the risk-free rate, R_m is the return on the value-weighted market index, SMB equals the monthly return on a portfolio of small firms minus the return on a portfolio of big firms, and HML is the monthly return on a portfolio of firms with high book-to-market ratio minus the return on a portfolio of firms with low book-to-market ratio. The error term in the regression is denoted ε. The time series of monthly returns on $R_m - R_f$, SMB, and HML are obtained from Kenneth French's Web site.[29] We repeat this procedure for each time window of interest, such as months 1–3, and for each group of revisions, such as the dropped-from-strong-buy list.

Table 9 shows the performance of analysts' recommendation revisions. Over the period of 3 months following the month of recommendation revision, the average abnormal returns for upgrades are positive, and the returns for downgrades are negative. The magnitudes of these returns are nontrivial. For example, the addition of a stock to the strong-buy list has an abnormal monthly return of about .875 percent, or about 2.62 percent over the 3-month period. The pattern is generally similar over longer windows. For example, over months 1–12, the abnormal monthly return for the added-to-strong-buy list is .679 percent, or about 8.15 percent over the 12-month period. The abnormal returns are significantly different from zero for upgrades in all cases; they are statistically insignificant for downgrades in all cases except one.

[29] Kenneth R. French, Fama/French Factors (file F-F_Research_Data_Factors.zip at http://mba.tuck.dartmouth.edu/pages/faculty/ken.french/data_library.html).

Table 9
Medium-Term Investment Performance of Recommendation Revisions

	Months 1–3		Months 1–6		Months 1–12	
Portfolio	Abnormal Monthly Return (%)	*t*-Statistic	Abnormal Monthly Return (%)	*t*-Statistic	Abnormal Monthly Return (%)	*t*-Statistic
Added to strong buy	.875	6.12**	.758	6.12**	.679	5.70**
Added to buy or strong buy	.586	4.49**	.511	4.82**	.503	5.38**
Dropped from buy or strong buy	−.361	−1.60	−.260	−1.28	−.072	−.44
Dropped from strong buy	−.367	−1.58	−.395	−2.00*	−.231	−1.49

Note. Abnormal returns are reported for three event windows relative to the month of revision (month 0) and are computed using an approach similar to that in Barber, Lehavy, and Trueman (2007). The abnormal return is the estimated intercept from a time-series regression of 114 monthly portfolio returns using the Fama and French (1993) three-factor model.

* Statistically significant at the 5% level in two-tailed tests.

** Statistically significant at the 1% level in two-tailed tests.

6.2. Cross-Sectional Analysis

Table 10 shows the results of a regression similar to that in Section 5.1.2, except that the dependent variable here is the average monthly abnormal return for a firm over months 1–12 following the month of a recommendation revision. We compute this abnormal return by estimating a time-series regression similar to that in equation (4) over months 1–12 for each stock in a sample of recommendation revisions. The intercept from this regression is our estimate of the performance of the recommendation revision. Observations involving recommendation revisions on a stock that occur within 12 months of an earlier revision are omitted from each regression.[30]

In each regression result reported in Table 10, the coefficients of IB revenue percentage and commission revenue percentage are not statistically significantly different from zero. These results favor the rational discounting hypothesis, at least for the marginal investor. The performance of both groups of recommendation upgrades is negatively related to company size; the performance of one group of downgrades is positively related to the dummy variable for *WSJ* All-Star Analysts. None of the other variables is statistically significant.

7. Bubble versus Postbubble Periods

We next exploit the fact that our sample spans both the late-1990s U.S. stock bubble and a postbubble period. During the bubble period, initial public offerings, merger activities, and stock prices were near record highs, and media attention was focused on analysts' pronouncements. We therefore examine whether analysts' behavior and investors' responses to analysts' recommendations differed during the bubble and postbubble periods. Given the euphoria on Wall

[30] The results are qualitatively similar when we include these observations.

Table 10

Cross-Sectional Regressions of Average Monthly Abnormal Returns following Recommendation Revisions over Months 1–12

Explanatory Variable	Added to Strong Buy	Added to Buy or Strong Buy	Dropped from Buy or Strong Buy	Dropped from Strong Buy
Intercept	.0523	.0089	−.0646	−.0821
	(1.81)	(.49)	(−6.81)**	(−6.55)**
Investment banking revenue (%)	−.0089	−.0018	.0042	−.0068
	(−1.23)	(−.29)	(.64)	(−.87)
Brokerage commission revenue (%)	.0064	.0059	.0057	.0031
	(1.32)	(1.54)	(1.21)	(.75)
Large brokerage house dummy	.0009	−.0027	.0016	.0015
	(.38)	(−1.32)	(.72)	(.77)
Company size	−.0013	−.0017	−.0007	−.0007
	(−2.74)**	(−4.18)**	(−1.71)	(−1.54)
Institutional Investor All-America analyst dummy	−.0029	.0001	−.0016	−.0009
	(−.58)	(.01)	(−.44)	(−.23)
Wall Street Journal All-Star Analyst dummy	.0031	.0002	−.0029	.0056
	(1.24)	(.12)	(−1.42)	(2.29)*
Company-specific research experience	.0004	.0004	.0004	.0004
	(1.08)	(1.80)	(.76)	(.92)
Number of companies followed	−.0011	−.0008	−.0002	−.0002
	(−1.61)	(−1.79)	(−.45)	(−.47)
Observations	6,411	8,851	10,644	8,368
Adjusted R^2	.026	.023	.019	.020
p-Value of *F*-test	<.0001	<.0001	<.0001	<.0001

Note. Shown are the coefficient estimates and (in parentheses) *t*-statistics from ordinary least squares regressions. Month 0 is the month of recommendation revision. The abnormal return is the estimated intercept from a time-series regression of monthly portfolio returns in accordance with the Fama and French (1993) three-factor model. Data on recommendations are drawn from the Institutional Brokers Estimate System (I/B/E/S) U.S. Detail Recommendations History file for 1994–2003. Investment banking and brokerage commission revenue data refer to the percentage of the brokerage firm's total revenues derived from investment banking and brokerage commissions. The large brokerage house dummy is an indicator variable that equals one if a brokerage house is in the top quartile of all houses, based on the number of analysts issuing stock recommendations on I/B/E/S in a given calendar year. Company size is the natural logarithm of the market capitalization of the company followed, measured 12 months prior to the end of the current month. The *Institutional Investor* All-America Research Team and *Wall Street Journal* All-Star Analyst dummies are indicator variables that equal one if the recommending analyst was listed as an All-America Research Team member or All-Star Analyst in the most recent analyst ranking. Company-specific research experience is the natural log of one plus the number of days that an analyst has been issuing I/B/E/S research on a company. Number of companies followed equals the natural log of one plus the number of companies followed by an analyst in the current calendar year. All regressions include dummy variables for calendar-year and two-digit I/B/E/S sector industry group industries (not reported). The *t*-statistics are based on a robust variance estimator.

* Statistically significant at the 5% level in two-tailed tests.

** Statistically significant at the 1% level in two-tailed tests.

Table 11
Ordered Probit Regression of Recommendation Levels Net of the Consensus for Bubble versus Postbubble Periods

	Bubble	Postbubble	*p*-Value
Investment banking revenue (%)	.5103*	.3089*	<.001
Brokerage revenue (%)	−.1868*	.2286*	<.001

Note. The explanatory variables are as in Table 3, except that (*a*) the investment banking revenue and brokerage commission revenue percentage variables are interacted with dummy variables for the bubble or postbubble period and (*b*) calendar-quarter dummies are replaced with a postregulation indicator (which is equal to one for quarters after May 2002). Shown are the coefficient estimates of investment banking and brokerage revenue percentage variables for the bubble and postbubble periods and the *p*-value for the difference in the coefficient estimate between the two periods. All test statistics use robust variance estimators.
* Statistically significant at the 1% level in two-tailed tests.

Street and among investors during the bubble, analysts appear to have been under acute pressure to generate IB fees and brokerage commissions. As for the response of investors, the rational discounting hypothesis predicts greater discounting of analysts' opinions during this period in response to heightened conflicts, while the naive investor hypothesis predicts less discounting.

We estimate regressions similar to those for relative recommendation levels (Table 3), those for announcement abnormal returns (Table 6), those for announcement abnormal volumes (Table 8), and those for 12-month investment performance of recommendation revisions (Table 10), except that we now interact IB revenue percentage and commission revenue percentage with dummy variables for the bubble (January 1996–March 2000) and postbubble (April 2000–December 2003) periods. Accordingly, we restrict the sample period for these regressions to January 1996–December 2003. For regressions corresponding to those with results shown in Table 3, we also replace the calendar-quarter dummies with a postregulation indicator (equal to one for quarters ending after May 2002). In May 2002, both the NYSE and the National Association of Securities Dealers considerably tightened the regulations on the production and dissemination of sell-side analyst research.[31] The findings of Barber et al. (2006) and Kadan et al. (forthcoming) suggest that these regulations exerted a downward pressure on recommendation levels. The regression results are presented in Tables 11 and 12. To save space, we report only the coefficient estimates for IB revenue percentage and commission revenue percentage.

The results in Table 11 show that analysts appear to have inflated their recommendations in response to IB conflicts during both the bubble and postbubble periods. But the magnitude of this effect is substantially greater during the bubble period than during the postbubble period. This difference is statistically significant. The magnitude of the effect is smaller for brokerage conflicts than for IB conflicts during both periods. In fact, the effect for brokerage conflicts is negative

[31] See NYSE Amended Rule 472, "Communications with the Public," and National Association of Securities Dealers Rule 2711, "Research Analysts and Research Reports."

Table 12

Ordinary Least Squares Regressions of Abnormal Returns, Abnormal Volumes, and Abnormal Stock Performance for Bubble and Postbubble Periods

	Added to Strong Buy			Added to Buy or Strong Buy			Dropped from Buy or Strong Buy			Dropped from Strong Buy		
	Bubble	Postbubble	*p*-Value	Bubble	Postbubble	*p*-Value	Bubble	Postbubble	*p*-Value	Bubble	Postbubble	*p*-Value
CARs, days −1 to 1:												
Investment banking revenue (%)	−.0248**	−.0120	.083	−.0121**	−.0080	.517	−.0125	−.0379**	.027	−.0361**	−.0345**	.908
Brokerage revenue (%)	−.0114**	−.0105**	.827	−.0099**	−.0110**	.720	−.0063	−.0208**	.003	.0017	−.0114*	.024
CAVs, days −1 to 1:												
Investment banking revenue (%)	−.0076	−.0052	.655	−.0065	−.0082*	.699	.0257**	.0130	.214	.0555**	.0153	.002
Brokerage revenue (%)	−.0042	−.0008	.376	−.0054**	−.0031	.179	.0106*	.0139**	.521	.0046	.0141**	.056
Average monthly CARs, months 1–12:												
Investment banking revenue (%)	−.0016	−.0151	.273	.00001	.0083	.420	−.0085	.0223**	.003	−.0123	−.0051	.564
Brokerage revenue (%)	.0069	.0108	.511	.0086	.0096	.842	.0035	.0136	.101	−.0036	.0091	.019

Note. The explanatory variables are as in Tables 6, 8, and 10, except that the investment banking revenue and brokerage commission revenue percentage variables are interacted with dummy variables for the bubble or postbubble period. Shown are the coefficient estimates of the investment banking and brokerage revenue percentage variables for the bubble and postbubble periods and the *p*-value for the difference in the coefficient estimate between the two periods. Day (month) 0 is the recommendation revision date. All test statistics use robust variance estimators. CAR = cumulative abnormal return; CAV = cumulative abnormal volume.

*Statistically significant at the 5% level in two-tailed tests.

**Statistically significant at the 1% level in two-tailed tests.

during the bubble; it is positive and statistically significantly higher during the postbubble period.

Table 12 shows that, in regressions of 3-day abnormal returns, the coefficients of both IB revenue percentage and commission revenue percentage are negative and statistically significant during the bubble period for both groups of upgrades. For the added-to-strong-buy group, the coefficient of IB revenue percentage is significantly lower during the bubble period than during the postbubble period. For downgrades, the coefficients of both variables are generally negative in both periods, and they are statistically significantly lower during the postbubble period.

In regressions of 3-day abnormal volumes, the coefficients of IB revenue percentage and commission revenue percentage are negative for upgrades and positive for downgrades in all cases, both during and after the bubble. These coefficients are not statistically significantly different between the bubble and postbubble periods for both groups of upgrades and one group of downgrades. For the dropped-from-strong-buy group, the coefficient of IB revenue percentage is statistically significantly larger during the bubble period than during the postbubble period, but the coefficient of the commission revenue percentage is statistically significantly smaller. In regressions of 12-month postrecommendation stock performance, the coefficients of both variables are statistically insignificant both during and after the bubble period in nearly all cases, and this finding is consistent with the results shown in Table 10 for the full sample period.

Overall, analysts appear to respond to IB conflicts both during and after the bubble, but the magnitude of their response declines during the postbubble period. Perversely, while analysts do not seem to respond to brokerage conflicts during the bubble, they appear to do so after the bubble. Perhaps the intense regulatory and media focus on IB conflicts has led analysts to look for alternative avenues. Did investors discount conflicted analysts' opinions more during the bubble than in the postbubble period? The answer to this question is unclear. However, our evidence does not support the notion that investors threw caution to the wind during the bubble.

8. Summary and Conclusions

Following the collapse of the late-1990s U.S. stock market bubble, there has been a widespread hue and cry from investors and regulators over the conflicts of interest faced by Wall Street stock analysts. The discovery of e-mail messages, in which analysts were privately disparaging stocks that they were touting publicly, led to the landmark $1.4 billion settlement between a number of leading Wall Street firms and securities regulators in April 2003. The settlement requires the firms to disclose IB conflicts in analyst reports and imposes a variety of restrictions designed to strengthen the firewalls that separate research from IB. Part of the settlement funds are set aside for investor education and for research produced by independent firms. The settlement basically presumes that analysts

respond to the conflicts by inflating their stock recommendations and that investors take analysts' recommendations at face value.

Consistent with the view of the media and regulators, we find that optimism in stock recommendations is positively related to the importance of both IB and brokerage businesses to an analyst's employer. This pattern is more pronounced during the late-1990s stock market bubble with respect to IB conflicts. However, we provide several pieces of empirical evidence that suggest that investors are sophisticated enough to adjust for this bias. First, the short-term reactions of both stock prices and trading volumes to recommendation upgrades vary negatively with the magnitude of potential IB or brokerage conflicts faced by analysts. For instance, over the 3 days surrounding an upgrade to strong buy, a 1-standard-deviation increase in the proportion of revenue from IB is associated with a .31 percentage point decrease in abnormal returns and a .12 percentage point decrease in abnormal volume. These results suggest that investors ascribe lower credibility to an analyst's upgrade when the analyst is subject to greater pressures to issue an optimistic view. For downgrades, conflict severity varies negatively with the short-term stock price reaction and positively with the short-term trading volume impact. This pattern is consistent with the idea that investors perceive an analyst to be more credible if he or she is willing to voice an unfavorable opinion on a stock despite greater pressures to be optimistic.

Second, we find no evidence that the 1-year investment performance of recommendation revisions is related to the magnitude of analysts' conflicts, either for upgrades or for downgrades. This finding suggests that, on average, investors properly discount an analyst's opinions for potential conflicts at the time the opinion is issued. Finally, investors discounted conflicted analysts' opinions during the late-1990s stock bubble, even in the face of the prevailing market euphoria. This evidence does not support the popular view that recommendations of sell-side analysts led investors to throw caution to the wind during the bubble period.

Overall, our empirical findings suggest that while analysts do respond to IB and brokerage conflicts by inflating their stock recommendations, the market discounts these recommendations after taking analysts' conflicts into account. These findings are reminiscent of the story of the nail soup told by Brealey and Myers (1991), except that here analysts (rather than accountants) are the ones who put the nail in the soup and investors (rather than analysts) are the ones to take it out. Our finding that the market is not fooled by biases stemming from conflicts of interest echoes similar findings in the literature on conflicts of interest in universal banking (for example, Kroszner and Rajan 1994, 1997; Gompers and Lerner 1999) and on bias in the financial media (for example, Bhattacharya et al., forthcoming; Reuter and Zitzewitz 2006). Finally, while we cannot rule out the possibility that some investors may have been naive, our findings do not support the notion that the marginal investor was systematically misled over the last decade by analysts' recommendations.

Appendix

This Appendix describes the characteristics of disclosing and nondisclosing private securities firms, sheds some light on their decisions to publicly disclose their income statements, and examines whether the resulting selection bias affects our main results in Table 3. Table A1 provides summary statistics of recommendation levels and characteristics of disclosing and nondisclosing private securities firms. Compared with nondisclosing firms, disclosing firms tend to be smaller and more liquid and issue somewhat more optimistic stock recommendations. The mean recommendation level is slightly higher for disclosing firms than for nondisclosing firms. The median disclosing firm is smaller and holds more liquid assets than the median nondisclosing firm. All these differences are statistically significant. The two groups of firms have similar financial leverage ratios and 2-year growth rates in total assets.

We next examine cross-sectional determinants of a private securities firm's decision to disclose its income statement. In an excellent review of the corporate disclosure literature, Healy and Palepu (2001) point out that a firm is more willing to voluntarily disclose financial information when it needs to raise external financing and when it is less concerned that the disclosure would damage its competitive position in product markets. Ceteris paribus, firms with greater growth opportunities, higher financial leverage, and less liquid resources are more likely to need external financing. They are more likely to be open with potential investors by disclosing financial information, including their income statements. Similarly, smaller firms are likely to have greater need for external financing as they try to grow. In addition, given the intense competition in the securities business, smaller private firms are also likely to be more willing to disclose their profits and profitability because they have less business at stake. For both reasons, smaller firms are likely to be more willing to disclose financial information. We control for firm size by the natural logarithm of one plus total assets in millions of dollars, for growth opportunities by the 2-year growth rate of total assets, for financial leverage by the ratio of long-term debt to total assets, and for liquidity by the ratio of cash and equivalents to total assets. We estimate a probit regression of DISCLOSER, which equals one for a disclosing firm and is zero otherwise.

In accordance with the predictions of corporate disclosure theory, the coefficients on firm size and liquidity are negative, and the coefficient on growth is positive. Contrary to the prediction, however, the coefficient on leverage is negative. All of these coefficients are highly statistically significant. The pseudo-R^2-value of this model is .08. To save space, these results are not shown in a table.

Finally, we examine whether the selection bias caused by a private securities firm's disclosure choice (and, consequently, the availability of data on IB revenue percentage and commission revenue percentage) affects our main results in Table 3. While there is no Heckman selectivity correction for the ordered probit model, there is one for the regular probit model. So we define a binary variable to

Table A1
Summary Statistics for Disclosing and Nondisclosing Private Securities Firms

	Mean			Median			Sample Size	
Variable	Disclosers	Nondisclosers	*P*-Value of *t*-Test	Disclosers	Nondisclosers	*p*-Value of Rank Sum Test	Disclosers	Nondisclosers
Recommendation level:								
Level	3.902	3.810	<.001	4	4	<.001	62,417	181,068
Level minus median level	.036	.010	<.001	0	0	<.001	62,417	181,068
Firm size:								
Total assets ($ millions)	383.37	1,863.52	<.001	4.05	28.43	<.001	365	615
Book equity ($ millions)	26.40	68.98	<.001	1.97	10.56	<.001	365	615
Financial leverage:								
Long-term debt to total assets	.0539	.0653	.253	0	.002	.004	365	615
Total debt to total assets	.0685	.1823	.295	0	.018	<.001	365	615
Liquidity: cash and equivalents to total assets	.2392	.1816	.001	.101	.052	.0001	365	615
2-Year growth rate	.0849	.0697	.440	.052	.020	.099	246	541

Note. Disclosers are brokers that publicly disclose their income statements, while nondisclosers are brokers that do not disclose them. The statistics for recommendation level are computed from individual analysts' recommendation levels at the end of each quarter in the sample. The median recommendation level is computed at the end of each quarter and is based on all analysts recommending a stock. The statistics for broker characteristics are computed across broker years. The firm size statistics are inflation adjusted (with Consumer Price Index numbers and with 2003 as the base year). The 2-year growth rate is $(\text{Total assets}_t / \text{Total assets}_{t-2})^{1/2} - 1$.

measure an optimistic recommendation that equals one if an analyst's recommendation level on a stock exceeds the consensus level and equals zero otherwise. We then replace the dependent variable in the regression in Section 4 with this optimistic recommendation dummy. Using the subsample of private securities firms, we estimate the resulting equation in two ways: (*a*) with a regular probit model and (*b*) with a Heckman selectivity-corrected probit model, where we use the equation described in the second paragraph of this Appendix as the selection equation. When we use approach *b,* the coefficient of the selection term (that is, the inverse Mills ratio) is statistically significant in the second-stage probit regression. What is more important for our purposes is that the sign, magnitude, and statistical significance of our main explanatory variables, the IB revenue percentage and the commission revenue percentage, are similar in the regular probit and the Heckman-corrected probit regressions. These results do not support the idea that our main findings are driven by the selection bias caused by a private securities firm's decision to disclose its revenue breakdown. To save space, these results are not shown in a table.

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U.S. Capital Markets Performance by
Asset Class 1926–2017

Appendix A-1

Large-Capitalization Stocks: Total Return
From 1926 to 2017

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan–Dec*
1987	0.1347	0.0395	0.0289	-0.0089	0.0087	0.0505	0.0507	0.0373	-0.0219	-0.2154	-0.0824	0.0761	1987	0.0525
1988	0.0421	0.0466	-0.0309	0.0111	0.0086	0.0459	-0.0038	-0.0339	0.0426	0.0278	-0.0143	0.0174	1988	0.1661
1989	0.0732	-0.0249	0.0233	0.0519	0.0405	-0.0057	0.0903	0.0195	-0.0041	-0.0232	0.0204	0.0240	1989	0.3169
1990	-0.0671	0.0129	0.0265	-0.0249	0.0975	-0.0067	-0.0032	-0.0904	-0.0487	-0.0043	0.0646	0.0279	1990	-0.0310
1991	0.0436	0.0715	0.0242	0.0024	0.0431	-0.0458	0.0466	0.0237	-0.0167	0.0134	-0.0403	0.1144	1991	0.3047
1992	-0.0186	0.0130	-0.0194	0.0294	0.0049	-0.0149	0.0409	-0.0205	0.0118	0.0035	0.0341	0.0123	1992	0.0762
1993	0.0084	0.0136	0.0211	-0.0242	0.0268	0.0029	-0.0040	0.0379	-0.0077	0.0207	-0.0095	0.0121	1993	0.1008
1994	0.0340	-0.0271	-0.0436	0.0128	0.0164	-0.0245	0.0328	0.0410	-0.0245	0.0225	-0.0364	0.0148	1994	0.0132
1995	0.0259	0.0390	0.0295	0.0294	0.0400	0.0232	0.0332	0.0025	0.0422	-0.0036	0.0439	0.0193	1995	0.3758
1996	0.0340	0.0093	0.0096	0.0147	0.0258	0.0038	-0.0442	0.0211	0.0563	0.0276	0.0756	-0.0198	1996	0.2296
1997	0.0625	0.0078	-0.0411	0.0597	0.0609	0.0448	0.0796	-0.0560	0.0548	-0.0334	0.0463	0.0172	1997	0.3336
1998	0.0111	0.0721	0.0512	0.0101	-0.0172	0.0406	-0.0106	-0.1446	0.0641	0.0813	0.0606	0.0576	1998	0.2858
1999	0.0418	-0.0311	0.0400	0.0387	-0.0236	0.0555	-0.0312	-0.0049	-0.0274	0.0633	0.0203	0.0589	1999	0.2104
2000	-0.0502	-0.0189	0.0978	-0.0301	-0.0205	0.0247	-0.0156	0.0621	-0.0528	-0.0042	-0.0788	0.0049	2000	-0.0910
2001	0.0355	-0.0912	-0.0634	0.0777	0.0067	-0.0243	-0.0098	-0.0626	-0.0808	0.0191	0.0767	0.0088	2001	-0.1189
2002	-0.0146	-0.0193	0.0376	-0.0606	-0.0074	-0.0712	-0.0780	0.0066	-0.1087	0.0880	0.0589	-0.0587	2002	-0.2210
2003	-0.0262	-0.0150	0.0097	0.0824	0.0527	0.0128	0.0176	0.0195	-0.0106	0.0566	0.0088	0.0524	2003	0.2868
2004	0.0184	0.0139	-0.0151	-0.0157	0.0137	0.0194	-0.0331	0.0040	0.0108	0.0153	0.0405	0.0340	2004	0.1088
2005	-0.0244	0.0210	-0.0177	-0.0190	0.0318	0.0014	0.0372	-0.0091	0.0081	-0.0167	0.0378	0.0003	2005	0.0491
2006	0.0265	0.0027	0.0124	0.0134	-0.0288	0.0014	0.0062	0.0238	0.0258	0.0326	0.0190	0.0140	2006	0.1579
2007	0.0151	-0.0196	0.0112	0.0443	0.0349	-0.0166	-0.0310	0.0150	0.0374	0.0159	-0.0418	-0.0069	2007	0.0549
2008	-0.0600	-0.0325	-0.0043	0.0487	0.0130	-0.0843	-0.0084	0.0145	-0.0891	-0.1679	-0.0718	0.0106	2008	-0.3700
2009	-0.0843	-0.1065	0.0876	0.0957	0.0559	0.0020	0.0756	0.0361	0.0373	-0.0186	0.0600	0.0193	2009	0.2646
2010	-0.0360	0.0310	0.0603	0.0158	-0.0799	-0.0523	0.0701	-0.0451	0.0892	0.0380	0.0001	0.0668	2010	0.1506
2011	0.0237	0.0343	0.0004	0.0296	-0.0113	-0.0167	-0.0203	-0.0543	-0.0703	0.1093	-0.0022	0.0102	2011	0.0211
2012	0.0448	0.0432	0.0329	-0.0063	-0.0601	0.0412	0.0139	0.0225	0.0258	-0.0185	0.0058	0.0091	2012	0.1600
2013	0.0518	0.0136	0.0375	0.0193	0.0234	-0.0134	0.0509	-0.0290	0.0314	0.0460	0.0305	0.0253	2013	0.3239
2014	-0.0346	0.0457	0.0084	0.0074	0.0235	0.0207	-0.0138	0.0400	-0.0140	0.0244	0.0269	-0.0025	2014	0.1369
2015	-0.0300	0.0575	-0.0158	0.0096	0.0129	-0.0194	0.0210	-0.0603	-0.0247	0.0844	0.0030	-0.0158	2015	0.0138
2016	-0.0496	-0.0013	0.0678	0.0039	0.0180	0.0026	0.0369	0.0014	0.0002	-0.0182	0.0370	0.0198	2016	0.1196
2017	0.0190	0.0397	0.0012	0.0103	0.0141	0.0062	0.0206	0.0031	0.0206	0.0233	0.0307	0.0111	2017	0.2183

*Compound annual return

Appendix A-2

Large-Capitalization Stocks: Income Returns
From 1926 to 2017

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Jan–Dec*

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2017

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number	Name of Registrant, State of Incorporation, Address of Principal Executive Offices and Telephone Number	IRS Employer Identification Number
1-9894	ALLIANT ENERGY CORPORATION (a Wisconsin corporation) 4902 N. Biltmore Lane Madison, Wisconsin 53718 Telephone (608) 458-3311	39-1380265
1-4117	INTERSTATE POWER AND LIGHT COMPANY (an Iowa corporation) Alliant Energy Tower Cedar Rapids, Iowa 52401 Telephone (319) 786-4411	42-0331370
0-337	WISCONSIN POWER AND LIGHT COMPANY (a Wisconsin corporation) 4902 N. Biltmore Lane Madison, Wisconsin 53718 Telephone (608) 458-3311	39-0714890

This combined Form 10-K is separately filed by Alliant Energy Corporation, Interstate Power and Light Company and Wisconsin Power and Light Company. Information contained in the Form 10-K relating to Interstate Power and Light Company and Wisconsin Power and Light Company is filed by each such registrant on its own behalf. Each of Interstate Power and Light Company and Wisconsin Power and Light Company makes no representation as to information relating to registrants other than itself.

Securities registered pursuant to Section 12(b) of the Act:

	Title of Class	Name of Each Exchange on Which Registered
Alliant Energy Corporation	Common Stock, $0.01 Par Value	New York Stock Exchange
Interstate Power and Light Company	5.100% Series D Cumulative Perpetual Preferred Stock, $0.01 Par Value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrants are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.
Yes ☒ No ☐

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ☐ No ☒

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports) and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File

required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrants are large accelerated filers, accelerated filers, non-accelerated filers, smaller reporting companies, or emerging growth companies. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company	Emerging Growth Company
Alliant Energy Corporation	☒				
Interstate Power and Light Company			☒		
Wisconsin Power and Light Company			☒		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the voting and non-voting common equity held by nonaffiliates as of June 30, 2017:

Alliant Energy Corporation	$9.3 billion
Interstate Power and Light Company	$—
Wisconsin Power and Light Company	$—

Number of shares outstanding of each class of common stock as of January 31, 2018:

Alliant Energy Corporation	Common stock, $0.01 par value, 231,356,336 shares outstanding
Interstate Power and Light Company	Common stock, $2.50 par value, 13,370,788 shares outstanding (all of which are owned beneficially and of record by Alliant Energy Corporation)
Wisconsin Power and Light Company	Common stock, $5 par value, 13,236,601 shares outstanding (all of which are owned beneficially and of record by Alliant Energy Corporation)

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement relating to Alliant Energy Corporation's 2018 Annual Meeting of Shareowners are, or will be upon filing with the Securities and Exchange Commission, incorporated by reference into Part III hereof.

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DEFINITIONS

The following abbreviations or acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	Definition	Abbreviation or Acronym	Definition
2018 Alliant Energy Proxy Statement	Alliant Energy's Proxy Statement for the 2018 Annual Meeting of Shareowners	GHG	Greenhouse gases
AEF	Alliant Energy Finance, LLC	IPL	Interstate Power and Light Company
AFUDC	Allowance for funds used during construction	IRS	Internal Revenue Service
Alliant Energy	Alliant Energy Corporation	ITC	ITC Midwest LLC
AOCL	Accumulated other comprehensive loss	IUB	Iowa Utilities Board
ARO	Asset retirement obligation	KWh	Kilowatt-hour
ATC	American Transmission Company LLC	Marshalltown	Marshalltown Generating Station
ATC Investment	Investment in American Transmission Company LLC and ATC Holdco LLC	MDA	Management's Discussion and Analysis of Financial Condition and Results of Operations
ATI	AE Transco Investments, LLC	MGP	Manufactured gas plant
CA	Certificate of authority	MISO	Midcontinent Independent System Operator, Inc.
CAA	Clean Air Act	MW	Megawatt
CCR	Coal combustion residuals	MWh	Megawatt-hour
CO2	Carbon dioxide	N/A	Not applicable
Corporate Services	Alliant Energy Corporate Services, Inc.	NAAQS	National Ambient Air Quality Standards
CPCN	Certificate of Public Convenience and Necessity	Note(s)	Combined Notes to Consolidated Financial Statements
CRANDIC	Cedar Rapids and Iowa City Railway Company	NOx	Nitrogen oxide
CSAPR	Cross-State Air Pollution Rule	OIP	Alliant Energy 2010 Omnibus Incentive Plan
CWIP	Construction work in progress	OPEB	Other postretirement benefits
DAEC	Duane Arnold Energy Center	PPA	Purchased power agreement
DATC	Duke-American Transmission Company, LLC	PSCW	Public Service Commission of Wisconsin
DCP	Alliant Energy Deferred Compensation Plan	Receivables Agreement	Receivables Purchase and Sale Agreement
DLIP	Alliant Energy Director Long Term Incentive Plan	RES	Renewable energy standards
Dth	Dekatherm	Riverside	Riverside Energy Center
EEP	Energy efficiency plan	SCR	Selective catalytic reduction
EGU	Electric generating unit	SEC	Securities and Exchange Commission
EPA	U.S. Environmental Protection Agency	SO2	Sulfur dioxide
EPB	Emissions plan and budget	Tax Reform	Tax Cuts and Jobs Act
EPS	Earnings per weighted average common share	U.S.	United States of America
FERC	Federal Energy Regulatory Commission	VEBA	Voluntary Employees' Beneficiary Association
Financial Statements	Consolidated Financial Statements	VIE	Variable interest entity
FTR	Financial transmission right	WACC	Weighted-average cost of capital
Fuel-related	Electric production fuel and purchased power	Whiting Petroleum	Whiting Petroleum Corporation
FWEC	Forward Wind Energy Center	WPL	Wisconsin Power and Light Company
GAAP	U.S. generally accepted accounting principles	WPL Transco	WPL Transco, LLC

FORWARD-LOOKING STATEMENTS

Statements contained in this report that are not of historical fact are forward-looking statements intended to qualify for the safe harbors from liability established by the Private Securities Litigation Reform Act of 1995. These forward-looking statements can be identified as such because the statements include words such as "may," "believe," "expect," "anticipate," "plan," "project, "will," "projections," "estimate," or other words of similar import. Similarly, statements that describe future financial performance or plans or strategies are forward-looking statements. Such forward-looking statements are subject to certain risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements. Some, but not all, of the risks and uncertainties of Alliant Energy, IPL and WPL that could materially affect actual results include:

- IPL's and WPL's ability to obtain adequate and timely rate relief to allow for, among other things, earning a return on rate base additions and the recovery of costs, including fuel costs, operating costs, transmission costs, environmental compliance and remediation costs, deferred expenditures, deferred tax assets, capital expenditures, and remaining costs related to EGUs that may be permanently closed, earning their authorized rates of return, and the payments to their parent of expected levels of dividends;
- federal and state regulatory or governmental actions, including the impact of energy, tax, financial and health care legislation, and regulatory agency orders;
- ability to obtain regulatory approval for wind projects with acceptable conditions, to acquire sufficient transmission-ready wind sites, to complete construction within the cost caps set by regulators and to meet all requirements to qualify for the full level of production tax credits;
- the impact of customer- and third party-owned generation, including alternative electric suppliers, in IPL's and WPL's service territories on system reliability, operating expenses and customers' demand for electricity;
- the impact of energy efficiency, franchise retention and customer disconnects on sales volumes and margins;
- the impact that price changes may have on IPL's and WPL's customers' demand for electric, gas and steam services and their ability to pay their bills;
- the impact of adjustments made to deferred tax assets and liabilities from changes in the tax laws;
- the ability to utilize tax credits and net operating losses generated to date, and those that may be generated in the future, before they expire;
- the direct or indirect effects resulting from terrorist incidents, including physical attacks and cyber attacks, or responses to such incidents;
- the impact of penalties or third-party claims related to, or in connection with, a failure to maintain the security of personally identifiable information, including associated costs to notify affected persons and to mitigate their information security concerns;
- employee workforce factors, including changes in key executives, ability to hire and retain employees with specialized skills, ability to create desired corporate culture, collective bargaining agreements and negotiations, work stoppages or restructurings;
- weather effects on results of utility operations;
- issues associated with environmental remediation and environmental compliance, including compliance with the Consent Decree between WPL, the EPA and the Sierra Club, the Consent Decree between IPL, the EPA, the Sierra Club, the State of Iowa and Linn County in Iowa, the CCR rule, the Clean Power Plan, future changes in environmental laws and regulations, including the EPA's regulations for CO2 emissions reductions from new and existing fossil-fueled EGUs, and litigation associated with environmental requirements;
- the ability to defend against environmental claims brought by state and federal agencies, such as the EPA, state natural resources agencies or third parties, such as the Sierra Club, and the impact on operating expenses of defending and resolving such claims;
- continued access to the capital markets on competitive terms and rates, and the actions of credit rating agencies;
- inflation and interest rates;
- the impact of the economy in IPL's and WPL's service territories and the resulting impacts on sales volumes, margins and the ability to collect unpaid bills;
- changes in the price of delivered natural gas, purchased electricity and coal due to shifts in supply and demand caused by market conditions and regulations;
- disruptions in the supply and delivery of natural gas, purchased electricity and coal;
- changes in the price of transmission services and the ability to recover the cost of transmission services in a timely manner;
- developments that adversely impact the ability to implement the strategic plan;
- the direct or indirect effects resulting from breakdown or failure of equipment in the operation of electric and gas distribution systems, such as mechanical problems and explosions or fires, and compliance with electric and gas transmission and distribution safety regulations;

- issues related to the availability and operations of EGUs, including start-up risks, breakdown or failure of equipment, performance below expected or contracted levels of output or efficiency, operator error, employee safety, transmission constraints, compliance with mandatory reliability standards and risks related to recovery of resulting incremental costs through rates;
- impacts that storms or natural disasters in IPL's and WPL's service territories may have on their operations and recovery of costs associated with restoration activities;
- any material post-closing adjustments related to any past asset divestitures, including the sales of IPL's Minnesota electric and natural gas assets, and Whiting Petroleum, which could result from, among other things, indemnification agreements, warranties, parental guarantees or litigation;
- Alliant Energy's ability to sustain its dividend payout ratio goal;
- changes to costs of providing benefits and related funding requirements of pension and OPEB plans due to the market value of the assets that fund the plans, economic conditions, financial market performance, interest rates, life expectancies and demographics;
- material changes in employee-related benefit and compensation costs;
- risks associated with operation and ownership of non-utility investments;
- changes in technology that alter the channels through which customers buy or utilize Alliant Energy's, IPL's or WPL's products and services;
- impacts on equity income from unconsolidated investments due to further potential changes to ATC's authorized return on equity;
- impacts of IPL's future tax benefits from Iowa rate-making practices, including deductions for repairs expenditures and allocation of mixed service costs, and recoverability of the associated regulatory assets from customers, when the differences reverse in future periods;
- changes to the creditworthiness of counterparties with which Alliant Energy, IPL and WPL have contractual arrangements, including participants in the energy markets and fuel suppliers and transporters;
- current or future litigation, regulatory investigations, proceedings or inquiries;
- reputational damage from negative publicity, protests, fines, penalties and other negative consequences resulting in regulatory and/or legal actions;
- the effect of accounting standards issued periodically by standard-setting bodies;
- the ability to successfully complete tax audits and changes in tax accounting methods with no material impact on earnings and cash flows; and
- factors listed in MDA and Item 1A Risk Factors.

Alliant Energy, IPL and WPL each assume no obligation, and disclaim any duty, to update the forward-looking statements in this report, except as required by law.

WEBSITE ACCESS TO REPORTS

Alliant Energy, IPL and WPL make their periodic and current reports, and amendments to those reports, available, free of charge, on Alliant Energy's website at www.alliantenergy.com/investors on the same day as such material is electronically filed with, or furnished to, the SEC. Alliant Energy, IPL and WPL are not including the information contained on Alliant Energy's website as a part of, or incorporating it by reference into, this report.

PART I

This report includes information relating to Alliant Energy, IPL and WPL (as well as AEF and Corporate Services). Where appropriate, information relating to a specific entity has been segregated and labeled as such. Unless otherwise noted, the information herein excludes discontinued operations for all periods presented.

ITEM 1. BUSINESS

A. GENERAL

Alliant Energy was incorporated in Wisconsin in 1981 and maintains its principal executive offices in Madison, Wisconsin. Alliant Energy operates as a regulated investor-owned public utility holding company. Alliant Energy's primary focus is to provide regulated electric and natural gas service to approximately 960,000 electric and approximately 410,000 natural gas customers in the Midwest through its two public utility subsidiaries, IPL and WPL. The primary first tier wholly-owned subsidiaries of Alliant Energy are as follows:

1) IPL - was incorporated in 1925 in Iowa as Iowa Railway and Light Corporation. IPL is a public utility engaged principally in the generation and distribution of electricity and the distribution and transportation of natural gas to retail customers in select markets in Iowa. IPL provides utility services to incorporated communities as directed by the IUB and utilizes non-exclusive franchises, which cover the use of public right-of-ways for utility facilities in incorporated communities for a maximum term of 25 years. At December 31, 2017, IPL supplied electric and natural gas service to approximately 490,000 and 220,000 retail customers, respectively, in Iowa. IPL also sells electricity to wholesale customers in Minnesota, Illinois and Iowa. IPL is also engaged in the generation and distribution of steam for two customers in Cedar Rapids, Iowa. In 2017, 2016 and 2015, IPL had no single customer for which electric, gas, steam and/or other sales accounted for 10% or more of IPL's consolidated revenues.

2) WPL - was incorporated in 1917 in Wisconsin as Eastern Wisconsin Electric Company. WPL is a public utility engaged principally in the generation and distribution of electricity and the distribution and transportation of natural gas to retail customers in select markets in Wisconsin. WPL operates in municipalities pursuant to permits of indefinite duration and state statutes authorizing utility operation in areas annexed by a municipality. At December 31, 2017, WPL supplied electric and natural gas service to approximately 470,000 and 190,000 retail customers, respectively. WPL also sells electricity to wholesale customers in Wisconsin. In 2017, 2016 and 2015, WPL had no single customer for which electric, gas and/or other sales accounted for 10% or more of WPL's consolidated revenues.

3) AEF - was created in 2016 in Wisconsin as a limited liability company. Alliant Energy's non-utility investments are organized under AEF. Refer to "Information Relating to Non-utility Operations" for additional details.

4) CORPORATE SERVICES - was incorporated in 1997 in Iowa. Corporate Services provides administrative services to Alliant Energy, IPL, WPL and AEF.

Refer to Note 17 for further discussion of business segments, which information is incorporated herein by reference.

B. INFORMATION RELATING TO ALLIANT ENERGY ON A CONSOLIDATED BASIS

1) EMPLOYEES - At December 31, 2017, Alliant Energy, IPL and WPL had the following full- and part-time employees:

	Total Number of Employees	Number of Bargaining Unit Employees	Percentage of Employees Covered by Collective Bargaining Agreements
Alliant Energy	3,989	2,222	56%
IPL	1,670	1,074	64%
WPL	1,278	1,038	81%

The majority of IPL's bargaining unit employees are covered by the International Brotherhood of Electrical Workers Local 204 (Cedar Rapids) collective bargaining agreement, which expires on August 31, 2020. All of WPL's bargaining unit employees are covered by the International Brotherhood of Electrical Workers Local 965 collective bargaining agreement, which expires on May 31, 2019.

2) CAPITAL EXPENDITURE AND INVESTMENT PLANS - Refer to "Liquidity and Capital Resources" in MDA for discussion of anticipated construction and acquisition expenditures for 2018 through 2021.

3) REGULATION - Alliant Energy, IPL and WPL are subject to regulation by various federal, state and local agencies. The following includes the primary regulations impacting Alliant Energy's, IPL's and WPL's businesses.

FERC -
Public Utility Holding Company Act of 2005 - Alliant Energy is registered with FERC as a public utility holding company, pursuant to the Public Utility Holding Company Act of 2005, and is required to maintain certain records and to report certain transactions involving its public utilities, service company and other entities regulated by FERC. Corporate Services, IPL and WPL are subject to regulation by FERC under the Public Utility Holding Company Act of 2005 for various matters including, but not limited to, affiliate transactions, public utility mergers, acquisitions and dispositions, and books, records and accounting requirements.

Energy Policy Act - The Energy Policy Act requires creation of an Electric Reliability Organization to provide oversight by FERC. FERC designated North American Electric Reliability Corporation as the overarching Electric Reliability Organization. Midwest Reliability Organization, which is a regional member of North American Electric Reliability Corporation, has direct responsibility for mandatory electric reliability standards for IPL and WPL.

Federal Power Act - FERC also has jurisdiction, under the Federal Power Act, over certain electric utility facilities and operations, electric wholesale and transmission rates, dividend payments, issuance of IPL's securities, and accounting practices of Corporate Services, IPL and WPL.

Electric Wholesale Rates - IPL and WPL receive wholesale electric market-based rate authority from FERC. Market-based rate authorization allows for wholesale sales of electricity within the MISO market and in transactions directly with third parties, based on the market value of the transactions. IPL and WPL also have FERC-approved cost of service formula based rates related to the provision of firm full- and partial-requirement wholesale electric sales, which allow for true-ups to actual costs, including fuel costs.

Electric Transmission Rates - FERC regulates the rates charged for electric transmission facilities used in interstate commerce. Neither IPL nor WPL own or operate electric transmission facilities; however, both IPL and WPL pay for the use of the interstate electric transmission system based upon FERC-regulated rates. IPL and WPL rely primarily on the use of the ITC and ATC transmission systems, respectively. Due to the formula rates used by ITC and ATC to charge their customers and possible future changes to these rates, there is uncertainty regarding IPL's and WPL's future electric transmission service expense. Refer to "Other Future Considerations" in MDA for further discussion of electric transmission service expense.

Natural Gas Act - FERC regulates the transportation and sale for resale of natural gas in interstate commerce under the Natural Gas Act. Under the Natural Gas Act, FERC has authority over certain natural gas facilities and operations of IPL and WPL.

IUB - IPL is subject to regulation by the IUB for various matters including, but not limited to, retail utility rates and standards of service, accounting requirements, sales of assets with values that exceed 3% of IPL's revenues, and approval of the location and construction of EGUs.

Retail Utility Base Rates - IPL files periodic requests with the IUB for retail rate changes, which are based on historical test periods. The historical test periods may be adjusted for certain known and measurable changes to capital investments, cost of capital and operating and maintenance expenses consistent with IUB rules and regulations. Interim retail rates can be placed in effect 10 days after the rate application filing, subject to refund, and must be based on previously established regulatory principles. The IUB must decide on requests for retail rate changes within 10 months of the date of the application for which changes are filed, or the interim rates granted become permanent.

Cost Recovery - In accordance with Iowa law, IPL is required to file an EEP every five years with the IUB. An EEP provides a utility's plan and related budget to achieve specified levels of electric and gas energy savings. IUB approval demonstrates that IPL's EEP is reasonably expected to achieve cost-effective delivery of the energy efficiency programs. IPL recovers energy efficiency costs from its retail electric and gas customers. Refer to Note 1(g) for further discussion of IPL's cost recovery mechanisms, including retail commodity costs and retail electric transmission costs.

Electric Generating Units - IPL must obtain a certificate of public convenience, use and necessity (GCU Certificate) from the IUB in order to construct a new, or significantly alter (including fuel switching) an existing, EGU located in Iowa with 25 MW or more of capacity. IPL's ownership and operation of EGUs (including those located outside the state of Iowa) to serve Iowa customers is subject to retail utility rate regulation by the IUB.

Gas Pipeline Projects - IPL must obtain a pipeline permit from the IUB related to the siting of utility gas pipelines in Iowa that will be operated at a pressure over 150 pounds per square inch and will transport gas from a gathering or storage facility to a distribution system or single, large volume customer.

Advance Rate-making Principles - Iowa law provides Iowa utilities with rate-making principles prior to making certain generation investments in Iowa. As a result, IPL may file for, and the IUB must render a decision on, rate-making principles for EGUs located in Iowa, including any new combined-cycle natural gas-fired EGU, any renewable generating resource such as a wind facility, and base-load (nuclear or coal-fired generation) EGUs with a nameplate generating capacity of 300 MW or more. Upon approval of rate-making principles by the IUB, IPL must either build the EGU under the approved rate-making principles, or not at all.

Electric Generating Unit Environmental Controls Projects - IPL is required to submit an updated EPB biennially to the IUB setting out a multi-year plan and budget for managing regulated emissions from its coal-fired EGUs in a cost-effective manner. IPL must simultaneously submit this plan and budget to the Iowa Department of Natural Resources for a determination of whether the plan and budget meet state environmental requirements for regulated emissions. The reasonable and prudent costs associated with implementing the approved plan are expected to be included in IPL's future retail electric rates.

PSCW - Alliant Energy is subject to regulation by the PSCW for the type and amount of Alliant Energy's investments in non-utility businesses and other affiliated interest activities, among other matters. WPL is also subject to regulation by the PSCW related to its operations in Wisconsin for various matters including, but not limited to, retail utility rates and standards of service, accounting requirements, issuance and use of proceeds of securities, affiliate transactions, approval of the location and construction of EGUs and certain other additions and extensions to facilities.

Retail Utility Base Rates - WPL files periodic requests with the PSCW for retail rate changes. These filings are required to be based on forward-looking test periods. There is no statutory time limit for the PSCW to decide retail base rate requests. However, the PSCW attempts to process retail base rate reviews in approximately 10 months and has the ability to approve interim retail rate relief, subject to refund, if necessary. Currently, WPL is required to defer a portion of its earnings if its annual regulatory return on common equity exceeds certain levels.

Cost Recovery - WPL contributes 1.2% of its annual retail utility revenues to help fund Focus on Energy, Wisconsin's state-wide energy efficiency and renewable energy resource program. These costs are recovered from WPL's retail electric and gas customers. Refer to Note 1(g) for further discussion of WPL's cost recovery mechanisms, including retail commodity costs and retail electric transmission costs.

New Electric Generating Units - A CA application is required to be filed with the PSCW for construction approval of any new EGU with a capacity of less than 100 MW and a project cost of $10.7 million or more. WPL must obtain a CPCN from the PSCW in order to construct a new EGU in Wisconsin with a capacity of 100 MW or more. In addition, WPL's ownership and operation of EGUs (including those located outside the state of Wisconsin) to serve Wisconsin customers are subject to retail utility rate regulation by the PSCW.

Electric Generating Unit Upgrades and Electric Distribution Projects - A CA application is required to be filed with the PSCW for construction approval of any additions to EGUs, including environmental controls projects, as well as electric distribution projects, with estimated project costs of $10.7 million or more.

Gas Distribution Projects - A CA application is required to be filed with the PSCW for construction approval of gas projects with an estimated project cost of $2.5 million or more and at any time that WPL requests to extend gas service to a new portion of its service territory.

Advance Rate-making Principles - Wisconsin law provides Wisconsin utilities with the opportunity to request rate-making principles prior to the purchase or construction of any EGU utilized to serve Wisconsin customers. WPL is not obligated to file for or accept authorized rate-making principles under Wisconsin law. WPL can proceed with an approved project under traditional rate-making terms or accept authorized rate-making principles under Wisconsin law.

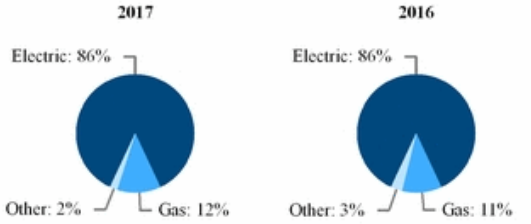
Environmental - Extensive environmental laws and regulations are applicable as a result of current and past operations. The environmental laws and regulations relate to the protection of the environment and health and safety matters, including those governing air emissions; water discharges; protection of habitat for potentially threatened and endangered species; the management, storage and disposal of hazardous materials; and the clean-up of contaminated sites, including former MGP sites. Refer to "Environmental Matters" in MDA and Note 16(e) for further discussion of electric and gas environmental matters, including current or proposed environmental regulations. Refer to "Strategic Overview" in MDA for details of future environmental compliance plans to adhere to applicable environmental requirements.

4) STRATEGIC OVERVIEW - Refer to "Strategic Overview" in MDA for discussion of various strategic actions by Alliant Energy, IPL and WPL.

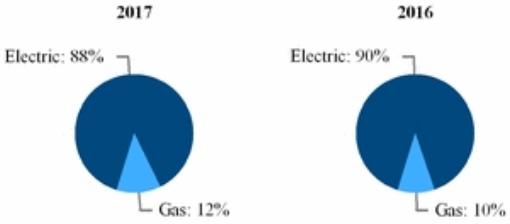
C. INFORMATION RELATING TO UTILITY OPERATIONS

Alliant Energy's utility business (IPL and WPL) has three segments: a) electric operations; b) gas operations; and c) other, which includes IPL's steam operations and the unallocated portions of the utility business. IPL's and WPL's operating revenues as a percentage of total revenues for these utility business segments were as follows:

IPL



WPL



1) ELECTRIC UTILITY OPERATIONS

General - Electric utility operations represent the largest operating segment for Alliant Energy, IPL and WPL. Alliant Energy's electric utility operations are located in the Midwest with IPL providing retail electric service in Iowa and WPL providing retail and wholesale electric service in Wisconsin. IPL also sells electricity to wholesale customers in Minnesota, Illinois and Iowa. Refer to the "Electric Operating Information" tables for additional details regarding electric utility operations.

Customers - IPL and WPL provide electric utility service to a diversified base of retail customers in several industries, with the largest concentrations in the farming, agriculture, industrial manufacturing, chemical (including ethanol) and paper industries. IPL and WPL also sell electricity to wholesale customers, which primarily consist of municipalities and rural electric cooperatives. Refer to "Strategic Overview" in MDA for discussion of recent agreements with certain of WPL's electric wholesale customers related to WPL's West Riverside facility. Refer to "Other Future Considerations" in MDA for discussion of notifications provided to each of IPL and WPL to terminate certain of their wholesale power supply agreements.

Seasonality - Electric sales are seasonal to some extent with the annual peak normally occurring in the summer months due to air conditioning requirements. Electric sales are also impacted to a certain extent in the winter months due to heating requirements. Refer to the "Electric Operating Information" tables for additional details regarding maximum summer and winter peak hour demands.

Competition - Retail electric customers in Iowa and Wisconsin currently do not have the ability to choose their electric supplier, and IPL and WPL have obligations to serve all their retail electric customers. Although electric service in Iowa and Wisconsin is regulated, IPL and WPL still face competition from self-generation by large industrial customers, customer- and third party-owned generation (e.g. solar panels), alternative energy sources, and petitions to municipalize (Iowa) as well as service territory expansions by municipal utilities through annexations (Wisconsin). In addition, IPL's and WPL's wholesale customers may choose to purchase their electric energy and capacity needs from the MISO market, independent power producers or other utilities. Alliant Energy's strategic plan includes actions to retain current customers and attract new customers into IPL's and WPL's service territories in an effort to keep energy rates low for all of their customers. Refer to "Strategic Overview" in MDA for discussion of the growth element of the strategic plan, which includes accelerating the growth of customers' electric usage.

Renewable Energy Standards - Iowa and Wisconsin have RES, which establish the minimum amount of energy IPL and WPL must supply from renewable resources. IPL primarily relies upon renewable energy generated from the wind projects it owns and renewable energy acquired under PPAs to meet these requirements. WPL utilizes its current renewable portfolio, which primarily consists of wind and hydro energy, both owned and acquired under PPAs, to meet these requirements. IPL and WPL currently exceed their respective RES requirements.

Energy Efficiency Programs - Several energy efficiency programs and initiatives help customers reduce their energy usage and related costs through the use of new energy efficient equipment, products and practices. The following are current key energy efficiency programs:

IPL Energy Efficiency Plan - In 2013, IPL received an order from the IUB approving IPL's EEP for 2014 through 2018. The EEP includes IPL spending approximately $400 million for electric and natural gas energy efficiency programs in Iowa from 2014 through 2018. In February 2018, IPL filed an EEP for 2019 through 2023 with the IUB. This EEP includes IPL spending approximately $290 million for electric and natural gas energy efficiency programs in Iowa from 2019 through 2023. The amount of spending requested for the EEP for 2019 through 2023 is lower than the EEP for 2014 through 2018 primarily to reflect historical customer usage of the energy efficiency programs. A decision from the IUB on IPL's EEP for 2019 through 2023 is currently expected in 2018.

WPL Focus on Energy Program - In 2017, WPL contributed 1.2% of its annual retail utility revenues to help fund Focus on Energy, Wisconsin's state-wide energy efficiency and renewable energy resource program.

Electric Supply - Alliant Energy, IPL and WPL have met, and expect to continue meeting, customer demand of electricity through a mix of electric supply including owned EGUs, PPAs and additional purchases from wholesale energy markets. Alliant Energy expects its mix of electric supply to change in the next several years with WPL's construction of West Riverside, IPL's planned up to 1,000 MW of additional wind generation, WPL's planned up to 200 MW of additional wind generation and the proposed retirement and/or fuel switching of various EGUs. Long-term generation plans are intended to meet customer demand, reduce CO2 emissions, reduce reliance on wholesale market purchases and mitigate the impacts of future EGU retirements while maintaining compliance with long-term electric demand planning reserve margins, environmental requirements and RES established by regulators. Alliant Energy, IPL and WPL currently expect to meet utility customer demand in the future. However, unanticipated regional or local reliability issues could still arise in the event of outages or unexpected delays in the construction of new generating and/or transmission facilities, EGU retirements, EGU outages, transmission system outages or extended periods of extreme weather conditions. Refer to the "Electric Operating Information" tables for a profile of the sources of electric supply used to meet customer demand from 2015 to 2017. Refer to "Strategic Overview" in MDA for details of recent changes in the mix of electric supply, as well as future generation plans.

Electric Demand Planning Reserve Margin - IPL and WPL are required to maintain a planning reserve margin above their load at the time of the MISO-wide peak to ensure reliability of electric service to their customers. The required installed capacity reserve margin is 17.1% and the required unforced capacity reserve margin is 8.4% for the June 1, 2018 through May 31, 2019 MISO planning year. IPL and WPL currently have adequate capacity to meet such MISO planning reserve margin requirements.

Generation - IPL and WPL own a portfolio of EGUs located in Iowa, Wisconsin and Minnesota with a diversified fuel mix that includes natural gas, renewable resources and coal. Refer to "Properties" in Item 2 for details of IPL's and WPL's EGUs.

Fuel Costs - The average cost of delivered fuel per million British Thermal Units used for electric generation was as follows:

	IPL			WPL		
	2017	2016	2015	**2017**	2016	2015
All fuels	**$2.22**	$2.17	$2.21	**$2.53**	$2.61	$2.67
Natural gas (a)	**2.72**	2.86	3.37	**3.28**	3.25	3.68
Coal	**2.00**	1.98	1.94	**2.38**	2.47	2.49

(a) The average cost of natural gas includes commodity and transportation costs, as well as realized gains and losses from swap and option contracts used to hedge the price of natural gas volumes expected to be used by IPL's and WPL's natural gas-fired EGUs.

Natural Gas - Alliant Energy, IPL and WPL own several natural gas-fired EGUs, and WPL also has exclusive rights to the output of AEF's Sheboygan Falls Energy Facility under an affiliated lease agreement. These facilities help meet customer demand for electricity generally during peak hour demands and when natural gas prices are low enough to make natural gas-fired generation economical compared to other fuel sources. Alliant Energy manages the gas supply to these gas-fired EGUs and helps ensure an adequate supply is available at known prices through a combination of gas commodity, pipeline transportation and storage agreements held by IPL and WPL for 2018 through 2034. Alliant Energy, IPL and WPL believe they are reasonably insulated against gas price volatility for these EGUs given their use of forward contracts and hedging practices, as well as their regulatory cost-recovery mechanisms.

Wind - IPL owns the Whispering Willow - East and Franklin County wind farms, and WPL owns the Cedar Ridge and Bent Tree wind farms. All or some of the renewable energy attributes associated with generation from these sources may be used in future years to comply with RES or other regulatory requirements, or sold to third parties in the form of renewable energy credits or other environmental commodities.

Coal - Coal is one of the fuel sources for owned EGUs. Coal contracts entered into with different suppliers help ensure that a specified supply of coal is available, and delivered, at known prices for IPL's and WPL's coal-fired EGUs for 2018 through 2020. Alliant Energy, IPL and WPL believe their coal supply portfolio represents a reasonable balance between the risks of insufficient supplies and those associated with being unable to respond to future coal market changes. Remaining coal requirements are expected to be met from either future term contracts or purchases in the spot market. Nearly all of the coal utilized by IPL and WPL is from the Wyoming Powder River Basin.

Alliant Energy, IPL and WPL believe they are reasonably insulated against coal price volatility given their current coal procurement process, the specific coal market in their primary purchase region and regulatory cost-recovery mechanisms. The coal procurement process supports periodic purchases, staggering of contract terms, stair-stepped levels of supply going forward and supplier diversity. Similarly, given the term lengths of their transportation agreements and strategic alignment of agreement expirations for negotiation purposes, Alliant Energy, IPL and WPL believe they are reasonably insulated against future higher coal transportation rates from the major railroads.

Purchased Power - IPL and WPL periodically enter into PPAs and purchase electricity from wholesale energy markets to meet a portion of their customer demand for electricity. IPL's most significant PPA is for the purchase of up to 431 MWs of capacity and the resulting energy from DAEC for a term from February 2014 through December 2025. WPL's most significant PPA is for the purchase of 150 MWs of energy for a term from January 2014 through December 2018.

IPL's DAEC PPA - In 2013, the IUB issued an order allowing IPL to proceed with a PPA for the purchase of capacity and energy generated by DAEC located near Palo, Iowa. The IUB also authorized IPL to recover the Iowa retail portion of the cost of the DAEC PPA from Iowa retail electric customers through the energy adjustment clause. The terms of the PPA provide IPL the right to the counterparty's entire output quantities (70% of the total plant output) in exchange for payment from IPL to the counterparty based on the amount of MWhs received by IPL. Among the terms and conditions of the PPA are guarantees by the counterparty to provide minimum amounts of capacity and energy. The PPA also contains provisions for the replacement of energy from alternative sources under certain conditions as well as provisions that convey to IPL the potential environmental attributes associated with its portion of the output from DAEC.

Electric Transmission - IPL and WPL do not own electric transmission assets and currently receive substantially all their electric transmission services from ITC and ATC, respectively. ITC and ATC are independent, for-profit, transmission-only companies and are transmission-owning members of the MISO Regional Transmission Organization, Midwest Reliability Organization and Reliability First Corporation Regional Entities. The annual transmission service rates that ITC or ATC charges their customers are calculated each calendar year using a FERC-approved cost of service formula rate. As a result, ITC and ATC can implement new rates each calendar year without filing a request with FERC. However, new rates are subject to challenge by either FERC or customers. If the rates proposed by ITC or ATC are determined by FERC to be unjust or unreasonable, or another mechanism is determined by FERC to be just and reasonable, ITC's or ATC's rates would change accordingly.

Refer to Note 1(g) for discussion of a transmission cost rider utilized by IPL for recovery of its electric transmission service expense, and discussion of WPL's electric transmission service expense, which is recovered from its retail electric customers through changes in base rates determined during periodic rate proceedings. Refer to Note 18 for details of agreements between ATC and WPL.

MISO Markets - IPL and WPL are members of MISO, a FERC-approved Regional Transmission Organization, which is responsible for monitoring and ensuring equal access to the transmission system in their footprint. IPL and WPL participate in the wholesale energy and ancillary services markets operated by MISO, which are discussed in more detail below. As agent for IPL and WPL, Corporate Services enters into energy, capacity, ancillary services, and transmission sale and purchase transactions within MISO. Corporate Services assigns such sales and purchases between IPL and WPL based on statements received from MISO. Refer to Note 18 for additional discussion of these assigned amounts.

Wholesale Energy Market - IPL and WPL sell and purchase power in the day-ahead and real-time wholesale energy markets operated by MISO. MISO's bid-based markets compare the cost of IPL and WPL generation against other generators, which affects IPL and WPL generation operations, energy purchases and energy sales. MISO generally dispatches the lowest cost generators, while recognizing current system constraints, to reduce costs for purchasers in the wholesale energy market. In addition, MISO may dispatch generators that support reliability needs, but that would not have operated based on economic needs. In these cases, MISO's settlement assures that these generators are made whole financially for their variable costs.

Ancillary Services Market - IPL and WPL also participate in MISO's ancillary services market, which integrates the procurement and use of regulation and contingency reserves with the existing wholesale energy market to ensure reliability of electricity supply. Regulation reserves refer to generation available to meet the moment-to-moment changes in generation that are necessary to meet changes in electricity demand. Contingency reserves refer to additional generation or demand response resources, either on-line or that can be brought on-line within 10 minutes, to meet certain major events such as the loss of a large EGU or transmission line. MISO's ancillary services market has had the overall impact of lowering ancillary services costs in the MISO footprint.

Financial Transmission Rights and Auction Revenue Rights - In areas of constrained transmission capacity, energy costs could be higher due to congestion and its impact on locational marginal prices. FTRs provide a hedge for certain congestion costs that occur in the MISO energy market. MISO allocates auction revenue rights to IPL and WPL annually based on a fiscal year from June 1 through May 31 and historical use of the transmission system. The allocated auction revenue rights are used by IPL and WPL to acquire FTRs through the FTR auctions operated by MISO.

Resource Adequacy - MISO conducts various studies regarding reliability of electric service to ensure its market participants have adequate resources to meet MISO's forecasted peak load obligations plus a reserve margin. Only accredited capacity assigned to EGUs is available to meet these requirements. To connect to the transmission system, MISO requires an EGU to obtain an interconnection agreement. In order for an EGU to receive accredited capacity, it must meet MISO capacity accreditation requirements, which can include satisfying transmission requirements identified in its interconnection agreement prior to the MISO planning year. New EGUs like West Riverside, or IPL's and WPL's planned additional wind generation, may not initially receive full accredited capacity based on the inability to satisfy all identified transmission requirements. Therefore, full accredited capacity may not be granted to such EGUs until all identified transmission requirements are resolved.

Electric Environmental Matters - Refer to Note 16(e) and "Environmental Matters" in MDA for discussion of electric environmental matters, including current or proposed environmental regulations.

Electric Operating Information - Alliant Energy	2017	2016	2015
Operating Revenues (in millions):			
Retail	**$2,569.6**	$2,564.8	$2,474.1
Sales for resale	**268.8**	266.7	249.5
Other	**56.3**	44.0	46.9
Total	**$2,894.7**	$2,875.5	$2,770.5
Electric Sales (000s MWh):			
Retail	**25,095**	25,339	25,380
Sales for resale	**5,003**	4,399	4,842
Other	**94**	100	129
Total	**30,192**	29,838	30,351
Customers (End of Period):			
Retail	**959,295**	955,533	950,048
Other	**2,826**	2,785	2,930
Total	**962,121**	958,318	952,978
Other Selected Electric Data:			
Maximum summer peak hour demand (MW)	**5,375**	5,615	5,385
Maximum winter peak hour demand (MW)	**4,504**	4,559	4,668
Cooling degree days (a):			
Cedar Rapids, Iowa (IPL) (normal - 748)	**747**	971	732
Madison, Wisconsin (WPL) (normal - 646)	**578**	780	665
Sources of electric energy (000s MWh):			
Gas	**5,315**	4,505	4,738
Purchased power:			
Nuclear	**3,727**	3,444	3,741
Wind (b)	**1,268**	1,079	1,190
Other (b)	**6,242**	8,912	6,675
Wind (b)	**1,591**	1,382	1,441
Coal	**12,380**	11,019	13,040
Other (b)	**239**	228	189
Total	**30,762**	30,569	31,014
Revenue per KWh sold to retail customers (cents)	**10.24**	10.12	9.75

(a) Cooling degree days are calculated using a simple average of the high and low temperatures each day compared to a 65 degree base. Normal degree days are calculated using a rolling 20-year average of historical cooling degree days. Refer to "Gas Utility Operations" below for details of heating degree days.

(b) All or some of the renewable energy attributes associated with generation from these sources may be used in future years to comply with renewable energy standards or other regulatory requirements, or sold to third parties in the form of renewable energy credits or other environmental commodities.

Electric Operating Information	IPL			WPL		
	2017	2016	2015	**2017**	2016	2015
Operating Revenues (in millions):						
Retail	**$1,448.0**	$1,442.5	$1,410.2	**$1,121.6**	$1,122.3	$1,063.9
Sales for resale	**114.6**	97.8	61.5	**154.2**	168.9	188.0
Other	**36.3**	29.4	32.1	**20.0**	14.6	14.8
Total	**$1,598.9**	$1,569.7	$1,503.8	**$1,295.8**	$1,305.8	$1,266.7
Electric Sales (000s MWh):						
Retail	**14,356**	14,523	14,824	**10,739**	10,816	10,556
Sales for resale	**2,169**	1,406	1,023	**2,834**	2,993	3,819
Other	**38**	41	67	**56**	59	62
Total	**16,563**	15,970	15,914	**13,629**	13,868	14,437
Customers (End of Period):						
Retail	**489,717**	489,005	488,582	**469,578**	466,528	461,466
Other	**878**	862	1,050	**1,948**	1,923	1,880
Total	**490,595**	489,867	489,632	**471,526**	468,451	463,346
Other Selected Electric Data:						
Maximum summer peak hour demand (MW)	**2,968**	2,996	3,005	**2,476**	2,681	2,564
Maximum winter peak hour demand (MW)	**2,421**	2,479	2,531	**2,100**	2,131	2,153
Cooling degree days (a):						
Cedar Rapids, Iowa (IPL) (normal - 748)	**747**	971	732	**N/A**	N/A	N/A
Madison, Wisconsin (WPL) (normal - 646)	**N/A**	N/A	N/A	**578**	780	665
Sources of electric energy (000s MWh):						
Gas	**3,342**	1,838	1,874	**1,973**	2,667	2,864
Purchased power:						
Nuclear	**3,727**	3,444	3,741	**N/A**	N/A	N/A
Wind (b)	**613**	635	757	**655**	444	433
Other (b)	**2,456**	4,267	3,015	**3,786**	4,645	3,660
Wind (b)	**851**	630	653	**740**	752	788
Coal	**5,766**	5,598	6,263	**6,614**	5,421	6,777
Other (b)	**22**	6	5	**217**	222	184
Total	**16,777**	16,418	16,308	**13,985**	14,151	14,706
Revenue per KWh sold to retail customers (cents)	**10.09**	9.93	9.51	**10.44**	10.38	10.08

(a) Cooling degree days are calculated using a simple average of the high and low temperatures each day compared to a 65 degree base. Normal degree days are calculated using a rolling 20-year average of historical cooling degree days. Refer to "Gas Utility Operations" below for details of heating degree days.

(b) All or some of the renewable energy attributes associated with generation from these sources may be used in future years to comply with renewable energy standards or other regulatory requirements, or sold to third parties in the form of renewable energy credits or other environmental commodities.

2) GAS UTILITY OPERATIONS

General - Gas utility operations represent the second largest operating segment for Alliant Energy, IPL and WPL. Alliant Energy's gas utility operations are located in the Midwest with IPL providing gas service in Iowa and WPL providing gas service in Wisconsin. Refer to the "Gas Operating Information" tables for additional details regarding gas utility operations. Refer to Note 1(g) for information relating to utility natural gas cost recovery mechanisms and Note 16(b) for discussion of natural gas commitments.

Customers - IPL and WPL provide gas utility service to a diversified base of retail customers and industries, including research, education, hospitality, manufacturing and chemicals (including ethanol). In addition, IPL and WPL provide transportation service to commercial and industrial customers by moving customer-owned gas through Alliant Energy's distribution systems to the customers' meters.

Seasonality - Gas sales follow a seasonal pattern with an annual base-load of gas and a large heating peak occurring during the winter season. Natural gas obtained from producers, marketers and brokers, as well as gas in storage, is utilized to meet the peak heating season requirements. Storage contracts generally allow IPL and WPL to purchase gas in the summer and inject it into underground storage fields, and remove it from storage fields in the winter to deliver to customers. Refer to the "Gas Operating Information" tables for details regarding maximum daily winter peak demands.

Competition - Gas customers in Iowa and Wisconsin currently do not have the ability to choose their gas distributor, and IPL and WPL have obligations to serve all their gas customers. While the gas utility distribution function is expected to remain a regulated function, sales of the natural gas commodity and related services are subject to competition from third-parties who provide alternative fuel sources (e.g. propane). However, when natural gas service is available for a given area, customers in such area have generally selected natural gas over propane as a more cost competitive solution for their fuel needs. Refer to "Strategic Overview" in MDA for discussion of plans to extend gas distribution systems, as well as discussion of the growth element of Alliant Energy's strategic plan.

Gas Supply - IPL and WPL maintain purchase agreements with over 70 suppliers of natural gas from various gas producing regions of the U.S. and Canada. In providing gas commodity service to retail customers, Corporate Services administers a diversified portfolio of transportation and storage contracts on behalf of IPL and WPL. The tariffs for IPL's and WPL's retail gas customers provide for subsequent adjustments to their rates for the cost of gas sold to these customers. As a result, natural gas prices do not have a material impact on IPL's or WPL's gas margins.

Gas Demand Planning Reserve Margin - IPL and WPL are required to maintain adequate pipeline capacity to ensure they meet their customers' maximum daily system demand requirements. IPL and WPL currently have planning reserve margins of 3% and 2%, respectively, above their forecasted maximum daily system demand requirements from November 2017 through March 2018.

Gas Environmental Matters - Refer to Note 16(e) and "Environmental Matters" in MDA for discussion of gas environmental matters.

Gas Operating Information - Alliant Energy	2017	2016	2015
Operating Revenues (in millions):			
Retail	**$364.6**	$322.4	$349.9
Transportation/other	**36.3**	33.0	31.3
Total	**$400.9**	$355.4	$381.2
Gas Sales (000s Dths):			
Retail	**49,250**	47,743	48,635
Transportation/other	**76,916**	77,485	74,162
Total	**126,166**	125,228	122,797
Retail Customers at End of Period	**413,054**	411,758	409,405
Other Selected Gas Data:			
Heating degree days (a):			
Cedar Rapids, Iowa (IPL) (normal - 6,769)	**6,076**	5,933	6,300
Madison, Wisconsin (WPL) (normal - 7,043)	**6,569**	6,420	6,667
Revenue per Dth sold to retail customers	**$7.40**	$6.75	$7.19
Purchased gas costs per Dth sold to retail customers	**$4.23**	$3.99	$4.40

Gas Operating Information	IPL			WPL		
	2017	2016	2015	2017	2016	2015
Operating Revenues (in millions):						
Retail	**$202.2**	$183.1	$198.4	**$162.4**	$139.3	$151.5
Transportation/other	**23.8**	20.9	18.9	**12.5**	12.1	12.4
Total	**$226.0**	$204.0	$217.3	**$174.9**	$151.4	$163.9
Gas Sales (000s Dths):						
Retail	**26,580**	26,230	26,877	**22,670**	21,513	21,758
Transportation/other	**39,365**	37,158	34,129	**37,551**	40,327	40,033
Total	**65,945**	63,388	61,006	**60,221**	61,840	61,791
Retail Customers at End of Period	**224,041**	224,420	224,914	**189,013**	187,338	184,491
Other Selected Gas Data:						
Maximum daily winter peak demand (Dth)	**237,203**	262,409	267,314	**201,947**	203,655	209,289
Heating degree days (a):						
Cedar Rapids, Iowa (IPL) (normal - 6,769)	**6,076**	5,933	6,300	**N/A**	N/A	N/A
Madison, Wisconsin (WPL) (normal - 7,043)	**N/A**	N/A	N/A	**6,569**	6,420	6,667
Revenue per Dth sold to retail customers	**$7.61**	$6.98	$7.38	**$7.16**	$6.48	$6.96
Purchased gas cost per Dth sold to retail customers	**$4.34**	$4.21	$4.53	**$4.11**	$3.72	$4.25

(a) Heating degree days are calculated using a simple average of the high and low temperatures each day compared to a 65 degree base. Normal degree days are calculated using a rolling 20-year average of historical heating degree days.

3) OTHER UTILITY OPERATIONS - STEAM - IPL's Prairie Creek facility is the primary source of steam for IPL's two high-pressure steam customers. These customers are each under contract through 2025 for minimum quantities of annual steam usage, with certain conditions.

D. INFORMATION RELATING TO NON-UTILITY OPERATIONS

AEF manages a portfolio of wholly-owned subsidiaries and additional investments through the following distinct platforms:

ATI - currently holds all of Alliant Energy's ATC Investment. ATC is an independent, for-profit, transmission-only company. Refer to Note 6(a) for discussion of DATC, joint venture between Duke Energy Corporation and ATC, which is expected to acquire, build, own and operate new electric transmission infrastructure in North America.

Non-utility Wind Investment - includes a 50% cash equity ownership interest in a 225 MW non-utility wind farm located in Oklahoma.

Sheboygan Falls Energy Facility - is a 347 MW, simple-cycle, natural gas-fired EGU near Sheboygan Falls, Wisconsin, which is leased to WPL for an initial period of 20 years ending in 2025.

Transportation - includes a short-line railway that provides freight service between Cedar Rapids, Iowa and Iowa City, Iowa; a barge terminal and hauling services on the Mississippi River; and other transfer and storage services.

ITEM 1A. RISK FACTORS

You should carefully consider each of the risks described below relating to Alliant Energy, IPL and WPL, together with all of the other information contained in this combined report, before making an investment decision with respect to our securities. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially and adversely affected and you may lose all or part of your investment.

Our utility business is significantly impacted by government legislation, regulation and oversight - Our utility financial condition is influenced by how regulatory authorities, including the IUB, the PSCW and FERC, establish the rates we can charge our customers, our authorized rates of return and common equity levels, and the amount of costs that may be recovered from customers. Our ability to timely obtain rate adjustments to earn authorized rates of return depends upon timely regulatory action under applicable statutes and regulations, and cannot be guaranteed. In future rate reviews, IPL and WPL may not receive an adequate amount of rate relief to recover all costs and earn their authorized rates of return, rates may be reduced, rate refunds may be required, rate adjustments may not be approved on a timely basis, costs may not be otherwise recovered through rates, future rates may be temporarily frozen, and authorized rates of return on capital may be reduced. As a result, we may experience adverse impacts on our financial condition and results of operations.

In addition, our operations are subject to extensive regulation primarily by the IUB, the PSCW and FERC. We are also subject to oversight and monitoring by organizations such as the North American Electric Reliability Corporation, the Pipeline and Hazardous Materials Safety Administration, and the Midcontinent Independent System Operator, Inc. The impacts on our operations include: our ability to site and construct new generating facilities and recover associated costs, such as renewable energy projects; the installation of environmental controls and the recovery of associated costs; our ability to decommission generating facilities and recover related costs and the remaining carrying value of these facilities; our ability to site, construct and recover costs for new natural gas pipelines; our ability to recover costs to upgrade our electric and gas distribution systems; the amount of certain sources of energy we must use, such as renewable sources; our ability to purchase generating facilities and recover the costs associated therewith; our ability to sell utility assets and any conditions placed upon the sale of such assets; the rates paid to transmission operators and how those costs are recovered from customers; our ability to enter into purchased power agreements and recover the costs associated therewith; resource adequacy requirements, energy capacity standards, what forms of energy are considered when determining whether we meet those standards, and when new facilities such as IPL's Marshalltown Generating Station, WPL's West Riverside Energy Center, and IPL's and WPL's planned additional wind generation may be fully accredited with energy capacity; the allocation of expenditures by transmission companies on transmission network upgrades and our ability to recover costs associated therewith; reliability; safety; the issuance of securities; accounting matters; and transactions between affiliates. These regulatory authorities and organizations are also empowered to impose financial penalties and other sanctions, including requirements to implement new compliance programs. Failure to obtain approvals for any of these matters in a timely manner, or receipt of approvals with uneconomical conditions, may cause us not to pursue the construction of such projects or to record an impairment of our assets and may have a material adverse impact on our financial condition and results of operations.

Provisions of the Wisconsin Utility Holding Company Act limit our ability to invest in or grow our non-utility activities and may deter potential purchasers who might be willing to pay a premium for our stock.

Our strategic plan includes large construction projects, which are subject to risks - Our strategic plan includes constructing renewable generating facilities, constructing a natural gas-fired generating facility, making other large-scale improvements to generating facilities, and large-scale additions and upgrades to our electric and gas distribution systems. These construction projects are subject to various risks. These risks include: the inability to obtain necessary permits in a timely manner; adverse interpretation or enforcement of permit conditions; changes in applicable laws or regulations; changes in costs of materials, equipment, commodities, fuel or labor; delays caused by construction accidents or injuries; shortages in materials, equipment and qualified labor; changes to the scope or timing of the projects; general contractors or subcontractors not performing as required under their contracts; the inability to agree to contract terms or disputes in contract terms; poor initial cost estimates; work stoppages; adverse weather conditions; government actions; legal action; unforeseen engineering or technology issues; limited access to capital; and other adverse economic conditions. We may not be able to recover all costs for the projects in rates and face increased risk of potential impairment of our project investment if a construction project is not completed or is delayed, or final costs exceed expectations or the costs approved by our regulators, for example, if IPL's expansion of wind generation exceeds the respective cost cap approved by the IUB. Inability to recover costs, or inability to complete the project in a timely manner, could adversely impact our financial condition and results of operations.

Demand for energy may decrease - Our results of operations are affected by the demand for energy in our service territories. Energy demand may decrease due to many things, including economic conditions, proliferation of customer- and third party-owned generation, loss of service territory or franchises, energy efficiency measures, technological advances that increase energy efficiency, and loss of wholesale customers. The loss of sales due to lower demand for energy may increase our rates for remaining customers, as our rates must cover our fixed costs. Rate increases may cause decreased demand for energy as customers move to customer- and third party-owned generation and implement energy efficiency measures to reduce costs. The loss of customers, the inability to replace those customers with new customers, and the decrease in demand for energy could negatively impact our financial condition and results of operations.

Changes to certain tax elections, tax regulations and future taxable income could negatively impact our financial condition and results of operations - We have significantly reduced our federal and state income tax obligations over the past few years through tax planning strategies and the extension of bonus depreciation deductions for certain expenditures for property. These tax planning strategies and extensions of bonus depreciation deductions have generated large annual taxable losses and tax credits over the past few years that have resulted in significant federal net operating losses and tax credit carryforwards. We plan to utilize substantially all of these net operating losses and tax credit carryforwards in the future to reduce our income tax obligations. If we cannot generate enough taxable income in the future to utilize all of the net operating losses and tax credit carryforwards before they expire due to lower than expected financial performance or changes to tax regulations, we may incur material charges to earnings. If the IRS does not agree with the deductions resulting from our tax planning strategies or our position on the qualification of production tax credits from planned and potential wind generating facilities, our financial condition and results of operations may be adversely impacted.

Our utility business currently operates wind generating facilities, which generate production tax credits for us to use to reduce our federal tax obligations. The amount of production tax credits we earn is dependent on the level of electricity output generated by our wind farms and the applicable tax credit rate. A variety of operating and economic parameters, including significant transmission constraints, adverse weather conditions and breakdown or failure of equipment, could significantly reduce the production tax credits generated by our wind farms resulting in a material adverse impact on our financial condition and results of operations.

Also, if corporate tax rates or policies are changed with future federal or state legislation, we may be required to take material charges against earnings. For example, Tax Reform was enacted in December 2017, which included changes in corporate tax rates and tax policies. Tax Reform may result in changes in cash flows, which may have a negative impact on our credit ratings. There may also be further changes or amendments to Tax Reform or state tax policies and we are currently unable to determine what impacts any future changes will have on our financial condition or results of operations, including related impacts to IPL's and WPL's retail and wholesale electric and gas rates charged to their customers.

Finally, FERC regulates utility income tax policies, including partnership tax policies, which impact our investment in American Transmission Company LLC and ATC Holdco LLC (ATC Investment). FERC is currently investigating these income tax policies in addition to rate of return policies as a result of a court decision. The results of this investigation may lead to changes in FERC's income tax policies, which would impact partnership entities, particularly our ATC Investment. We are currently unable to determine what impacts these potential changes will have on our financial condition or results of operations, however, it is possible that a change could reduce Alliant Energy's equity earnings and distributions from its ATC Investment.

A cyber attack may disrupt our operations or lead to a loss or misuse of confidential and proprietary information or potential liability - We operate in an industry that requires the continuous use and operation of sophisticated information technology systems and network infrastructure. Cyber attacks targeting our electronic control systems used at our generating facilities and for electric and gas distribution systems could result in a full or partial disruption of our electric and/or gas operations. Any disruption of these operations could result in a loss of service to customers and a significant decrease in revenues, as well as significant expense to repair system damage and remedy security breaches. We have instituted certain safeguards to protect our operating systems and information technology assets, but they may not always be effective due to the evolving nature of cyber attacks and cyber security. We cannot guarantee that such protections will be completely successful in the event of a cyber attack. If the technology systems were to fail or be breached by a cyber attack or a computer virus, and not be recovered in a timely fashion, we may be unable to fulfill critical business functions and confidential data could be compromised, adversely impacting our financial condition and results of operation.

In addition, we may collect and retain sensitive information, including personal information about our customers, shareowners and employees. In some cases, we outsource administration of certain functions to vendors that could be targets of cyber attacks. For example, we outsource administration of our employee health insurance to Anthem. Anthem was the target of a cyber attack in 2014. Any theft, loss and/or fraudulent use of customer, shareowner, employee or proprietary data as a result of a cyber attack could subject us to significant litigation, liability and costs, as well as adversely impact our reputation with customers and regulators, among others.

We are subject to employee workforce factors that could affect our businesses - We operate in an industry that requires specialized technical skills. It may be difficult to hire and retain such a skilled workforce due to labor market conditions, the length of time needed to acquire the skills, and general competition for talent. Further, we need a workforce that is innovative, customer-focused and competitive to thrive in the future. To the extent our corporate culture does not support and develop these attributes, we may not be able to successfully implement our future plans. We are also subject to collective bargaining agreements with approximately 2,200 employees. Any work stoppage experienced in connection with negotiations of collective bargaining agreements could adversely affect our financial condition and results of operations as well as our ability to implement our strategic plan.

Our utility business is seasonal and may be adversely affected by the impacts of weather - Electric and gas utility businesses are seasonal businesses. Demand for electricity is greater in the summer months associated with higher air conditioning needs. In addition, market prices for electricity generally peak in the summer due to the higher demand. Conversely, demand for natural gas depends significantly upon temperature patterns in winter months due to heavy use in residential and commercial heating. As a result, our overall operating results in the future may fluctuate substantially on a seasonal basis. In addition, we have historically generated less revenues and income when temperatures are warmer in the winter and/or cooler in the summer. Thus, unusually mild winters and/or summers could have an adverse effect on our financial condition and results of operations.

Our utility businesses are subject to numerous environmental laws and regulations - Our utilities are subject to numerous stringent environmental laws and regulations by many federal, regional, state and local authorities, and international treaties. These laws and regulations generally concern emissions into the air, effluents into the water, use of water, wetlands preservation, remediation of contamination, waste disposal, disposal of coal combustion residuals, hazardous waste disposal, threatened and endangered species, and noise regulation, among others. We are also subject to Consent Decrees, which require construction of specific environmental control equipment, establish emission rate limits, require retirement or fuel switching of certain facilities and completing environmental mitigation projects. Failure to comply with such laws, regulations and Consent Decrees, or to obtain or comply with any necessary environmental permits pursuant to such laws and regulations, could result in injunctions, fines or other sanctions. Environmental laws and regulations affecting power generation and distribution are complex and subject to continued uncertainty, but have tended to become more stringent over time. These laws and regulations have imposed, and proposed laws and regulations could impose in the future, additional costs on the operation of our generating facilities. We have incurred, and will continue to incur, capital and other expenditures to comply with these and other environmental laws and regulations. Changes in, or new development of,

environmental restrictions may force us to incur significant expenses or expenses that may exceed our estimates. There can be no assurance that we would be able to recover all or any increased environmental costs from our customers. Failure to comply with the laws, regulations and Consent Decrees, changes in the laws and regulations and failure to recover costs of compliance may adversely impact our financial condition and results of operations.

Actions related to global climate change and reducing greenhouse gases (GHG) emissions could negatively impact us - Regulators, customers and investors continue to raise concerns about climate change and GHG emissions. National regulatory action is in flux, but international regulatory actions continue. We are focused on executing a long-term strategy to deliver reliable and affordable energy with lower carbon dioxide (CO2) emissions independent of changing policies and political landscape. However, it is unclear how these climate change concerns will ultimately impact us. We could incur costs or other obligations to comply with future GHG regulations, and could become the target of legal claims or challenges, because generating electricity using fossil fuels emits CO2 and other GHG. Further, investors may determine that we are too reliant on fossil fuels and not buy shares of our common stock, or sell shares of our common stock, which may cause our stock price to decrease. We could face additional pressures from customers or investors to more rapidly reduce CO2 on a voluntary-basis, including faster adoption of lower carbon technologies and management of excess renewable energy credits. The EPA's approach and timing for implementing rules to regulate carbon emissions at fossil-fueled electric generating units remains undecided and subject to litigation. We cannot provide any assurance regarding the potential impacts of climate change policy or GHG regulations on our operations and these could have a material adverse impact on our financial condition and results of operations.

We are dependent on the capital markets and could be negatively impacted by disruptions in the capital markets - Successful implementation of our strategic plan is dependent upon our ability to access the capital markets under competitive terms and rates. We have forecasted capital expenditures of approximately $5 billion over the next four years. Disruption, uncertainty or volatility in those markets could increase our cost of capital or limit the availability of capital. Disruptions could be caused by Federal Reserve policies and actions, currency concerns, economic downturn or uncertainty, monetary policies, a negative view of the utility industry or our company, failures of financial institutions, U.S. debt management concerns, U.S. debt limit and budget debates, including government shutdowns, European and worldwide sovereign debt concerns, other global or geopolitical events, or other factors. Increases in interest rates may cause the price of our equity securities to decline. Any disruptions in capital markets could adversely impact our ability to implement our strategic plan.

We rely on our strong credit ratings to access the credit markets. If our credit ratings are downgraded for any reason, such as Tax Reform impacts or general negative outlook for the utility industry, we could pay higher interest rates in future financings, the pool of potential lenders could be reduced, borrowing costs under existing credit facilities could increase, our access to the commercial paper market could be limited, or we could be required to provide additional credit assurance, including cash collateral, to contract counterparties. If our access to capital were to become significantly constrained or costs of capital increased significantly due to lowered credit ratings, prevailing industry conditions, regulatory constraints, volatility of the capital markets or other factors, our financial condition and results of operations could be adversely affected.

Regional and national economic conditions could have an unfavorable impact on us - Our utility and non-utility businesses follow the economic cycles of the customers we serve and credit risk of counterparties we do business with. Adverse economic conditions in our service territories can adversely affect the financial condition of our customers and reduce their demand for electricity and natural gas. Economic conditions may not create enough growth to replace lost energy demand or to grow energy demand. Reduced volumes of electricity and natural gas sold, or the inability to collect unpaid bills from our customers due to deterioration in national or regional economic conditions, could adversely impact our financial condition and results of operations.

Threats of terrorism and catastrophic events that could result from terrorism may impact our operations in unpredictable ways - We are subject to direct and indirect effects of terrorist threats and activities. Generation, transmission and distribution facilities, in general, have been identified as potential targets of physical or cyber attacks. Physical attacks on transmission and distribution facilities that appeared to be terrorist-style attacks have occurred. The risks posed by such attacks could include, among other things, the inability to generate, purchase or distribute electric energy or obtain fuel sources, the increased cost of security and insurance, the disruption of, volatility in, or other effects on capital markets, and a decline in the economy and/or energy usage within our service territories, all of which could adversely impact our financial condition and results of operations. In addition, the cost of repairing damage to our facilities and infrastructure due to acts of terrorism, and the loss of revenue if such events prevent us from providing utility service to our customers, could adversely impact our financial condition and results of operations.

We may not be able to fully recover costs related to commodity prices - We have natural gas and coal supply and transportation contracts in place for some of the natural gas and coal we require to generate electricity. We also have transportation and supply agreements in place to facilitate delivery of natural gas to our customers. Our counterparties to these contracts may not fulfill their obligations to provide natural gas or coal to us due to financial or operational problems, such as natural disasters or severe weather. If we were unable to obtain enough natural gas or coal for our electric generating facilities under our existing contracts, or to obtain electricity under existing or future purchased power agreements, we could be required to purchase natural gas or coal at higher prices or forced to purchase electricity from higher-cost generating resources in the MISO energy market. If, for natural gas delivery to our customers, we were unable to obtain our natural gas supply requirements under existing or future natural gas supply and transportation contracts, we could be required to purchase natural gas at higher prices from other sources. Natural gas market prices have generally been stable recently, but have been volatile in the past during periods of extremely cold temperatures or disruption in supply caused by major storms or pipeline explosions. We may not be able to pass on the changes in costs to our customers, especially at WPL where we do not have a retail electric automatic fuel cost adjustment clause. Increases in prices and costs due to disruptions that are not fully and timely recovered in rates may adversely impact our financial condition and results of operations.

We may not be able to fully recover higher transmission costs - Neither IPL nor WPL own or operate electric transmission facilities, however, both IPL and WPL pay for the use of the interstate electric transmission system based upon FERC-regulated rates. IPL and WPL rely primarily on the use of the ITC Midwest LLC (ITC) and American Transmission Company LLC (ATC) transmission systems, respectively. Due to the formula rates used by ITC and ATC to charge their customers and possible future changes to these rates, there is uncertainty regarding IPL's and WPL's future electric transmission service expense. In addition, FERC may change the way transmission companies set rates to socialize transmission system upgrades or to differently price generation resources necessary to maintain system reliability and resiliency. The prices that IPL and WPL charge for electricity may not totally compensate for the increase in such transmission costs. We may not be able to fully or timely pass on the increases in such transmission costs to our customers. In addition, if the transmission cost rider at IPL or escrow accounting treatment of transmission costs at WPL are amended or removed, we may not be able to fully recover transmission costs. Inability to fully recover transmission costs in a timely manner may adversely impact our financial condition and results of operations.

We face risks associated with operating electric and natural gas infrastructure - The operation of electric generating facilities involves many risks, including start-up risks, breakdown or failure of equipment, failure of generating facilities including wind turbines, the dependence on a specific fuel source, including the supply and transportation of fuel, the risk of performance below expected or contracted levels of output or efficiency, employee safety, operator error and compliance with mandatory reliability standards. Our energy delivery infrastructure is aging, which increases certain risks, including breakdown or failure of equipment and fires developing from our power lines. In addition, the North American transmission grid is highly interconnected and, in extraordinary circumstances, disruptions at particular points within the grid could cause an extensive power outage in our delivery systems. Increased utilization of customer- and third party-owned generation technologies could disrupt the reliability and balance of the electricity grid. Further, the transmission system in our utilities' service territories can experience constraints limiting the ability to transmit electric energy within our service territories. The transmission constraints could result in an inability to deliver energy from generating facilities, particularly wind generating facilities, to the national grid, or to access lower cost sources of electric energy. We also have obligations to provide electric service under regulatory requirements and contractual commitments. Failure to meet our service obligations could adversely impact our financial condition and results of operations.

The operation of our gas transmission and distribution infrastructure also involves many risks, such as leaks, explosions, mechanical problems and employee and public safety, which could cause substantial financial losses. These risks could result in loss of human life, significant damage to property, environmental emissions, impairment of our operations and substantial losses to us. We are also responsible for compliance with new and changing mandatory reliability and safety standards, including anticipated new regulations under the Pipeline and Hazardous Materials Safety Administration. Our infrastructure is aging, which could impact safety and compliance with possible new regulations. Failure to meet these standards could result in substantial fines. Electric and gas infrastructure operations could be impacted by future compliance with the Clean Power Plan. We also have obligations to provide service under regulatory requirements and contractual commitments. Failure to meet our service obligations could adversely impact our financial condition and results of operations.

Storms or other natural disasters may impact our operations in unpredictable ways - Storms and other natural disasters, including events such as floods, tornadoes, blizzards, ice storms, droughts, fires, solar flares or pandemics may adversely impact our ability to generate, purchase or distribute electric energy and gas or obtain fuel or other critical supplies. In addition, we could incur large costs to repair damage to our generating facilities and electric and gas infrastructure, or costs related to environmental remediation, due to storms or other natural disasters. The restoration costs may not be fully covered

by insurance policies and may not be fully recovered in rates, or recovery in rates may be delayed. Storms and natural disasters may impact our customers and the resulting reduced demand for energy could cause lower sales and revenues, which may not be replaced or recovered in rates, or rate recovery may be delayed. Any of these items could adversely impact our financial condition and results of operations.

We may incur material post-closing adjustments related to past asset and business divestitures - We have sold certain non-utility subsidiaries such as Whiting Petroleum Corporation (Whiting Petroleum), as well as regulated assets such as our Minnesota electric and natural gas distribution assets. We may continue to incur liabilities relating to our previous ownership of, or the transactions pursuant to which we disposed of, these subsidiaries and assets. Any potential liability depends on a number of factors outside of our control, including the financial condition of Whiting Petroleum and/or its assignees. Any required payments on retained liabilities, guarantees or indemnification obligations with respect to Whiting Petroleum, the sales of our Minnesota electric and natural gas distribution assets, or other future asset or business divestitures, could adversely impact our financial condition and results of operations.

We are subject to limitations on our ability to pay dividends - Alliant Energy is a holding company with no significant operations of its own. The primary sources of funds for Alliant Energy to pay dividends to its shareowners are dividends and distributions from its subsidiaries, primarily its utility subsidiaries. Our subsidiaries are separate and distinct legal entities and have no obligation to pay any amounts to us, whether by dividends, distributions, loans or other payments. The ability of our subsidiaries to pay dividends or make distributions to us and, accordingly, our ability to pay dividends on Alliant Energy common stock will depend on regulatory limitations, earnings, cash flows, capital requirements and general financial condition of our subsidiaries. Our utilities have dividend payment restrictions based on the terms of any outstanding preferred stock and regulatory limitations applicable to them. If we do not receive adequate dividends and distributions from our subsidiaries, then we may not be able to make, or may have to reduce, dividend payments on Alliant Energy common stock.

Our pension and other postretirement benefits plans are subject to investment and interest rate risk that could negatively impact our financial condition - We have pension and other postretirement benefits plans that provide benefits to many of our employees and retirees. Costs of providing benefits and related funding requirements of these plans are subject to changes in the market value of the assets that fund the plans. The funded status of the plans and the related costs reflected in our financial statements are affected by various factors, which are subject to an inherent degree of uncertainty, including economic conditions, financial market performance, interest rates, life expectancies and demographics. Recessions and volatility in the domestic and international financial markets have negatively affected the asset values of our pension plans at various times in the past. Poor investment returns or lower interest rates may necessitate accelerated funding of the plans to meet minimum federal government requirements, which could have an adverse impact on our financial condition and results of operations.

Energy industry changes could have a negative effect on our businesses - We operate in a highly regulated business environment. The advent of new and unregulated markets has the potential to significantly impact our financial condition and results of operations. Further, competitors may not be subject to the same operating, regulatory and financial requirements that we are, potentially causing a substantial competitive disadvantage for us. Changes in technology could also alter the channels through which electric customers buy or utilize power, which could reduce the revenues or increase the expenses of our utility companies. Increased competition from any restructuring efforts in our primary retail electric service territories may have a significant adverse impact on our financial condition and results of operations.

We face risks related to non-utility operations - We rely on our non-utility operations for a portion of our earnings. If our non-utility investments do not perform at expected levels, we could experience a material adverse impact on our financial condition and results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Alliant Energy - As a holding company, Alliant Energy doesn't directly own any significant properties other than the stock of its subsidiaries. The principal properties of those subsidiaries are as follows:

IPL and WPL

Electric - At December 31, 2017, IPL's and WPL's EGUs by primary fuel type were as follows:

IPL Name of EGU and Location	Expected Retirement or Fuel Switch (a)	In-service Dates	Primary Dispatch Type (b)	Nameplate Capacity in MW	Generating Capacity in MW (c)
Marshalltown Generating Station (Units 1-3); Marshalltown, IA	N/A	2017	IN	706	630
Emery Generating Station (Units 1-3); Mason City, IA	N/A	2004	IN	603	535
M.L. Kapp Generating Station (Unit 2); Clinton, IA	N/A	1967	IN	218	101
Marshalltown Combustion Turbines (Units 1-3); Marshalltown, IA	N/A	1978	PK	189	112
Prairie Creek Generating Station (Unit 4); Cedar Rapids, IA	N/A	1967	PK	149	111
Burlington Combustion Turbines (Units 1-4); Burlington, IA	Retire by 6/1/18	1994-1996	PK	79	48
Red Cedar Combustion Turbine (Unit 1); Cedar Rapids, IA	Retire by 6/1/18	1996	PK	23	13
Total Gas				1,967	1,550
Ottumwa Generating Station (Unit 1); Ottumwa, IA (d)	N/A	1981	BL	348	330
Lansing Generating Station (Unit 4); Lansing, IA	N/A	1977	BL	275	227
Burlington Generating Station (Unit 1); Burlington, IA	Fuel switch by 12/31/21 (e)	1968	BL	212	199
George Neal Generating Station (Unit 4); Sioux City, IA (f)	N/A	1979	BL	179	161
George Neal Generating Station (Unit 3); Sioux City, IA (g)	N/A	1975	BL	164	128
Prairie Creek Generating Station (Units 1 and 3); Cedar Rapids, IA	Fuel switch or retire by 12/31/25 (e)	1958-1997	BL	65	37
Louisa Generating Station (Unit 1); Louisa, IA (h)	N/A	1983	BL	32	29
Total Coal				1,275	1,111
Lime Creek Combustion Turbines (Units 1-2); Mason City, IA	N/A	1991	PK	90	70
Total Oil				90	70
Whispering Willow - East (121 Units); Franklin Co., IA	N/A	2009	IN	200	32
Franklin County (60 Units); Franklin Co., IA	N/A	2012	IN	99	17
Total Wind				299	49
Dubuque Solar Garden; Dubuque, IA (i)	N/A	2017	IN	5	—
Total capacity				3,636	2,780

WPL Name of EGU and Location	Expected Retirement (a)	In-service Dates	Primary Dispatch Type (b)	Nameplate Capacity in MW	Generating Capacity in MW (c)
Riverside Energy Center (Units 1-3); Beloit, WI	N/A	2004	IN	675	542
Neenah Energy Facility (Units 1-2); Neenah, WI	N/A	2000	PK	371	285
South Fond du Lac Combustion Turbines (2 Units); Fond du Lac, WI (j)	N/A	1994	PK	191	147
Rock River Combustion Turbines (Units 3-6); Beloit, WI	Retire by 12/31/20	1967-1972	PK	169	138
Sheepskin Combustion Turbine (Unit 1); Edgerton, WI	Retire by 12/31/20	1971	PK	42	34
Total Gas				1,448	1,146
Columbia Energy Center (Units 1-2); Portage, WI (k)	N/A	1975-1978	BL	557	550
Edgewater Generating Station (Unit 5); Sheboygan, WI	N/A	1985	BL	414	410
Edgewater Generating Station (Unit 4); Sheboygan, WI (l)	Retire by 9/30/18 (e)	1969	BL	239	181
Total Coal				1,210	1,141
Bent Tree (122 Units); Freeborn Co., MN	N/A	2010-2011	IN	201	31
Cedar Ridge (41 Units); Fond du Lac Co., WI	N/A	2008	IN	68	10
Total Wind				269	41
Prairie du Sac Hydro Plant (8 Units); Prairie due Sac, WI	N/A	1914-1940	IN	33	12
Kilbourn Hydro Plant (4 Units); Wisconsin Dells, WI	N/A	1926-1939	IN	10	6
Total Hydro				43	18
Total capacity				2,970	2,346

(a) Expected dates for the retirement and fuel switching of these EGUs are subject to change depending on operational, regulatory, market and other factors. The potential retirement of other EGUs within the generation fleet continues to be evaluated. IPL and WPL are working with MISO, state regulatory commissions and other regulatory agencies, as required, to determine the final timing of certain of these actions. Final MISO studies could indicate that the retirement of an individual EGU may result in reliability issues and that transmission network upgrades for system reliability are necessary to enable such retirement. Under the current MISO tariff, the specific timing for the retirement of these EGUs could depend on the timing of the required transmission network upgrades as well as various operational, market and other factors.
(b) Base load EGUs (BL) are designed for nearly continuous operation at or near full capacity to provide the system base load. Intermediate EGUs (IN) follow system load changes with frequent starts and curtailments of output during low demand. Peak load EGUs (PK) are generally low efficiency, quick response units that run primarily when there is high demand.
(c) Based on the accredited generating capacity of the EGUs as of December 31, 2017 included in MISO's resource adequacy process for the planning period from June 2017 through May 2018.
(d) Represents IPL's 48% ownership interest in this 726 MW (nameplate capacity) / 687 MW (generating capacity) EGU, which is operated by IPL.
(e) Actions and plans for retirement or fuel switch meet requirements specified in IPL's and WPL's respective Consent Decree, which are discussed in Note 16(e).
(f) Represents IPL's 25.695% ownership interest in this 696 MW (nameplate capacity) / 626 MW (generating capacity) EGU, which is operated by MidAmerican Energy Company.
(g) Represents IPL's 28% ownership interest in this 584 MW (nameplate capacity) / 456 MW (generating capacity) EGU, which is operated by MidAmerican Energy Company.
(h) Represents IPL's 4% ownership interest in this 812 MW (nameplate capacity) / 730 MW (generating capacity) EGU, which is operated by MidAmerican Energy Company.
(i) This EGU did not receive any accredited generating capacity for the planning period from June 2017 through May 2018.
(j) Represents Units 2 and 3, which WPL owns. WPL also operates, but does not own, South Fond du Lac Combustion Turbines Units 1 and 4.
(k) Represents WPL's 50.1% ownership interest in this 1,112 MW (nameplate capacity) / 1,098 MW (generating capacity) EGU, which is operated by WPL.
(l) Represents WPL's 68.2% ownership interest in this 351 MW (nameplate capacity) / 265 MW (generating capacity) EGU, which is operated by WPL.

At December 31, 2017, IPL owned approximately 17,300 miles of overhead electric distribution line and approximately 3,200 miles of underground electric distribution cable, as well as approximately 550 substation distribution transformers, substantially all of which are located in Iowa. At December 31, 2017, WPL owned approximately 16,100 miles of overhead electric distribution line and approximately 5,700 miles of underground electric distribution cable, as well as approximately 300 substation distribution transformers, substantially all of which are located in Wisconsin.

Gas - IPL's and WPL's gas properties consist primarily of mains and services, meters, regulating and gate stations and other related transmission and distribution equipment. At December 31, 2017, IPL's gas distribution facilities included approximately 5,100 miles of gas mains located in Iowa and WPL's included approximately 4,500 miles of gas mains located in Wisconsin.

Other - IPL's and WPL's other property consists primarily of operating and storeroom facilities, vehicles, computer hardware and software, communication equipment and other miscellaneous tools and equipment. IPL's other property also includes steam service assets. Refer to Note 10(b) for information regarding WPL's lease of the Sheboygan Falls Energy Facility from AEF's Non-utility Generation business.

AEF - AEF's principal properties included in "Property, plant and equipment, net" on Alliant Energy's balance sheet at December 31, 2017 were as follows:

Non-utility Generation - Includes the Sheboygan Falls Energy Facility, a 347 MW, simple-cycle, natural gas-fired facility near Sheboygan Falls, Wisconsin that was placed in service in 2005 and is leased to WPL. The Sheboygan Falls Energy Facility was accredited with 296 MW of generating capacity for MISO's resource adequacy process for the planning period from June 2017 through May 2018.

Transportation - Includes a short-line railway in Iowa with 114 miles of railroad track and 10 active locomotives; and a barge terminal on the Mississippi River.

Corporate Services - Corporate Services' property included in "Property, plant and equipment, net" on Alliant Energy's balance sheet at December 31, 2017 consisted primarily of a customer billing and information system for IPL and WPL and other computer software, and the corporate headquarters building located in Madison, Wisconsin.

ITEM 3. LEGAL PROCEEDINGS

Alliant Energy - None.

IPL - None.

WPL - None.

Other - Alliant Energy, IPL and WPL are involved in legal and administrative proceedings before various courts and agencies with respect to matters arising in the ordinary course of business. Although unable to predict the outcome of these matters, Alliant Energy, IPL and WPL believe that final disposition of these actions will not have a material effect on their financial condition or results of operations.

ITEM 4. MINE SAFETY DISCLOSURES

None.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The executive officers of Alliant Energy, IPL and WPL for which information must be included are the same; however, different positions may be held at the various registrants. None of the executive officers for Alliant Energy, IPL or WPL listed below are related to any member of the Board of Directors or nominee for director or any other executive officer. All of the executive officers have no definite terms of office and serve at the pleasure of the Board of Directors. The executive officers of Alliant Energy, IPL and WPL as of the date of this filing are as follows:

Name	Age as of Filing Date	Registrant	Positions
Patricia L. Kampling	58	Alliant Energy	Ms. Kampling has served as a director since January 2012, and as Chairman of the Board and Chief Executive Officer (CEO) since April 2012, and as President from February 2011 to December 2017.
		IPL and WPL	Ms. Kampling has served as a director since January 2012, and as Chairman of the Board and CEO since April 2012.
John O. Larsen	54	Alliant Energy	Mr. Larsen has served as President since January 2018. He previously served as Senior Vice President (VP) since February 2014 and as Senior VP-Generation from January 2010 to February 2014.
		IPL	Mr. Larsen has served as Senior VP since February 2014. He previously served as Senior VP-Generation since January 2010.
		WPL	Mr. Larsen has served as President since December 2010.
Robert J. Durian	47	Alliant Energy, IPL and WPL	Mr. Durian has served as Senior VP, Chief Financial Officer (CFO) and Treasurer since January 2018. He previously served as VP, CFO and Treasurer since December 2016; as VP, Chief Accounting Officer (CAO) and Treasurer from July 2016 to December 2016; as VP, CAO and Controller from July 2015 to July 2016; and as Controller and CAO from February 2011 to July 2015.
James H. Gallegos	57	Alliant Energy, IPL and WPL	Mr. Gallegos has served as Senior VP, General Counsel and Corporate Secretary since February 2015. He previously served as Senior VP and General Counsel since February 2014 and as VP and General Counsel from November 2010 to February 2014.
Douglas R. Kopp	64	Alliant Energy and WPL	Mr. Kopp has served as Senior VP since March 2014. He previously served as VP-Environmental Affairs since January 2013.
		IPL	Mr. Kopp has served as President since April 2014.
Benjamin M. Bilitz	43	Alliant Energy, IPL and WPL	Mr. Bilitz has served as CAO and Controller since December 2016. He previously served as Controller since July 2016 and as Assistant Controller from March 2011 to July 2016.

PART II

ITEM 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Common Stock Data - Alliant Energy's common stock trades on the New York Stock Exchange under the symbol "LNT." Quarterly sales price high and low ranges and dividends with respect to Alliant Energy's common stock were as follows:

Closing sales price at December 31, 2017: $42.61

Shareowners - At December 31, 2017, there were 26,165 holders of record of Alliant Energy's common stock, including holders through Alliant Energy's Shareowner Direct Plan. Alliant Energy is the sole common shareowner of all 13,370,788 and 13,236,601 shares of IPL and WPL common stock, respectively, currently outstanding. As a result, there is no established public trading market for the common stock of either IPL or WPL.

Dividends - In November 2017, Alliant Energy announced an increase in its targeted 2018 annual common stock dividend to $1.34 per share, which is equivalent to a quarterly rate of $0.335 per share, beginning with the February 2018 dividend payment. The timing and amount of future dividends is subject to an approved dividend declaration from Alliant Energy's Board of Directors, and is dependent upon earnings expectations, capital requirements, and general financial business conditions, among other factors.

Alliant Energy does not have any significant common stock dividend restrictions. Refer to Note 7 for information about IPL's and WPL's dividend restrictions and limitations on distributions to their parent company.

Common Stock Repurchases - A summary of Alliant Energy common stock repurchases for the quarter ended December 31, 2017 was as follows:

Period	Total Number of Shares Purchased (a)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plan (a)
October 1 to October 31	2,125	$42.99	—	N/A
November 1 to November 30	3,542	44.66	—	N/A
December 1 to December 31	491	43.94	—	N/A
	6,158	44.02	—	

(a) All shares were purchased on the open market and held in a rabbi trust under the DCP. There is no limit on the number of shares of Alliant Energy common stock that may be held under the DCP, which currently does not have an expiration date.

Other - Refer to "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" in Item 12 for details of securities authorized for issuance under equity compensation plans.

ITEM 6. SELECTED FINANCIAL DATA

Financial Information

Alliant Energy	2017 (a)	2016 (a)	2015 (a)	2014	2013
		(dollars in millions, except per share data)			
Income Statement Data:					
Operating revenues	**$3,382.2**	$3,320.0	$3,253.6	$3,350.3	$3,276.8
Amounts attributable to Alliant Energy common shareowners:					
Income from continuing operations, net of tax	**455.9**	373.8	380.7	385.5	364.2
Income (loss) from discontinued operations, net of tax	**1.4**	(2.3)	(2.5)	(2.4)	(5.9)
Net income	**457.3**	371.5	378.2	383.1	358.3
Common Stock Data:					
Earnings per weighted average common share attributable to Alliant Energy common shareowners (basic and diluted):					
Income from continuing operations, net of tax	**$1.99**	$1.65	$1.69	$1.74	$1.64
Loss from discontinued operations, net of tax	**$—**	($0.01)	($0.01)	($0.01)	($0.02)
Net income	**$1.99**	$1.64	$1.68	$1.73	$1.62
Common shares outstanding at year-end (000s)	**231,349**	227,674	226,918	221,871	221,887
Dividends declared per common share	**$1.26**	$1.175	$1.10	$1.02	$0.94
Market value per share at year-end	**$42.61**	$37.89	$31.225	$33.21	$25.80
Book value per share at year-end	**$18.08**	$16.96	$16.41	$15.50	$14.79
Market capitalization at year-end	**$9,857.8**	$8,626.6	$7,085.5	$7,368.3	$5,724.7
Other Selected Financial Data:					
Cash flows from operating activities	**$983.4**	$859.6	$871.2	$891.6	$731.0
Construction and acquisition expenditures	**$1,466.9**	$1,196.8	$1,034.3	$902.8	$798.3
Total assets at year-end	**$14,187.8**	$13,373.8	$12,495.2	$12,063.5	$11,092.5
Long-term obligations, net	**$4,870.6**	$4,325.1	$3,837.0	$3,768.7	$3,318.2
IPL					
Operating revenues	**$1,870.3**	$1,820.4	$1,774.5	$1,848.1	$1,818.8
Earnings available for common stock	**216.8**	215.6	186.0	181.6	172.0
Cash dividends declared on common stock	**156.1**	151.9	140.0	140.0	128.1
Cash flows from operating activities	**440.0**	361.9	385.0	406.1	232.6
Total assets	**7,606.0**	7,304.7	6,709.1	6,450.2	5,793.9
Long-term obligations, net	**2,406.6**	2,154.0	1,857.4	1,758.6	1,549.5
WPL					
Operating revenues	**$1,472.8**	$1,459.1	$1,435.1	$1,449.1	$1,406.3
Earnings available for common stock	**186.6**	190.4	176.3	180.4	177.5
Cash dividends declared on common stock	**125.9**	135.0	126.9	118.7	116.3
Cash flows from operating activities	**465.7**	521.4	449.8	424.4	423.3
Total assets	**5,756.5**	5,290.3	5,270.4	5,117.6	4,796.2
Long-term obligations, net	**1,914.3**	1,623.2	1,624.2	1,658.3	1,423.2

(a) Refer to "Results of Operations" in MDA for discussion of the 2017, 2016 and 2015 results of operations.

Alliant Energy is the sole common shareowner of all 13,370,788 and 13,236,601 shares of IPL's and WPL's common stock outstanding, respectively. As such, earnings per share data is not disclosed herein for IPL and WPL.

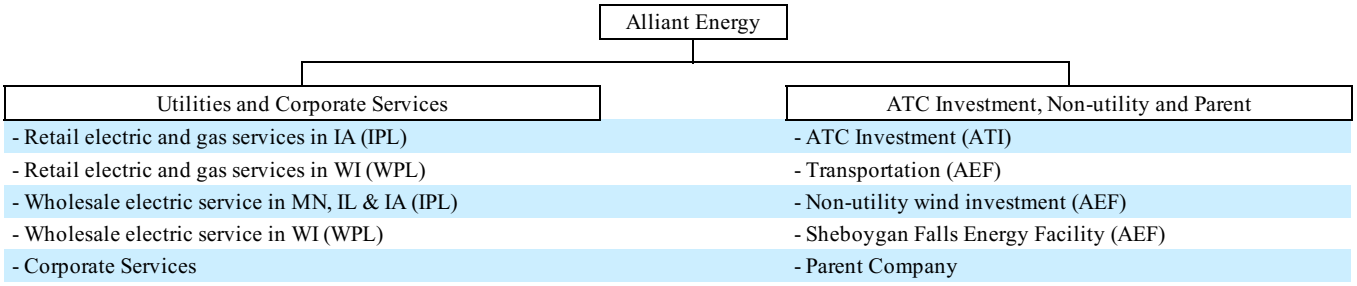
ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This MDA includes information relating to Alliant Energy, IPL and WPL, as well as AEF and Corporate Services. Where appropriate, information relating to a specific entity has been segregated and labeled as such. The following discussion and analysis should be read in conjunction with the Financial Statements and Notes included in this report. Unless otherwise noted, all "per share" references in MDA refer to earnings per diluted share.

EXECUTIVE OVERVIEW

Description of Business

General - Alliant Energy is a Midwest U.S. energy holding company whose primary subsidiaries are IPL, WPL, AEF and Corporate Services. IPL and WPL are public utilities, and AEF is the parent company for Alliant Energy's non-utility businesses and holds all of Alliant Energy's ATC Investment. Corporate Services provides administrative services to Alliant Energy and its subsidiaries. An illustration of Alliant Energy's primary businesses is shown below.



Utilities and Corporate Services - IPL and WPL own a portfolio of EGUs located in Iowa, Wisconsin and Minnesota with a diversified fuel mix including natural gas, renewable resources and coal. The output from these EGUs, supplemented with purchased power, is used to provide electric service to approximately 960,000 electric customers in the upper Midwest. The utility business also procures natural gas from various suppliers to provide service to approximately 410,000 retail gas customers in the upper Midwest. Alliant Energy's utility business is its primary source of earnings and cash flows. The earnings and cash flows from the utilities and Corporate Services business are sensitive to various external factors including, but not limited to, the amount and timing of rates approved by regulatory authorities, the impact of weather and economic conditions on electric and gas sales volumes and other factors listed in "Risk Factors" in Item 1A and "Forward-looking Statements."

ATC Investment, Non-utility Business and Parent - AEF holds all of Alliant Energy's ATC Investment. AEF also manages various businesses including Transportation (short-line railway and barge transportation services), a non-utility wind investment, the Sheboygan Falls Energy Facility and several other modest investments.

Financial Results - Alliant Energy's net income and EPS attributable to Alliant Energy common shareowners were as follows (dollars in millions, except per share amounts):

	2017		2016	
	Income	**EPS**	Income (Loss)	EPS
Continuing operations:				
Utilities and Corporate Services	**$416.7**	**$1.82**	$397.3	$1.75
ATC Investment	**25.4**	**0.11**	23.1	0.10
Non-utility and Parent	**13.8**	**0.06**	(46.6)	(0.20)
Income from continuing operations	**455.9**	**1.99**	373.8	1.65
Income (loss) from discontinued operations	**1.4**	—	(2.3)	(0.01)
Net income	**$457.3**	**$1.99**	$371.5	$1.64

The table above includes EPS from continuing operations for utilities and Corporate Services, ATC Investment, and non-utility and parent, which are non-GAAP financial measures. Alliant Energy believes these non-GAAP financial measures are useful to investors because they facilitate an understanding of segment performance and trends, and provide additional information about Alliant Energy's operations on a basis consistent with the measures that management uses to manage its operations and evaluate its performance.

Alliant Energy's, IPL's and WPL's income from continuing operations increased (decreased) by $82 million, $1 million and ($4) million, respectively, in 2017 compared to 2016. Alliant Energy's increase was primarily due to asset valuation charges at AEF related to the Franklin County wind farm in 2016, higher margins resulting from IPL's interim retail electric base rate increase implemented in April 2017 and WPL's retail electric and gas base rate increases implemented in January 2017, and the effects of Tax Reform, partially offset by higher depreciation expense, higher energy efficiency cost recovery amortization at WPL, and the estimated temperature impacts on IPL's and WPL's retail electric and gas sales. WPL's decrease was also impacted by reduced equity income resulting from the transfer of WPL's investment in ATC to ATI on December 31, 2016.

Refer to "Results of Operations" for additional details regarding the various factors impacting earnings during 2017, 2016 and 2015.

2017 Overview - In 2017, Alliant Energy, IPL and WPL focused on achieving financial objectives and executing their strategic plan. Key developments in 2017 include the following:

- **Tax Reform -** In December 2017, Tax Reform was enacted. The enactment of Tax Reform had a material impact on the 2017 financial statements since changes in tax laws must be recognized in the period in which the law is enacted. The most significant provision of Tax Reform was the reduction in the federal corporate tax rate from 35% to 21%, which required a re-measurement of deferred tax assets and liabilities in December 2017. The net impacts of re-measuring deferred taxes associated with regulated utility operations were recorded in regulatory assets and regulatory liabilities and will be utilized to provide benefits to customers in the future. Refer to Note 11 for further discussion of the impacts of Tax Reform.
- **IPL's Marshalltown Generating Station -** Marshalltown, a 706 MW natural gas-fired combined-cycle EGU, was placed into service in April 2017. Final capital expenditures were $645 million to construct the EGU and a pipeline to supply natural gas to the EGU, excluding transmission network upgrades and AFUDC.
- **Franklin County Wind Farm -** In April 2017, the 99 MW Franklin County wind farm was transferred from AEF to IPL.
- **IPL's and WPL's Potential Expansion of Wind Generation -** IPL and WPL currently plan on expanding their wind generation by up to 1,000 MW and 200 MW, respectively, by the end of 2020. In 2016, IPL received approval from the IUB for the first 500 MW of wind generation. In August 2017, IPL filed an application with the IUB for advance rate-making principles for a second 500 MW of wind generation, and is currently expecting a decision from the IUB in the first quarter of 2018. In November 2017, WPL filed for approval from the PSCW and FERC to acquire 55 MW of FWEC, which is a 129 MW wind farm located in Wisconsin. WPL received approval from FERC for the FWEC acquisition in January 2018 and is currently expecting a decision from the PSCW in the first half of 2018. WPL currently expects to file for approval from the PSCW for the remaining portion of its wind expansion plan in the first half of 2018. Refer to "Strategic Overview" for further discussion. The amount and timing of these wind projects will largely depend on regulatory approvals and the acquisition of wind sites.
- **WPL's Construction of West Riverside -** In October 2017, WPL received an order from the PSCW authorizing various electric cooperatives, which currently have wholesale power supply agreements with WPL, to acquire approximately 65 MW of West Riverside while the EGU is being constructed. As part of the electric cooperatives' acquisitions, which were finalized in January 2018, the current wholesale power supply agreements with the various electric cooperatives were extended by at least four years until 2026 with automatic continuation of such agreements unless terminated by either party, with a five-year notice requirement.
- **Non-utility Wind Investment in Oklahoma -** In July 2017, a wholly-owned subsidiary of AEF acquired a 50% cash equity ownership interest in a 225 MW non-utility wind farm located in Oklahoma. Refer to Note 6(a) for further discussion.
- **IPL's Retail Electric Rate Review (2016 Test Year) -** In April 2017, IPL filed a request with the IUB to increase annual electric base rates for its Iowa retail electric customers. The request was based on a 2016 historical Test Year as adjusted for certain known and measurable changes occurring up to 12 months after the commencement of the proceeding. The key drivers for the filing included recovery of capital projects, primarily power grid modernization and investments that advance cleaner energy, including Marshalltown. An interim retail electric base rate increase of $102 million, or approximately 7%, on an annual basis, was implemented effective April 13, 2017. In September 2017, IPL reached a partial, non-unanimous settlement agreement with the Iowa Office of Consumer Advocate, the Iowa Business Energy Coalition and the Large Energy Group to increase annual retail electric base rates by $130 million, or approximately 9%. In February 2018, the IUB issued an order approving the settlement. Final rates are currently expected to be effective in the first half of 2018 once all motions for reconsideration have been addressed and final tariffs have been approved by the IUB.

- **MISO Transmission Owner Return on Equity Complaints -** A group of MISO cooperative and municipal utilities previously filed two complaints with FERC requesting a reduction to the base return on equity used by MISO transmission owners, including ITC and ATC, to determine electric transmission costs billed to utilities, including IPL and WPL. In 2016, FERC issued an order on the first complaint and established a base return on equity of 10.32%, excluding any incentive adders granted by FERC, effective September 28, 2016, and for the refund period from November 12, 2013 through February 11, 2015 (first complaint period). In 2017, Alliant Energy, IPL and WPL received the refunds for the first complaint period of $50 million, $39 million and $11 million, respectively, after final true-ups. Pursuant to IUB approval, IPL's retail portion of the refund from ITC was refunded to its retail customers in 2017. WPL's retail portion of the refund from ATC will remain in a regulatory liability until such refunds are approved to be returned to retail customers in a future rate proceeding. A decision from FERC on the second complaint is currently expected in 2018.
- **Credit Facility Agreement -** In August 2017, Alliant Energy, IPL and WPL entered into a single new credit facility agreement, which expires in August 2022. The new credit facility agreement includes financial covenants similar to those that were included in the previous credit facility agreements. As of December 31, 2017, the short-term borrowing capacity totaled $1 billion ($400 million for Alliant Energy at the parent company level, $250 million for IPL and $350 million for WPL).
- **At-the-Market Offering Program -** In 2017, Alliant Energy issued 3.1 million shares of common stock through an at-the-market offering program and received cash proceeds of $124 million, net of $1 million in commissions and fees. The proceeds from the issuances of common stock were used for general corporate purposes.

Future Developments - The following includes key items expected to impact Alliant Energy, IPL and WPL in the future:

- **Planned Utility Rate Reviews -** IPL currently expects to make a retail gas rate filing in the second quarter of 2018 based on a 2017 historical Test Year. WPL currently expects to make a retail electric and gas rate filing in the second quarter of 2018 for the 2019/2020 Test Period. Refer to "Rate Matters" for further discussion.

2018 Forecast - In 2018, the following financing activities, and impacts to results of operations, are currently anticipated to occur:

- **Financing Plans -** Alliant Energy currently expects to issue up to $200 million of common stock in 2018 through one or more offerings and its Shareowner Direct Plan. IPL currently expects to issue up to $700 million of long-term debt securities in 2018, of which $350 million would be used to retire long-term debt maturing in 2018. AEF currently expects to issue up to $1.0 billion of long-term debt in 2018, of which $595 million would be used to refinance expiring term loans.
- **Common Stock Dividends -** Alliant Energy announced a 6% increase in its targeted 2018 annual common stock dividend to $1.34 per share, which is equivalent to a quarterly rate of $0.335 per share, beginning with the February 2018 dividend payment. The timing and amount of future dividends is subject to an approved dividend declaration from Alliant Energy's Board of Directors, and is dependent upon earnings expectations, capital requirements, and general financial business conditions, among other factors.
- **Utility Electric and Gas Margins -** Alliant Energy and IPL currently expect an increase in electric and gas margins in 2018 compared to 2017 as a result of base rate increases from final rates implemented for IPL's retail electric rate review (2016 Test Year) and interim rates for IPL's planned retail gas rate review (2017 Test Year). Alliant Energy and WPL currently expect an increase in electric margins from lower electric transmission service expense in 2018 compared to 2017 due to amortizations of previously over-recovered transmission expenses as approved in WPL's retail electric rate review (2017/2018 Test Year). Refer to "Rate Matters" for further discussion of these rate reviews.
- **Depreciation and Amortization Expenses -** Alliant Energy and IPL currently expect an increase in depreciation and amortization expenses in 2018 compared to 2017 due to property additions, and the implementation of updated depreciation rates for IPL as a result of a recently completed depreciation study, which are currently expected to be effective in the first half of 2018.
- **Interest Expense -** Alliant Energy currently expects interest expense to increase in 2018 compared to 2017 primarily due to financings completed in 2017 and planned in 2018 as discussed above.
- **AFUDC -** Alliant Energy currently expects AFUDC to increase in 2018 compared to 2017 primarily due to increased CWIP balances related to IPL's expansion of wind generation and WPL's West Riverside facility.

RESULTS OF OPERATIONS

Overview - "Executive Overview" provides an overview of Alliant Energy's, IPL's and WPL's 2017 and 2016 earnings. Additional earnings details for 2017, 2016 and 2015 are discussed below.

Results of operations include financial information prepared in accordance with GAAP as well as utility electric margins and utility gas margins, which are not measures of financial performance under GAAP. Utility electric margins are defined as electric operating revenues less electric production fuel, purchased power and electric transmission service expenses. Utility gas margins are defined as gas operating revenues less cost of gas sold. Utility electric margins and utility gas margins are non-GAAP financial measures because they exclude other utility and non-utility operating revenues, other operation and maintenance expenses, depreciation and amortization expenses, and taxes other than income tax expense.

Management believes that utility electric and gas margins provide a meaningful basis for evaluating and managing utility operations since electric production fuel, purchased power and electric transmission service expenses and cost of gas sold are generally passed through to customers, and therefore, result in changes to electric and gas operating revenues that are comparable to changes in such expenses. The presentation of utility electric and gas margins herein is intended to provide supplemental information for investors regarding operating performance. These utility electric and gas margins may not be comparable to how other entities define utility electric and gas margin. Furthermore, these measures are not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance.

Operating income and a reconciliation of utility electric and gas margins to the most directly comparable GAAP measure, operating income, was as follows (in millions):

	Alliant Energy			IPL			WPL		
	2017	2016	2015	**2017**	2016	2015	**2017**	2016	2015
Operating income	**$653.4**	$537.0	$577.0	**$296.9**	$270.8	$241.9	**$323.2**	$327.0	$308.7
Electric utility operating revenues	**$2,894.7**	$2,875.5	$2,770.5	**$1,598.9**	$1,569.7	$1,503.8	**$1,295.8**	$1,305.8	$1,266.7
Electric production fuel and purchased power expenses	**(818.1)**	(854.0)	(837.7)	**(443.6)**	(430.5)	(428.4)	**(374.5)**	(423.5)	(409.3)
Electric transmission service expense	**(480.9)**	(527.9)	(485.3)	**(310.4)**	(359.7)	(328.2)	**(170.5)**	(168.2)	(157.1)
Utility Electric Margin (non-GAAP)	**1,595.7**	1,493.6	1,447.5	**844.9**	779.5	747.2	**750.8**	714.1	700.3
Gas utility operating revenues	**400.9**	355.4	381.2	**226.0**	204.0	217.3	**174.9**	151.4	163.9
Cost of gas sold	**(211.4)**	(194.3)	(219.1)	**(115.6)**	(111.0)	(123.3)	**(95.8)**	(83.3)	(95.8)
Utility Gas Margin (non-GAAP)	**189.5**	161.1	162.1	**110.4**	93.0	94.0	**79.1**	68.1	68.1
Other utility operating revenues	**47.5**	48.6	57.9	**45.4**	46.7	53.4	**2.1**	1.9	4.5
Non-utility operating revenues	**39.1**	40.5	44.0	**—**	—	—	**—**	—	—
Asset valuation charges for Franklin County wind farm	**—**	(86.4)	—	**—**	—	—	**—**	—	—
Other operation and maintenance expenses	**(651.0)**	(606.5)	(629.5)	**(403.8)**	(383.7)	(389.9)	**(249.0)**	(219.8)	(235.4)
Depreciation and amortization expenses	**(461.8)**	(411.6)	(401.3)	**(245.0)**	(210.8)	(207.2)	**(212.9)**	(192.5)	(184.3)
Taxes other than income tax expense	**(105.6)**	(102.3)	(103.7)	**(55.0)**	(53.9)	(55.6)	**(46.9)**	(44.8)	(44.5)
Operating income	**$653.4**	$537.0	$577.0	**$296.9**	$270.8	$241.9	**$323.2**	$327.0	$308.7

Operating Income Variances - Variances between periods in operating income were as follows (in millions):

2017 vs. 2016:	Alliant Energy	IPL	WPL
Asset valuation charges for Franklin County wind farm in 2016 (Refer to Note 3 for details)	$86	$—	$—
Total higher utility electric margin variance (Refer to details below)	102	65	37
Total higher utility gas margin variance (Refer to details below)	28	17	11
Higher other operation and maintenance expenses variance (Refer to details below)	(45)	(20)	(29)
Higher depreciation and amortization expense primarily due to additional plant in service in 2017, including impacts from Marshalltown	(33)	(29)	(8)
Higher depreciation expense at WPL due to updated depreciation rates effective January 2017 approved by the PSCW and FERC (Refer to Note 1(e) for details)	(12)	—	(12)
Higher depreciation expense at IPL due to write-down of regulatory assets resulting from the IPL electric rate review settlement in 2017 (Refer to Note 2 for details)	(5)	(5)	—
Other	(5)	(2)	(3)
	$116	$26	($4)

2016 vs. 2015:	Alliant Energy	IPL	WPL
Asset valuation charges for Franklin County wind farm in 2016 (Refer to Note 3 for details)	($86)	$—	$—
Total higher utility electric margin variance (Refer to details below)	46	32	14
Total lower utility gas margin variance (Refer to details below)	(1)	(1)	—
Total lower other operation and maintenance expenses variance (Refer to details below)	23	6	16
Higher amortization expense from the new customer billing and information system placed in service in 2015	(8)	(4)	(4)
Higher depreciation and amortization expense primarily due to additional plant in service in 2016	(2)	—	(4)
Other	(12)	(4)	(4)
	($40)	$29	$18

Electric Revenues and Sales Summary - Electric revenues (in millions), and MWh sales (in thousands), were as follows:

	Revenues			MWhs Sold		
	2017	2016	2015	**2017**	2016	2015
Alliant Energy						
Retail	**$2,569.6**	$2,564.8	$2,474.1	**25,095**	25,339	25,380
Sales for resale	**268.8**	266.7	249.5	**5,003**	4,399	4,842
Other	**56.3**	44.0	46.9	**94**	100	129
	$2,894.7	$2,875.5	$2,770.5	**30,192**	29,838	30,351
IPL						
Retail	**$1,448.0**	$1,442.5	$1,410.2	**14,356**	14,523	14,824
Sales for resale	**114.6**	97.8	61.5	**2,169**	1,406	1,023
Other	**36.3**	29.4	32.1	**38**	41	67
	$1,598.9	$1,569.7	$1,503.8	**16,563**	15,970	15,914
WPL						
Retail	**$1,121.6**	$1,122.3	$1,063.9	**10,739**	10,816	10,556
Sales for resale	**154.2**	168.9	188.0	**2,834**	2,993	3,819
Other	**20.0**	14.6	14.8	**56**	59	62
	$1,295.8	$1,305.8	$1,266.7	**13,629**	13,868	14,437

Gas Revenues and Sales Summary - Gas revenues (in millions), and Dth sales (in thousands), were as follows:

	Revenues			Dths Sold		
	2017	2016	2015	**2017**	2016	2015
Alliant Energy						
Retail	**$364.6**	$322.4	$349.9	**49,250**	47,743	48,635
Transportation/Other	**36.3**	33.0	31.3	**76,916**	77,485	74,162
	$400.9	$355.4	$381.2	**126,166**	125,228	122,797
IPL						
Retail	**$202.2**	$183.1	$198.4	**26,580**	26,230	26,877
Transportation/Other	**23.8**	20.9	18.9	**39,365**	37,158	34,129
	$226.0	$204.0	$217.3	**65,945**	63,388	61,006
WPL						
Retail	**$162.4**	$139.3	$151.5	**22,670**	21,513	21,758
Transportation/Other	**12.5**	12.1	12.4	**37,551**	40,327	40,033
	$174.9	$151.4	$163.9	**60,221**	61,840	61,791

Temperatures - Estimated increases (decreases) to electric and gas margins from the impacts of temperatures were as follows (in millions):

	Electric Margins			**Gas Margins**		
	2017	2016	2015	**2017**	2016	2015
IPL	**($8)**	$3	($7)	**($4)**	($4)	($2)
WPL	**(8)**	1	(4)	**(2)**	(3)	(2)
Total Alliant Energy	**($16)**	$4	($11)	**($6)**	($7)	($4)

Utility Electric Margin Variances - The following items contributed to increased (decreased) utility electric margins as follows (in millions):

2017 vs. 2016:	Alliant Energy	IPL	WPL
Higher margins at IPL from the impact of its 2016 Test Year interim retail electric base rate increase (Refer to Note 2 for details)	$77	$77	$—
Higher margins at WPL from the impact of its 2017/2018 Test Period retail electric base rate increase (Refer to Note 2 for details)	63	—	63
Higher revenues at IPL due to 2016 retail electric customer billing credits related to the approved retail electric base rate freeze through 2016 (Refer to Note 2 for details)	9	9	—
Higher electric revenues from reimbursements for hurricane assistance relief in 2017 (hurricane assistance electric revenues are offset in other operation and maintenance expenses)	6	3	3
Estimated changes in sales volumes caused by temperatures (Refer to "Temperatures" above for details)	(20)	(11)	(9)
Revenue requirement adjustment in 2016 related to certain tax benefits (Refer to Note 2 for details)	(14)	(14)	—
Changes in electric fuel-related costs, net of recoveries at WPL (a)	(12)	—	(12)
Lower wholesale margins at WPL primarily due to the expiration of a wholesale power supply agreement on May 31, 2017	(8)	—	(8)
Other	1	1	—
	$102	$65	$37

2016 vs. 2015:	Alliant Energy	IPL	WPL
Higher revenues at IPL due to lower retail electric customer billing credits related to the approved retail electric base rate freeze through 2016 (Refer to Note 2 for details)	$15	$15	$—
Estimated changes in sales volumes caused by temperatures (Refer to "Temperatures" above for details)	15	10	5
Higher revenues at IPL due to fewer electric tax benefit rider credits on customers' bills (Refer to Note 2 for details)	8	8	—
Higher electric transmission service expense at WPL	(11)	—	(11)
Other (b)	19	(1)	20
	$46	$32	$14

(a) WPL estimates the increase (decrease) to electric margins from amounts within the approved bandwidth of plus or minus 2% of forecasted fuel-related expenses determined by the PSCW each year was approximately ($6) million, $6 million and $6 million in 2017, 2016 and 2015, respectively.
(b) Includes increases in temperature-normalized retail sales volumes at WPL in 2016. Refer to "Electric Sales Trends" below for more information.

Electric Sales Trends - Alliant Energy's retail electric sales volumes decreased 1% in 2017 and remained unchanged in 2016. During 2017, the decrease was primarily due to the impact of lower residential and commercial sales due to cooler summer temperatures during 2017 compared to the same period in 2016 and an extra day of retail sales during 2016 due to the leap year, partially offset by increases in WPL's industrial sales from higher customer production and customer expansions.

During 2016, retail electric sales remained unchanged. Increases from the impact of temperatures on residential and commercial sales resulting in higher cooling demand, an extra day of retail sales during the first quarter of 2016 due to the leap year, and higher commercial and industrial sales driven by customer expansions were offset by decreases from IPL's sale of its Minnesota electric distribution assets in 2015.

Utility Gas Margin Variances - The following items contributed to increased (decreased) utility gas margins as follows (in millions):

2017 vs. 2016:	Alliant Energy	IPL	WPL
Higher margins at WPL from the impact of its 2017/2018 Test Period retail gas base rate increase (Refer to Note 2 for details)	$9	$—	$9
Higher revenues at IPL related to changes in recovery amounts for energy efficiency costs through the energy efficiency rider (a)	8	8	—
Higher revenues at IPL due to lower gas tax benefit rider credits on customer's bills (Refer to Note 2 for details)	6	6	—
Estimated changes in sales volumes caused by temperatures (Refer to "Temperatures" above for details)	1	—	1
Other	4	3	1
	$28	$17	$11

2016 vs. 2015:	Alliant Energy	IPL	WPL
Estimated changes in sales volumes caused by temperatures (Refer to "Temperatures" above for details)	($3)	($2)	($1)
Other	2	1	1
	($1)	($1)	$—

(a) Changes in gas energy efficiency revenues were mostly offset by changes in energy efficiency expense included in other operation and maintenance expenses.

Other Operation and Maintenance Expenses - The following items contributed to (increased) decreased other operation and maintenance expenses as follows (in millions):

2017 vs. 2016:	Alliant Energy	IPL	WPL
Higher energy efficiency cost recovery amortizations at WPL (a)	($27)	$—	($27)
Charges related to cancelled software projects in 2017	(6)	(3)	(3)
Higher distribution expense for hurricane assistance relief in 2017 (hurricane assistance relief expenses are offset in electric margins)	(6)	(3)	(3)
Write-down of regulatory assets due to the IPL electric rate review settlement in 2017 (Refer to Note 2 for details)	(4)	(4)	—
Higher energy efficiency expense at IPL (primarily offset by gas revenues)	(3)	(3)	—
Other	1	(7)	4
	($45)	($20)	($29)

2016 vs. 2015:	Alliant Energy	IPL	WPL
Lower energy efficiency cost recovery amortizations at WPL (a)	$15	$—	$15
Losses on sales of IPL's Minnesota distribution assets recorded in 2015 (Refer to Note 3 for details)	14	14	—
Voluntary employee separation charges in 2015 (Refer to Note 12(a) for details)	8	5	3
Higher bad debt expense at IPL (b)	(9)	(9)	—
Higher stock-based performance compensation expense (Refer to Note 12(b) for details)	(7)	(4)	(3)
Higher employee benefits-related expense (c)	(7)	(5)	(2)
Other (includes lower costs due to cost controls and operational efficiencies)	9	5	3
	$23	$6	$16

(a) The December 2016 PSCW order for WPL's 2017/2018 Test Period electric and gas base rate review authorized changes in energy efficiency cost recovery amortizations for 2017 and 2018. The July 2014 PSCW order for WPL's 2015/2016 Test Period electric and gas base rate review authorized changes in energy efficiency cost recovery amortizations for 2015 and 2016. Regulatory amortizations at WPL related to energy efficiency costs were $16 million, ($11) million and $4 million in 2017, 2016 and 2015, respectively.
(b) Primarily due to an increase in IPL's allowance for doubtful accounts as a result of increases in past due accounts receivable.
(c) Primarily due to an increase in retirement plans costs and other employee benefits-related costs. The increased retirement plan costs in 2016 were largely due to lower than expected returns on plan assets in 2015.

Interest Expense and Other Variances - The following items contributed to (increased) decreased interest expense and other as follows (in millions):

2017 vs. 2016:	Alliant Energy	IPL	WPL
Higher interest expense primarily due to higher average outstanding long-term debt balances (Refer to Note 9(b) for details)	($19)	($9)	($2)
Higher (lower) equity income from ATC Investment (a)	3	—	(39)
Higher (lower) AFUDC primarily due to increased (decreased) CWIP balances (b)	(13)	(21)	8
Other	2	—	(1)
	($27)	($30)	($34)

2016 vs. 2015:	Alliant Energy	IPL	WPL
Higher (lower) interest expense primarily due to higher (lower) average outstanding long-term debt balances	($9)	($6)	$1
Higher AFUDC primarily due to increased CWIP balances (b)	26	24	2
Other	5	—	4
	$22	$18	$7

(a) Alliant Energy's increase was primarily due to return on equity complaint reserves recorded in 2016, partially offset by a reserve established in 2017 for an anticipated future refund to be made to ATC's customers. WPL's decrease was due to the transfer of its investment in ATC to ATI on December 31, 2016. Refer to Note 6(a) for details.
(b) Changes in AFUDC were primarily due to AFUDC recognized for Marshalltown.

Income Taxes - Refer to Note 11 for details of effective income tax rates for continuing operations.

STRATEGIC OVERVIEW

Strategic Plan - The strategic plan focuses on creating customer value across IPL's and WPL's service territories. Customers have evolving expectations and access to increasingly competitive alternatives for energy. As a result, providing customized energy solutions, while aggressively managing customer prices, remains at the center of the strategic plan. Alliant Energy, IPL and WPL are focused on delivering reliable and affordable electricity with lower electric generation CO2 emissions. By adopting a long-term strategy independent of changing policies and political landscape, Alliant Energy, IPL and WPL remain flexible on environmental compliance plans, while ensuring their electric supply provides economic and sustainable value to their customers and service territories. The strategic plan is evaluated through the integrated resource planning process, subject to review and approval by regulatory agencies and Alliant Energy's Board of Directors. Successful implementation of the strategic plan is expected to result in increased earnings for Alliant Energy, IPL and WPL while limiting cost increases for IPL's and WPL's customers. The strategic plan is built upon two key elements: Growth and Optimization.

Growth - The growth element of the strategic plan includes accelerating the growth of customers' electric and gas usage and expanding the portfolio of energy resources by adding cleaner and renewable energy, with a focus on long-term generation solutions. Increasing electric and gas usage in IPL's and WPL's service territories is expected to help minimize individual customer prices. Expanding cleaner and renewable energy is part of Alliant Energy's long-term plan to reduce fossil-fueled EGU CO2 emissions and may also help support customers' electric usage sustainability efforts.

Accelerate Electric and Gas Usage Growth - Actions to accelerate the growth of customers' electric and gas usage include: retention and growth of current customers, as well as growth of new customers; economic development opportunities designed to attract new customers (e.g. industrial park expansions); and efforts to promote additional markets for electricity and gas, such as the electrification of the transportation sector (e.g. electric vehicles and charging stations).

To help support retention and growth of current customers, the strategic plan focuses on promoting energy efficiency and using new and existing technologies and customized energy solutions, which are expected to help reduce energy costs, provide flexibility, increase productivity, and focus on responding to customers' increased interest in energy-related sustainability initiatives.

Economic development across Iowa and Wisconsin is focused on attracting new businesses by providing planning resources and energy solutions that encourage companies to invest in IPL's and WPL's service territories. For example, the Big Cedar Industrial Center is a 1,300 acre rail-served manufacturing and industrial site in Cedar Rapids, Iowa. This ready-to-build site is in close proximity to regional airport and interstate freeways and offers access to IPL's electric services. IPL has also identified various other development-ready sites, including Prairie View Industrial Center, a 730 acre site in Ames, Iowa;

Indianhead South, a 145 acre site in Mason City, Iowa; and Helgerson Flats Industrial Center, an 80 acre site in Ottumwa, Iowa. WPL is also exploring development-ready sites in Wisconsin.

In addition, investments are expected to be made to extend various gas distribution systems in IPL's and WPL's service territories to serve new customer demand for natural gas.

Expand Cleaner and Renewable Energy - The expansion of cleaner and renewable energy contributes to a more diverse energy portfolio and over the long-term, reduces emissions from EGUs. Alliant Energy is expanding its renewable generation portfolio with the planned expansion of up to 1,200 MW of wind generation at IPL and WPL in aggregate. In addition, Alliant Energy completed construction of Marshalltown in 2017 and is currently constructing West Riverside, which are highly efficient natural gas-fired combined-cycle EGUs. IPL and WPL have also completed various solar projects, and have plans to construct additional solar generation at Marshalltown and West Riverside, respectively. These new generation projects are expected to increase customer access to low-cost energy resources, and also support the retirement of various older, smaller and less efficient coal-fired EGUs, resulting in Alliant Energy reducing its CO2 emissions. These new generation projects and EGU retirements also support a cleaner electricity supply portfolio, which may assist with Alliant Energy's customers' increasing sustainability efforts.

Optimization - The second key element of the strategic plan focuses resources on providing reliable electric and natural gas service to customers in IPL's and WPL's service territories in a cost effective manner through continued modernization of the power grid and gas distribution system, and optimization of the generation fleet. Modernizing, upgrading and optimizing the distribution and generation assets are expected to maximize the value of Alliant Energy's existing infrastructure, strengthen and enhance the safety of its systems, expand customer options with smart technology, and be more price-competitive and market-responsive for customers. For example, customer engagement initiatives include new pricing options and enhanced communication through mobile devices for customers. In addition, IPL and WPL are working with their respective regulatory commissions to determine the appropriate treatment for Tax Reform impacts, which are currently expected to be utilized for future customer benefits.

Alliant Energy is modernizing the power grid to accommodate a growing two-way flow of electricity and information. This includes targeted investments to replace and upgrade aging infrastructure in the electric distribution system. This also includes investments in advanced metering infrastructure, which support the integration of new technologies, as well as improve the security, reliability and resiliency of the power grid.

Since 2010, Alliant Energy has retired or fuel-switched approximately 40% of its older, smaller, less efficient and more costly coal-fired EGUs, and has made investments in its newer, more efficient coal-fired EGUs. Additionally, Alliant Energy has retired or fuel-switched approximately 75% of its combustion turbines and oil-fired EGUs. Alliant Energy is also investing in responsive and cost-effective natural gas-fired generation, which complements its growing investments in renewable energy. These investments are expected to help reduce costs and provide competitively-priced electricity for customers.

Generation Plans - A diversified fuel mix for EGUs is important to meeting the energy needs of customers and also recognizes the importance of using resources in efficient and environmentally responsible ways for the benefit of future generations. The current strategic plan includes the following portfolio of energy resources:

- Natural gas - operating, constructing, and/or converting to, natural gas-fired EGUs.
- Renewables - operating wind farms, solar projects and hydroelectric generators, as well as developing future wind sites and solar projects.
- PPAs - purchasing electricity to meet a portion of customers' demand for electricity, including wind, solar power and nuclear generation PPAs.
- Coal - completing the installation of remaining environmental controls at newer, larger and more efficient coal-fired EGUs, and fuel switching at, and retirement of, certain older, smaller and less efficient coal-fired EGUs.

Increasing levels of energy produced by natural gas-fired EGUs, wind farms and other renewable energy resources, and installing environmental controls at the more efficient coal-fired EGUs, result in significant environmental benefits. As a result of these efforts, mercury emissions have been reduced by approximately 95% from 2005 levels. In addition, SO2 and NOx emissions are currently targeted to be reduced by approximately 90% and 80%, respectively, from 2005 levels by 2020. Electric generation CO2 emissions are currently targeted to be reduced by approximately 40% from 2005 levels by 2030. Water withdrawals at fossil-fueled EGUs are currently targeted to be reduced by approximately 75% from 2005 levels by 2030.

Alliant Energy, IPL and WPL are currently evaluating the types of capacity and energy additions they will pursue to meet their customers' long-term electricity needs, with a focus on clean, reliable and affordable energy, and are monitoring several related external factors that could influence those evaluations. Some of the external factors impacting these plans include regulatory policies and decisions; changes in long-term projections of customer demand; changing customer demand for renewable energy; availability and cost effectiveness of different generation and emission reduction technologies; developments related to environmental regulations; settlements reached with environmental agencies and citizens groups; forward market prices for fossil fuels and electricity; market conditions for obtaining financing; developments related to federal and state renewable portfolio standards; environmental requirements, such as any future requirements relating to GHG emissions or renewable energy sources; and federal and state tax incentives. Environmental compliance plans have also been developed to ensure cost effective compliance with current and proposed environmental laws and regulations impacting existing EGUs. Refer to "Environmental Matters" for details of current and proposed environmental regulations and requirements.

Natural Gas-Fired Generation -

IPL's Construction of Marshalltown - In 2013, the IUB issued an order approving a siting certificate and establishing rate-making principles for IPL's construction of the 706 MW natural gas-fired combined-cycle EGU in Marshalltown, Iowa, referred to as Marshalltown. IPL's construction of Marshalltown began in 2014 and the EGU was placed into service in April 2017. Marshalltown replaces energy and capacity being eliminated with the 2017 and 2018 retirements of Sutherland Units 1 and 3, Fox Lake Units 1 and 3, Burlington Combustion Turbines Units 1-4, Dubuque Units 3 and 4, Centerville Combustion Turbines Units 1 and 2, Grinnell Combustion Turbines Units 1 and 2, and Red Cedar Combustion Turbine Unit 1, which in aggregate had a nameplate capacity of approximately 480 MW.

ITC constructed the majority of the required transmission network upgrades for Marshalltown and elected to pursue an option under the terms of MISO's Attachment "X" tariff to self-fund these transmission network upgrades. As a result, ITC has incurred the capital expenditures to construct the transmission network upgrades and has started billing IPL a direct charge for such transmission network upgrade costs.

Refer to Note 3 for further discussion of Marshalltown.

WPL's Construction of West Riverside - In 2016, WPL received an order from the PSCW authorizing WPL to construct an approximate 730 MW natural gas-fired combined-cycle EGU in Beloit, Wisconsin, referred to as West Riverside. WPL's construction of West Riverside began in 2016 and the EGU is currently expected to be placed in service by early 2020. WPL's estimated portion of capital expenditures is currently expected to be approximately $640 million. The capital expenditures include costs to construct the EGU and a pipeline to supply natural gas to the EGU, and exclude transmission network upgrades and AFUDC. West Riverside will replace energy and capacity being eliminated with the 2015 retirements of Nelson Dewey Units 1 and 2 and Edgewater Unit 3, and the planned retirements of Edgewater Unit 4 and the Rock River and Sheepskin Combustion Turbine Units, which in aggregate have a nameplate capacity of approximately 700 MW.

WPL entered into agreements with neighboring utilities and electric cooperatives that provide each of the neighboring utilities and electric cooperatives options to purchase a partial ownership interest in West Riverside. The purchase price for such options is based on the ownership interest acquired and the net book value of West Riverside on the date of the purchase. The exercise of each option is subject to PSCW approval, and the timing and ownership amounts of the options are as follows:

Counterparty	Option Amount	Option Timing
Wisconsin Public Service Corporation (WPSC)	Up to 200 MW (no more than 100 MW to be acquired in first two years) (a)	2020-2024 (b)
Madison Gas and Electric Company (MGE)	Up to 50 MW (no more than 25 MW to be acquired in first two years)	2020-2025 (b)
Electric cooperatives	Approximately 65 MW	During construction of the EGU

(a) If WPSC exercises its options, WPL may exercise reciprocal options, subject to approval by the PSCW, to purchase up to 200 MW of any natural-gas combined-cycle EGU that either WPSC or its affiliated utility, Wisconsin Electric Power Company (Wisconsin Electric), places in service within 10 years of the date West Riverside is placed in service.
(b) Assumes an in-service date by early 2020.

WPSC and MGE Options - In conjunction with the agreements WPL entered into with WPSC and MGE associated with West Riverside, WPL also entered into amendments to the Columbia joint operating agreement. In November 2016, WPL received an order from the PSCW approving amendments to the Columbia joint operating agreement, which allow WPSC and MGE to forgo certain capital expenditures at Columbia. Based on the additional capital expenditures WPL currently expects to incur through June 1, 2020, WPL's ownership interest in Columbia is expected to increase from 46.2% (as of December 31, 2016) to 53.4%. Refer to Note 4 for further discussion of these amendments.

Renewable Generation Joint Development Agreement - In 2016, WPL, Wisconsin Electric and WPSC executed a separate joint development agreement for the purpose of cooperatively developing any renewable resources greater than 50 MW in Wisconsin for the benefit of their respective customers. The agreement has a 10-year term beginning June 1, 2016, and the utility that originates such renewable resource would hold a majority ownership and operational control of the renewable resource. The other two utilities would have the right to acquire a minority interest in the other utility's renewable resource. Refer to "WPL's Expansion of Wind Generation" below for discussion of definitive agreements entered into by WPL, WPSC and MGE to acquire the assets of FWEC, which is a 129 MW wind farm located in Wisconsin.

Electric Cooperatives' Options - In October 2017, WPL received an order from the PSCW authorizing various electric cooperatives, which currently have wholesale power supply agreements with WPL, to acquire approximately 65 MW of West Riverside while the EGU is being constructed. As part of the electric cooperatives' acquisitions, which were finalized in January 2018, the current wholesale power supply agreements with the various electric cooperatives were extended by at least four years until 2026 with automatic continuation of such agreements unless terminated by either party, with a five-year notice requirement.

Wind Generation - The strategic plan includes the planned expansion of up to 1,200 MW of wind generation in aggregate (up to 1,000 MW at IPL and up to 200 MW at WPL). IPL and WPL believe their respective planned expansion of wind generation will qualify for the full level of production tax credits as a result of progress payments in 2016 for wind turbines, and plan to place these wind projects into service by the end of 2020. The amount and timing of these wind projects will largely depend on regulatory approvals, federal and state tax incentives and the acquisition of wind sites. Estimated capital expenditures for the planned wind generation projects for 2018 through 2020 are included in the "Renewable projects" line in the construction and acquisition expenditures table in "Liquidity and Capital Resources."

IPL's Expansion of Wind Generation - In October 2016, IPL received approval from the IUB for up to 500 MW of new wind generation. In August 2017, IPL filed an application with the IUB for advance rate-making principles for up to 500 MW of additional wind generation, and a decision from the IUB is currently expected in the first quarter of 2018. The advance rate-making principles approved by the IUB in October 2016 and requested by IPL in the August 2017 application were as follows:

- Additional wind generation that qualifies for the full level of production tax credits, as long as the projects are located in Iowa. The October 2016 IUB approval has a cost cap of $1,830/kilowatt, including AFUDC and transmission costs, and the August 2017 application has a cost cap of $1,780/kilowatt, including AFUDC and transmission costs. Any costs incurred in excess of the respective cost cap are expected to be incorporated into rates if determined to be reasonable and prudent.
- A depreciable life of the wind generation facilities of 40 years, unless changed as a result of a contested case before the IUB.
- An 11.0% return on common equity, with the exception of certain transmission facilities classified as intangible assets, which would earn the rate of return on common equity the IUB finds reasonable in each future retail electric rate proceeding.
- A return on common equity for the calculation of AFUDC during the construction period that is the greater of 10.0% or whatever percentage the IUB finds reasonable during IPL's most recent retail electric rate proceeding.
- The application of double leverage is deferred until a future retail electric rate proceeding.
- Amortization over a 10-year period of IPL's prudently incurred and unreimbursed costs, effective with IPL's next retail electric base rate proceeding, if IPL cancels the construction of the wind generation facilities.

IPL currently has on-going, new wind project development as follows:

Wind Site	Nameplate Capacity	Location
Upland Prairie	Up to 300 MW	Clay and Dickinson Counties, Iowa
Whispering Willow	Up to 200 MW	Franklin County, Iowa
English Farms	Up to 170 MW	Poweshiek County, Iowa

IPL continues to explore other development opportunities for its planned expansion of wind generation.

WPL's Expansion of Wind Generation - In October 2017, WPL, along with WPSC and MGE, entered into definitive agreements, subject to regulatory approval, to acquire the assets of FWEC, which is a 129 MW wind farm located in Wisconsin. WPL currently expects to acquire 55 MW of FWEC for approximately $74 million. In November 2017, WPL filed for approval from the PSCW to acquire the assets of FWEC, and a decision from the PSCW is currently expected in the first half of 2018. In January 2018, FERC approved WPL's request to acquire the assets of FWEC. WPL, WPSC and MGE have been receiving electricity from FWEC under PPAs since FWEC began commercial operations in 2008. Upon completion of the acquisitions, such PPAs will terminate.

WPL currently expects to file for approval from the PSCW for the remaining portion of its wind expansion plan in the first half of 2018.

Franklin County Wind Farm - Refer to Note 3 for discussion of the transfer of the 99 MW Franklin County wind farm assets from AEF to IPL in April 2017.

Solar Generation - In 2016, WPL began providing customers with energy from the 2.3 MW Rock River solar project through a 10-year PPA. The solar field is located at WPL's Rock River landfill site in Beloit, Wisconsin. In 2017, IPL installed approximately 5 MW of solar arrays in Dubuque, Iowa. In addition, IPL and WPL have plans to construct solar generation at Marshalltown and West Riverside, respectively.

Coal-Fired Generation -
Environmental Controls Projects - The strategic plan includes adding environmental controls at newer, larger and more efficient coal-fired EGUs to continue producing affordable energy for customers and to benefit the environment. Current projects include installing SCRs at IPL's Ottumwa Unit 1 and WPL's Columbia Unit 2 to achieve compliance obligations under CSAPR and the Consent Decrees. SCR is a post-combustion process that injects ammonia or urea into the stream of gases leaving the EGU boiler to convert NOx emissions into nitrogen and water. The use of a catalyst enhances the effectiveness of the conversion, enabling NOx emissions reductions of up to 90%. Refer to Note 16(e) for discussion of the Consent Decrees.

IPL - Under Iowa law, IPL is required to file an EPB biennially. Filing of periodic reports regarding the implementation of IPL's compliance plan and related budget identified in an EPB is also currently required under a settlement agreement between IPL and the Iowa Office of Consumer Advocate, among others. An EPB provides a utility's compliance plan and related budget for managing regulated emissions from its coal-fired EGUs in a cost-effective manner. IUB approval of an EPB demonstrates that the EPB is reasonably expected to achieve cost-effective compliance with applicable state environmental requirements. In May 2017, the IUB approved IPL's most recent emissions plan and budget, which includes the SCR for Ottumwa Unit 1. The SCR at Ottumwa Unit 1 is currently expected to be placed in service in 2018. IPL's portion of capital expenditures (past and future) for the SCR is expected to be $60 million to $70 million.

WPL - WPL must file a CA application and receive authorization from the PSCW to proceed with any individual environmental controls project with an estimated project cost of $10.7 million or more. WPL is currently constructing the SCR at Columbia Unit 2 pursuant to a 2015 PSCW order and expects to place it in service in 2018. WPL's portion of capital expenditures (past and future) for the SCR is expected to be $40 million to $50 million.

Plant Retirements and Fuel Switching - In 2017, IPL retired Sutherland Units 1 and 3, Dubuque Units 3 and 4, Fox Lake Units 1 and 3, and various other units, as well as fuel switched Prairie Creek Unit 4 from coal to natural gas and Marshalltown Combustion Turbine Units 1-3 from oil to natural gas. The current strategic plan includes the retirement, or fuel switch from coal to natural gas, of several older, smaller and less efficient EGUs in the next several years. The plan includes the following EGUs, with net book values as of December 31, 2017 (dollars in millions; Combustion Turbine (CT)). Refer to "Properties" in Item 2 for additional details, including nameplate capacity.

IPL			WPL		
EGU	Expected Action	Net Book Value	EGU	Expected Action	Net Book Value
Red Cedar CT Unit 1	Retire by 6/1/18	$3	Edgewater Unit 4	Retire by 9/30/18	$33
Burlington CT Units 1-4	Retire by 6/1/18	—	Rock River CT Units 3-6	Retire by 12/31/20	1
Burlington Unit 1	Fuel switch by 12/31/21	60	Sheepskin CT Unit 1	Retire by 12/31/20	—
Prairie Creek Units 1 and 3	Fuel switch or retire by 12/31/25	89			

Alliant Energy, IPL and WPL are working with MISO, state regulatory commissions and other regulatory agencies, as required, to determine the final timing of these actions. The expected dates for the retirement and fuel switching of these EGUs are subject to change depending on operational, regulatory, market and other factors. The potential retirement of other EGUs within the generation fleet continues to be evaluated.

Electric and Gas Distribution Systems - The strategic plan includes investments targeted at replacing, modernizing and upgrading infrastructure in the electric and gas distribution systems. Estimated capital expenditures for expected and current electric and gas distribution infrastructure projects for 2018 through 2021 are included in the "Electric and gas distributions systems" lines in the construction and acquisition expenditures table in "Liquidity and Capital Resources."

Gas Pipeline Expansion - IPL and WPL currently expect to make investments to extend various gas distribution systems to provide natural gas to unserved or underserved areas in their service territories. For example, in March 2017, IPL placed into service the Clinton natural gas pipeline, located in Scott and Clinton Counties in Iowa, which provides capacity for anticipated customer growth in Clinton County.

Pipeline and Hazardous Materials Safety Administration - In April 2016, the Pipeline and Hazardous Materials Safety Administration published proposed regulations to update safety requirements for gas transmission pipelines, which would add new assessment and repair criteria for gas pipelines, and require a systematic approach to verify a pipeline's maximum allowable operating pressure. Given that the Pipeline and Hazardous Materials Safety Administration has not finalized these gas transmission regulations, Alliant Energy, IPL and WPL are currently unable to predict with certainty the impact of these regulations on their financial condition and results of operations. In anticipation of these pending rule changes, Alliant Energy, IPL and WPL have started proactively replacing certain of IPL's transmission pipelines and making modifications to certain of WPL's transmission pipelines.

Advanced Metering Infrastructure (AMI) - IPL currently plans to install AMI in its electric and gas service territories in Iowa through a phased approach from 2017 through 2019. AMI is a system of meters, communications networks and data management systems that enables two-way communication between utilities and its customers. AMI allows for remote meter reading, automatic outage notification, and remote disconnects and reconnects. AMI technology is expected to enhance the communication infrastructure in Alliant Energy's service territories, improve customer service, enhance energy management initiatives and provide operational savings through increased efficiencies.

Non-utility Operations - The strategic plan for Alliant Energy's non-utility operations involves maintaining a modest portfolio of businesses that are accretive to earnings and cash flows. The non-utility strategic plan continues to evolve through exploration of modest investment opportunities within and outside of Alliant Energy's service territories.

RATE MATTERS

Overview - IPL and WPL are subject to federal regulation by FERC, which has jurisdiction over wholesale electric rates and certain natural gas facilities, and state regulation in Iowa and Wisconsin for retail utility rates and standards of service. Such regulatory oversight also covers IPL's and WPL's plans for construction and financing of new EGUs and related activities.

Retail Base Rate Filings - Base rate changes reflect both returns on additions to infrastructure and recovery of changes in costs incurred or expected to be incurred. Given that a portion of the rate changes will offset changes in costs, revenues from rate changes should not be expected to result in an equal change in net income for either IPL or WPL.

IPL's Retail Electric Rate Review (2016 Test Year) - In April 2017, IPL filed a request with the IUB to increase annual electric base rates for its Iowa retail electric customers and interim rates were implemented effective April 13, 2017. In September 2017, IPL reached a partial, non-unanimous settlement agreement with the Iowa Office of Consumer Advocate, the Iowa Business Energy Coalition and the Large Energy Group. In February 2018, the IUB issued an order approving the settlement. Final rates are currently expected to be effective in the first half of 2018 once all motions for reconsideration have been addressed and final tariffs have been approved by the IUB. The requested interim and final rate increases were calculated based on the following (Return on Common Equity (ROE)):

	Interim Rates	Final Rates
Annual retail electric base rate increase	$102 million	$130 million
Regulatory capital structure:		
Common equity	49.1%	49.0%
Long-term debt	46.3%	46.8%
Preferred equity	4.6%	4.2%
After-tax weighted-average cost of capital:		
Marshalltown (ROE - 11.0%)	8.1%	8.0%
Emery (ROE - 12.23%)	8.7%	8.6%
Whispering Willow - East (ROE - 11.7%)	8.4%	8.3%
Other (ROE - 9.6%) (a)	7.4%	7.3%
Retail electric rate base (b)	$3.8 billion	$4.0 billion

(a) Other ROE of 9.6% for interim rates reflects the application of double leverage. Prior to application of double leverage, Other ROE for interim rates was 10.0%. Other ROE of 9.6% for final rates does not reflect the application of double leverage.
(b) The retail electric rate base for interim rates includes post-test year capital additions placed in service prior to the rate filing in April 2017, including Marshalltown and the Franklin County wind farm. The retail electric rate base for final rates also includes deferred tax assets for production tax credits generated by Whispering Willow - East and post-test year capital additions placed in service by September 30, 2017.

Refer to Note 2 for discussion of IPL's initial request, interim rates, settlement and final rates, as well as details for a write-down of regulatory assets recorded by IPL in 2017 related to the settlement.

WPL's Retail Electric and Gas Rate Review (2017/2018 Test Period) - In December 2016, WPL received an order from the PSCW authorizing WPL to implement an increase in annual retail electric rates of $9 million, or approximately 1%, and an increase in annual retail gas rates of $9 million, or approximately 13%. The $9 million net annual retail electric rate increase reflects a $60 million increase in base rates, partially offset by a $51 million reduction in fuel-related costs, using an estimate for 2017 fuel-related costs. These increases are effective January 1, 2017 and extend through the end of 2018. The increases reflect recovery of the costs for environmental controls projects at Edgewater and Columbia, and investments in electric and gas distribution systems, including expansion of natural gas pipeline infrastructure. These rate increases were partially offset by utilization of amounts that WPL previously over-recovered from its customers for energy efficiency cost recovery and electric transmission cost recovery, as well as amounts deferred under the earnings sharing mechanism for the 2013/2014 Test Period. The order included a return on common equity of 10.0% and continues an earnings sharing mechanism, whereby WPL must defer a portion of its earnings and return this amount to its retail electric and gas customers if its annual regulatory return on common equity exceeds 10.25% during the 2017 and 2018 Test Period. WPL must defer 50% of its excess earnings between 10.25% and 11.00%, and 100% of any excess earnings above 11.00%. As of December 31, 2017, WPL has not deferred any 2017 earnings for this provision. Refer to Note 7 for details of WPL's regulatory limitation on distributions of common stock dividends to its parent company in 2018.

The order reflected the impact of the transfer of WPL's investment in ATC to ATI on December 31, 2016 as discussed in Note 6(a), approved changes to depreciation rates pursuant to a September 2016 PSCW order, continued escrow treatment of transmission and energy conservation charges, and application of AFUDC rates to 100% of the retail portion of the CWIP balances for West Riverside. The order also requires deferral of any potential changes in revenue requirement due to anticipated increases in WPL's ownership share of Columbia resulting from the West Riverside agreements WPL previously entered into with neighboring utilities. As of December 31, 2017, WPL's deferral amount related to such provision was not material. The order also approved changes to retail rates, which result in a higher percentage of costs being recovered from customers through fixed and demand charges.

WPL's Retail Electric and Gas Rate Review (2015/2016 Test Period) - Refer to Note 2 for details of a July 2014 PSCW order, which included a provision that required WPL to defer a portion of its earnings if its annual regulatory return on common equity exceeded 10.65% during 2015 and 2016. As of December 31, 2017, Alliant Energy and WPL deferred $5 million of WPL's 2016 earnings for this provision, which WPL currently expects will be refunded to its customers in a future rate review or other proceeding.

IPL's 2014 Retail Electric Rate Settlement Agreement - The IUB approved a settlement agreement in 2014 related to rates charged to IPL's Iowa retail electric customers. The settlement agreement extended IPL's Iowa retail electric base rates authorized in its 2009 Test Year rate review through 2016 and provided targeted retail electric customer billing credits of $105 million in aggregate. In 2016, 2015 and 2014, IPL recorded $9 million, $24 million and $72 million of such credits, respectively.

WPL's Retail Fuel-related Rate Filings - Refer to Note 2 for discussion of WPL's retail fuel-related rate filings for Test Years 2016 through 2018.

Tax Reform - In January 2018, the IUB issued an order initiating investigation of the impacts of Tax Reform. The order requires IPL and other investor-owned utilities in Iowa to track all calculated differences since January 1, 2018 resulting from Tax Reform, such that any over-collections can be refunded to its customers at a future date, if appropriate. In January 2018, the PSCW issued an order directing WPL and other investor-owned utilities in Wisconsin to defer and to accrue carrying costs on the revenue requirement impacts resulting from Tax Reform since its inception. IPL and WPL are working with the IUB and PSCW, respectively, to determine the amount and appropriate mechanism to provide these benefits to their customers. Refer to Note 11 for further discussion of customer benefits related to Tax Reform.

Depreciation Studies - In September 2016, the PSCW issued an order approving the implementation of updated depreciation rates for WPL effective January 1, 2017 as a result of a recently completed depreciation study. The September 2016 PSCW order also authorized WPL to recover the remaining net book value of Edgewater Unit 4 over a 10-year period beginning the later of the retirement date of the EGU or January 1, 2019. In December 2016, FERC issued an order approving the implementation and inclusion of the updated depreciation rates in WPL's wholesale formula rates effective January 1, 2017.

Refer to Note 1(e) for discussion of the IUB's February 2018 order approving the implementation of updated depreciation rates for IPL, which are currently expected to be effective in the first half of 2018, as a result of a recently completed depreciation study.

IPL's Tax Benefit Riders - The IUB has approved electric and gas tax benefit riders proposed by IPL, which utilize regulatory liabilities generated from tax benefits and rate-making accounting changes to credit bills of IPL's Iowa retail electric customers (beginning in 2011) and gas customers (beginning in 2013) to help offset the impact of rate increases on such customers. IPL's tax benefit riders regulatory liability account has been, and plans to be, utilized to credit bills of Iowa retail electric and gas customers as follows (in millions):

	Electric	Gas	Total
Regulatory liability account balance approved by IUB	$520	$55	$575
2011 through 2017 customer billing credits	(509)	(53)	(562)
Regulatory liability benefits recorded in 2017 from rate-making accounting change	16	1	17
Tax Reform adjustment recorded in 2017	(5)	—	(5)
2018 customer billing credits (estimate)	(19)	(3)	(22)
Remaining balance available for future periods	$3	$—	$3

Refer to Notes 2 and 11 for additional discussion of the impacts of the electric and gas tax benefit riders on Alliant Energy's and IPL's regulatory assets and regulatory liabilities, income tax expense and effective income tax rates, as well as impacts from Tax Reform.

Planned Utility Rate Reviews -

IPL's Retail Gas Rate Review (2017 Test Year) - IPL currently expects to make a retail gas rate filing in the second quarter of 2018 based on a 2017 historical Test Year. The key drivers for the anticipated filing include recovery of capital projects, partially offset by the benefits of Tax Reform. Any rate changes are expected to be implemented in two phases with interim rates effective approximately 10 days after the filing and final rates effective after IUB approval. The IUB must decide on requests for retail rate changes within 10 months of the date of the application for which changes are filed, or the interim rates granted become permanent.

WPL's Retail Electric and Gas Rate Review (2019/2020 Test Period) - WPL currently expects to make a retail electric and gas rate filing in the second quarter of 2018 for the 2019/2020 Test Period. The key drivers for the anticipated filing include recovery of capital projects, offset by the benefits of Tax Reform and fuel-related cost savings. Any rate changes granted from this request are expected to be effective on January 1, 2019. WPL currently expects a decision from the PSCW regarding this rate filing by the end of 2018.

Rate Review Details - Details related to IPL's and WPL's key jurisdictions were as follows (Common Equity (CE); Preferred Equity (PE); Long-term Debt (LD); Short-term Debt (SD)):

Jurisdictions	Test Period/Year	Authorized Return on Common Equity (a)	Regulatory Capital Structure				After-tax WACC	Average Rate Base (in millions)
			CE	PE	LD	SD		
IPL:								
Iowa retail (IUB):								
Electric:								
Marshalltown	2016	11.00%	49.0%	4.2%	46.8%	N/A	7.99%	$597 (b)
Emery	2016	12.23%	49.0%	4.2%	46.8%	N/A	8.59%	197 (b)
Whispering Willow - East	2016	11.70%	49.0%	4.2%	46.8%	N/A	8.33%	213 (b)
Other	2016	9.60%	49.0%	4.2%	46.8%	N/A	7.30%	3,020 (b)
Gas (c)	2011	9.56%	48.8%	5.0%	46.2%	N/A	7.76%	255 (b)
Wholesale electric (FERC) (d)	2017	10.97%	48.3%	4.0%	47.7%	N/A	7.75%	141 (e)
WPL:								
Wisconsin retail (PSCW):								
Electric	2018	10.00%	52.2%	N/A	45.2%	2.6%	7.59%	2,851 (f)
Gas	2018	10.00%	52.2%	N/A	45.2%	2.6%	7.59%	284 (f)
Wholesale electric (FERC) (g)	2017	10.90%	55.0%	N/A	45.0%	N/A	8.30%	274 (e)

(a) Authorized returns on common equity may not be indicative of actual returns earned or projections of future returns.
(b) Average rate base was calculated using balances as of the end of the test year, adjusted for post-test year capital additions placed in service by September 30 following the end of the test year.
(c) Authorized returns on common equity and after-tax WACC reflect application of double leverage pursuant to the unanimous settlement agreement approved in the IUB's November 2012 order. Prior to the application of double leverage, authorized return on common equity was 10.0% and after-tax WACC was 8.0%.
(d) IPL's wholesale formula rates reflect annual changes in CE, PE, LD, WACC and estimated rate base, effective July 1, 2018.
(e) Wholesale average rate base reflects production-related rate base calculated as the simple average of the beginning of the test year and end of the test year balances in accordance with the respectively approved formula rates.
(f) Average rate base amounts do not include CWIP or a cash working capital allowance and were calculated using a forecasted 13-month average for the test period. The PSCW provides a return on selected CWIP and a cash working capital allowance by adjusting the percentage return on rate base.
(g) WPL's wholesale formula rates reflect annual changes in WACC and rate base, which includes the wholesale jurisdictional share impacted by the departure of a wholesale customer in 2017.

ENVIRONMENTAL MATTERS

Overview - Alliant Energy, IPL and WPL are subject to regulation of environmental matters by federal, state and local authorities as a result of their current and past operations. Alliant Energy, IPL and WPL monitor these environmental matters and address them by installing controls that reduce emissions and by implementing operational modifications or other measures to address compliance obligations. There is currently significant regulatory uncertainty with respect to a number of environmental rules and regulations discussed below. Given the dynamic nature of environmental regulations and other related regulatory requirements, Alliant Energy, IPL and WPL have compliance plans to address these environmental obligations. Prudent expenditures incurred by IPL and WPL to comply with environmental requirements would likely be recovered in rates from their customers. Refer to "Strategic Overview" for details of environmental compliance plans. The following are major environmental matters that could potentially have a significant impact on financial condition and results of operations.

Air Quality - The CAA and its amendments mandate preservation or enhancement of air quality through existing regulations and periodic reviews to ensure adequacy of the CAA provisions based on scientific data. As part of the basic framework under the CAA, the EPA is required to establish NAAQS, which serve to protect public health and welfare. These standards address six "criteria" pollutants, four of which (NOx, SO2, particulate matter and ozone) are particularly relevant to electric utility operations. Ozone is not directly emitted from EGUs; however, NOx emissions may contribute to its formation in the atmosphere. Fine particulate matter may also be formed in the atmosphere from SO2 and NOx emissions. Alliant Energy, IPL and WPL also maintain compliance with additional emissions standards that apply under the CAA regulatory framework beyond NAAQS. The specific federal and state air quality rules that may materially affect future operations are listed in the table below. Refer to the sections below the following table for detailed discussion of these air quality rules.

Environmental Rule	Emissions Regulated	Alliant Energy's Primary Facilities Potentially Affected	Actual/Anticipated Compliance Deadline
CSAPR	SO2, NOx	Fossil-fueled EGUs over 25 MW capacity in IA and WI	Phase I - 2015; Phase II - 2017
CAA Section 111(d)	CO2	Existing fossil-fueled EGUs over 25 MW capacity	Phase I - 2022-2029; Phase II - 2030
CAA Section 111(b)	CO2	IPL's Marshalltown facility and WPL's West Riverside facility	Upon startup of EGU

Refer to "Properties" in Item 2 for a list of IPL's and WPL's EGUs by primary fuel type that they currently own or operate, as well as discussion of various EGUs that may be retired or changed from coal-fired to an alternative fuel source in the future.

CSAPR - CSAPR is a regional SO2 and NOx cap-and-trade program, where compliance with emission limits may be achieved by purchasing emission allowances and/or reducing emissions through changes in operations or the additions of environmental controls. CSAPR emission allowances may be banked for future year compliance. CSAPR establishes state-specific annual SO2 and NOx emission caps and ozone season NOx emission caps. Compliance with CSAPR emission limits began in 2015, with additional emission limits reductions beginning in 2017. Alliant Energy, IPL and WPL are currently in compliance with applicable CSAPR emission limits. Alliant Energy, IPL and WPL will continue to monitor legal and regulatory developments related to CSAPR and currently expect to continue meeting the existing CSAPR compliance requirements.

GHG Emissions - There is continued debate regarding the public policy response that the U.S. should adopt to address climate change, involving both domestic actions and international efforts. In 2007, the Supreme Court provided direction on the EPA's authority to regulate GHG and ruled that these emissions are covered by the CAA. In 2009, the EPA issued a ruling that found GHG emissions contribute to climate change, and therefore, threaten public health and welfare, which was the prerequisite for implementing carbon reduction standards under the CAA. While the EPA's rules to regulate GHG issued under the authority of the CAA remain subject to further review, growing awareness of climate change is driving efforts to decarbonize the environment through voluntary emissions reductions. The primary GHG emitted from Alliant Energy's, IPL's and WPL's utility operations is CO2 from the combustion of fossil fuels at their larger EGUs. Refer to "Strategic Overview" for discussion of Alliant Energy's, IPL's and WPL's voluntary target to reduce CO2 emissions, as well as their long-term strategy to meet the energy needs of customers while recognizing the importance of using resources in efficient and environmentally responsible ways.

Clean Air Act Section 111(d) - In 2015, the EPA published final standards under Section 111(d) of the CAA, referred to as the Clean Power Plan, which establish guidelines for states to follow in developing plans to reduce CO2 emissions from existing fossil-fueled EGUs. In 2016, the Supreme Court issued a stay of the Clean Power Plan, which placed implementation of the final standards on hold indefinitely. The EPA is currently expected to publish a proposed Clean Power Plan replacement, as well as repeal the original Clean Power Plan, in 2018. Litigation related to the Clean Power Plan is suspended while the EPA proceeds with its repeal and replacement rulemaking processes. Alliant Energy, IPL and WPL are currently unable to predict with certainty the final outcome of the Clean Power Plan, or the impact of the final compliance requirements on their financial condition and results of operations, but expect that expenditures to comply with such requirements could be significant.

Clean Air Act Section 111(b) - In 2015, the EPA published final standards under Section 111(b) of the CAA, which establish CO2 emissions limits for certain new fossil-fueled EGUs. Marshalltown and West Riverside are subject to the EPA's Section 111(b) regulation and have been designed to achieve compliance with these standards. Litigation related to Section 111(b) is suspended while the EPA proceeds with an administrative review of Section 111(b). Given the EPA's Section 111(b) rulemaking remains subject to the EPA's review, Alliant Energy, IPL and WPL are currently unable to predict with certainty the impact of these standards.

In addition, in order for the EPA to regulate existing fossil-fueled EGUs under Section 111(d) of the CAA, the EPA must have valid regulation of new fossil-fueled EGUs under Section 111(b) of the CAA. If Section 111(b) is vacated, the EPA's ability to implement regulations for CO2 emissions at existing fossil-fueled EGUs, as well as any future Clean Power Plan replacement rule, could be limited.

WPL Consent Decree - Refer to Note 16(e) for discussion of a Consent Decree approved by the U.S. District Court for the Western District of Wisconsin in 2013 and WPL's obligations thereunder. The Consent Decree resolves a notice of violation issued by the EPA in 2009 and complaints filed by the Sierra Club in 2010 regarding alleged air permitting violations at Columbia, Edgewater and Nelson Dewey.

IPL Consent Decree - Refer to Note 16(e) for discussion of a Consent Decree approved by the U.S. District Court for the Northern District of Iowa in 2015 and IPL's obligations thereunder. The Consent Decree resolves potential CAA issues associated with emissions from IPL's coal-fired generating facilities in Iowa.

Water Quality -
Effluent Limitation Guidelines - In 2015, the EPA published final effluent limitation guidelines, which are expected to require changes to discharge limits for wastewater from certain IPL and WPL steam generating facilities. Compliance with the final guidelines for existing steam generating facilities is determined by each facility's wastewater discharge permit, and will be required by December 31, 2023. Effective January 2016, compliance for new steam generating facilities is required immediately upon operation. Projects required for compliance with these guidelines are facility specific. Alliant Energy, IPL and WPL currently believe the expenditures to comply with these guidelines could be significant.

Land and Solid Waste -
Coal Combustion Residuals Rule - The final CCR Rule, which regulates CCR as a non-hazardous waste, was published and became effective in 2015. IPL and WPL have seven and three coal-fired EGUs, respectively, with coal ash ponds that are impacted by this rule. In addition, IPL and WPL have three and two active CCR landfills, respectively, that are impacted by this rule. Actual costs resulting from the CCR Rule may be different than the amounts recorded due to potential changes in compliance strategies that will be used, as well as other potential cost estimate changes. Expenditures incurred by IPL and WPL to comply with the CCR Rule are anticipated to be recovered in rates from their customers.

MGP Sites - Refer to Note 16(e) for discussion of IPL's and WPL's MGP sites.

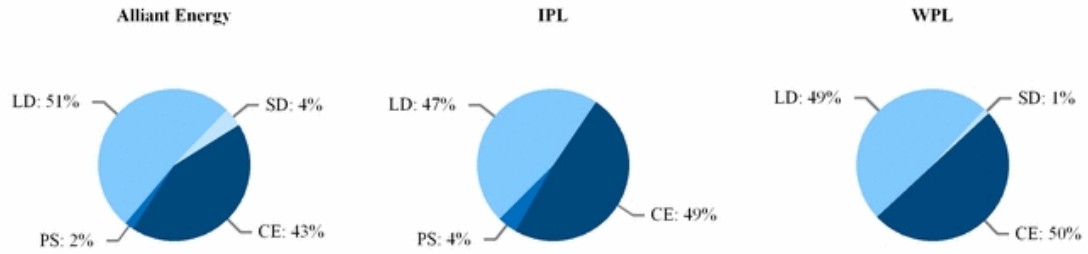
Other - Refer to Note 16(e), Item 1 Business, "Strategic Overview" and "Liquidity and Capital Resources" for further discussion of environmental matters, including discussion of specific projects and the associated estimated capital expenditures.

LIQUIDITY AND CAPITAL RESOURCES

Overview - Alliant Energy, IPL and WPL expect to maintain adequate liquidity to operate their businesses and implement their strategic plan as a result of operating cash flows generated by their utility business, and available capacity under a single revolving credit facility and IPL's sales of accounts receivable program, supplemented by periodic issuances of long-term debt and Alliant Energy equity securities.

Liquidity Position - At December 31, 2017, Alliant Energy had $28 million of cash and cash equivalents, $680 million ($105 million at the parent company, $250 million at IPL and $325 million at WPL) of available capacity under the single revolving credit facility and $92 million of available capacity at IPL under its sales of accounts receivable program. Refer to "Short-term Debt" below and Note 9(a) for further discussion of the credit facility. Refer to Note 5(b) for additional information on IPL's sales of accounts receivable program.

Capital Structure - Alliant Energy, IPL and WPL plan to maintain debt-to-total capitalization ratios that are consistent with investment-grade credit ratings. IPL and WPL expect to maintain capital structures consistent with their authorized levels. Alliant Energy expects to maintain consolidated debt at approximately 55% of total capital and consolidated preferred stock at less than 10% of total capital. These targets may be adjusted depending on subsequent developments and the impact on their respective WACC and investment-grade credit ratings. Capital structures as of December 31, 2017 were as follows (Common Equity (CE); IPL's Preferred Stock (PS); Long-term Debt (including current maturities) (LD); Short-term Debt (SD)):



Alliant Energy, IPL and WPL intend to manage their capital structures and liquidity positions in such a way that facilitates their ability to raise the necessary funds reliably and on reasonable terms and conditions, while maintaining capital structures consistent with those approved by regulators. In addition to capital structures, other important factors used to determine the characteristics of future financings include financial coverage ratios, capital spending plans, regulatory orders and rate-making considerations, levels of debt imputed by rating agencies, market conditions, the impact of tax initiatives and legislation, and anticipated proceeds from asset sales. The PSCW factors certain imputed debt adjustments in establishing a regulatory capital structure as part of WPL's retail rate reviews. The IUB does not make any explicit adjustments for imputed debt in establishing capital ratios used in determining customer rates, although such adjustments are considered by IPL in recommending an appropriate capital structure. The most significant debt imputations by rating agencies or state regulators relate to the DAEC PPA, pension and OPEB obligations and the sales of accounts receivable program.

Credit and Capital Markets - Alliant Energy, IPL and WPL are aware of the potential implications that credit and capital market disruptions might have on their ability to raise external funding required for their respective operations and capital expenditure plans. Alliant Energy, IPL and WPL maintain a single revolving credit facility to provide backstop liquidity to their commercial paper programs, and ensure a committed source of liquidity in the event the commercial paper market becomes disrupted. In addition, IPL maintains a sales of accounts receivable program as an alternative financing source.

Primary Sources and Uses of Cash - Alliant Energy's most significant source of cash is from electric and gas sales to IPL's and WPL's customers. Cash from these sales reimburses IPL and WPL for prudently-incurred expenses to provide service to their utility customers and provides IPL and WPL a return of and a return on the assets used to provide such services. Utility operating cash flows are expected to cover IPL's and WPL's capital expenditures required to maintain their current infrastructure and dividends paid to Alliant Energy's shareowners. Capital needed to retire debt and fund capital expenditures related to large strategic projects is expected to be met primarily through external financings.

Tax Reform - In December 2017, Tax Reform was enacted. The net impacts of re-measuring deferred taxes associated with regulated utility operations were recorded in regulatory assets and regulatory liabilities and will be utilized to provide benefits to customers in the future. Alliant Energy, IPL and WPL are awaiting decisions from state and federal regulators regarding the timing, amount and method of delivering net tax benefits from utility operations to its utility customers; however, impacts from these decisions may include changes in cash flow from operations, credit ratings, liquidity, and capital needs. Alliant Energy, IPL and WPL are currently unable to quantify these impacts. Refer to Note 11 for further discussion of Tax Reform.

Cash Flows - Selected information from the cash flows statements was as follows (in millions):

	Alliant Energy			IPL			WPL		
	2017	2016	2015	**2017**	2016	2015	**2017**	2016	2015
Cash and cash equivalents, January 1	**$8.2**	$5.8	$56.9	**$3.3**	$4.5	$5.3	**$4.2**	$0.4	$46.7
Cash flows from (used for):									
Operating activities	**983.4**	859.6	871.2	**440.0**	361.9	385.0	**465.7**	521.4	449.8
Investing activities	**(1,496.3)**	(1,186.5)	(919.2)	**(706.4)**	(693.6)	(511.9)	**(665.7)**	(478.9)	(358.2)
Financing activities	**532.6**	329.3	(3.1)	**266.7**	330.5	126.1	**218.9**	(38.7)	(137.9)
Net increase (decrease)	**19.7**	2.4	(51.1)	**0.3**	(1.2)	(0.8)	**18.9**	3.8	(46.3)
Cash and cash equivalents, December 31	**$27.9**	$8.2	$5.8	**$3.6**	$3.3	$4.5	**$23.1**	$4.2	$0.4

Operating Activities - The following items contributed to increased (decreased) operating activity cash flows (in millions):

2017 vs. 2016	Alliant Energy	IPL	WPL
Higher collections at IPL due to interim retail electric base rate increase effective April 13, 2017	$77	$77	$—
Higher collections at WPL due to new retail electric and gas base rates in 2017	72	—	72
Changes in cash collateral balances	30	—	—
Timing of WPL's fuel-related cost recoveries from customers	(50)	—	(50)
Changes in the level of cash proceeds from IPL's sales of accounts receivable	(25)	(25)	—
Lower distributions received at WPL from its investment in ATC due to the transfer of the investment in ATC to ATI on December 31, 2016	—	—	(27)
Changes in income taxes paid/refunded	(1)	20	(36)
Other (primarily due to other changes in working capital)	21	6	(15)
	$124	$78	($56)

2016 vs. 2015	Alliant Energy	IPL	WPL
Decreased collections from IPL's retail customers due to increased past due amounts	($33)	($33)	$—
Changes in cash collateral balances	(27)	—	—
Changes in income taxes paid/refunded	(10)	(30)	35
Changes in the level of cash proceeds from IPL's sales of accounts receivable	33	33	—
Timing of WPL's fuel-related cost recoveries from customers	17	—	17
Changes in collections at IPL from higher revenues from retail electric customer billing credits related to the approved retail electric base rate freeze through 2016	15	15	—
Other (includes other changes in working capital largely related to changes in inventory levels)	(7)	(8)	20
	($12)	($23)	$72

Income Tax Payments and Refunds - Income tax (payments) refunds were as follows (in millions):

	2017	2016	2015
IPL	**$9**	($11)	$19
WPL	**(8)**	28	(7)
Other subsidiaries	**(12)**	(27)	(12)
Alliant Energy	**($11)**	($10)	$—

Alliant Energy, IPL and WPL currently do not expect to make any significant federal income tax payments through 2024 based on their current federal net operating loss and credit carryforward positions. While no significant federal income tax payments through 2024 are expected to occur, some tax payments and refunds may occur for state taxes and between consolidated group members (including IPL and WPL) under the tax sharing agreement between Alliant Energy and its subsidiaries. Refer to Note 11 for discussion of the carryforward positions.

Pension Plan Contributions - Alliant Energy, IPL and WPL currently do not expect to make any significant pension plan contributions in 2018 based on the funded status and assumed return on assets for each plan as of the December 31, 2017 measurement date. Refer to Note 12(a) for discussion of the current funded levels of pension plans.

Investing Activities - The following items contributed to increased (decreased) investing activity cash flows (in millions):

2017 vs. 2016	Alliant Energy	IPL	WPL
Lower (higher) utility construction expenditures (a)	($151)	$14	($184)
Non-utility wind investment in Oklahoma (Refer to Note 6(a) for details)	(98)	—	—
Proceeds from the liquidation of company-owned life insurance policies in 2016	(31)	(19)	—
Other	(30)	(8)	(3)
	($310)	($13)	($187)

2016 vs. 2015	Alliant Energy	IPL	WPL
Higher utility construction expenditures (b)	($171)	($70)	($109)
Proceeds from IPL's Minnesota distribution asset sales in 2015 (Refer to Note 3 for details)	(140)	(140)	—
Proceeds from the liquidation of company-owned life insurance policies in 2016	31	19	—
Other	13	9	(12)
	($267)	($182)	($121)

(a) Largely due to higher expenditures for WPL's West Riverside facility, IPL's and WPL's electric and gas distribution systems and IPL's expansion of wind generation, partially offset by lower expenditures for IPL's Marshalltown facility.
(b) Largely due to higher expenditures for IPL's expansion of wind generation, IPL's and WPL's electric and gas distribution systems, and WPL's West Riverside facility, partially offset by lower expenditures for IPL's Marshalltown facility and environmental controls projects at WPL's Edgewater Unit 5.

Construction and Acquisition Expenditures - Construction and acquisition expenditures and financing plans are reviewed, approved and updated as part of the financial planning processes. Changes may result from a number of reasons, including regulatory requirements, changing legislation, not obtaining favorable and acceptable regulatory approval on certain projects, improvements in technology, improvements to ensure reliability of the electric and gas distribution systems, and new opportunities. Alliant Energy, IPL and WPL have not yet entered into contractual commitments relating to the majority of their anticipated future construction and acquisition expenditures. As a result, they have some discretion with regard to the level and timing of these expenditures. The table below summarizes anticipated construction and acquisition expenditures (in millions). Cost estimates represent Alliant Energy's, IPL's and WPL's portion of total escalated construction expenditures and exclude AFUDC and capitalized interest, if applicable. Such estimates reflect impacts to Alliant Energy's and WPL's capital expenditures resulting from purchase options by certain electric cooperatives for a partial ownership interest in West Riverside, as well as additional capital expenditures related to Columbia that WPL is expected to incur related to agreements entered into with WPSC and MGE. Refer to "Strategic Overview" for further discussion of certain key projects impacting construction and acquisition plans related to the utility business.

	Alliant Energy				IPL				WPL			
	2018	2019	2020	2021	2018	2019	2020	2021	2018	2019	2020	2021
Generation:												
Renewable projects	$655	$850	$140	$85	$565	$725	$50	$85	$90	$125	$90	$—
West Riverside	225	90	10	—	—	—	—	—	225	90	10	—
Other	140	95	150	140	60	50	80	75	80	45	70	65
Distribution:												
Electric systems	440	435	485	560	260	250	290	345	180	185	195	215
Gas systems	130	95	90	115	75	50	55	65	55	45	35	50
Other	130	110	125	100	25	20	25	20	10	10	10	10
	$1,720	$1,675	$1,000	$1,000	$985	$1,095	$500	$590	$640	$500	$410	$340

Financing Activities - The following items contributed to increased (decreased) financing activity cash flows (in millions):

2017 vs. 2016	Alliant Energy	IPL	WPL
Lower payments to retire long-term debt	$309	$—	$—
Higher net proceeds from common stock issuances	123	—	—
Net changes in the amount of commercial paper outstanding and other short-term borrowings outstanding	87	—	(60)
Higher (lower) net proceeds from issuance of long-term debt	(250)	(50)	300
Higher capital contributions from IPL's and WPL's parent company, Alliant Energy	—	10	30
Other (includes higher dividend payments in 2017)	(66)	(24)	(12)
	$203	($64)	$258

2016 vs. 2015	Alliant Energy	IPL	WPL
Proceeds from long-term debt issued in 2016 (Refer to "Long-term Debt" below)	$800	$300	$—
Payments to retire long-term debt in 2015 (Refer to "Long-term Debt" below)	181	150	31
Net changes in the amount of commercial paper outstanding	66	—	13
Payments to retire long-term debt in 2016 (Refer to "Long-term Debt" below)	(310)	—	—
Proceeds from long-term debt issued in 2015 (Refer to "Long-term Debt" below)	(250)	(250)	—
Lower net proceeds from common stock issuances	(125)	—	—
Higher capital contributions from IPL's and WPL's parent company, Alliant Energy	—	25	60
Other (includes higher dividend payments in 2016)	(30)	(21)	(5)
	$332	$204	$99

FERC and Public Utility Holding Company Act Financing Authorizations - Under the Public Utility Holding Company Act of 2005, FERC has authority over the issuance of utility securities, except to the extent that a public utility's primary state regulatory commission has retained jurisdiction over such matters. FERC currently has authority over the issuance of securities by IPL. FERC does not have authority over the issuance of securities by Alliant Energy, WPL, AEF or Corporate Services.

In November 2017, IPL received authorization, and has current remaining authority, from FERC through December 31, 2019 for the following (in millions):

Long-term debt securities issuances in aggregate	$1,100
Short-term debt securities outstanding at any time (including borrowings from its parent)	300
Preferred stock issuances in aggregate	300

State Regulatory Financing Authorizations - In August 2017, WPL received authorization from the PSCW to have up to $400 million of short-term borrowings and/or letters of credit outstanding at any time through the earlier of the expiration date of WPL's credit facility agreement (including extensions) or December 2024. In December 2016, WPL received authorization from the PSCW to issue up to $1 billion of long-term debt securities in aggregate during 2017 through 2019, with no more than $650 million to be issued in any year. WPL's current remaining authority for issuances of long-term debt securities is $700 million in aggregate through 2019.

Shelf Registrations - Alliant Energy, IPL and WPL have current shelf registration statements on file with the SEC for availability to issue unspecified amounts of securities through December 2020. Alliant Energy's shelf registration statement may be used to issue common stock, debt and other securities. IPL's and WPL's shelf registration statements may be used to issue preferred stock and debt securities.

Common Stock Dividends - Payment of common stock dividends is subject to dividend declaration by Alliant Energy's Board of Directors. Alliant Energy's general long-term goal is to maintain a dividend payout ratio that is competitive with the industry average. Based on that, Alliant Energy's goal is to maintain a dividend payout ratio of approximately 60% to 70% of consolidated earnings from continuing operations. IPL's and WPL's goal is to maintain dividend payout ratios of approximately 65% to 75%. Alliant Energy's, IPL's and WPL's dividend payout ratios were 63%, 72% and 67% of their consolidated earnings from continuing operations in 2017, respectively. Refer to "Executive Overview" for discussion of expected common stock dividends in 2018. Refer to Note 7 for discussion of IPL's and WPL's dividend payment restrictions based on the terms of applicable regulatory limitations and IPL's outstanding preferred stock.

Common Stock Issuances - Refer to Note 7 for discussion of common stock issuances by Alliant Energy in 2015 through 2017. Refer to "Executive Overview" for discussion of expected issuances of common stock in 2018.

Short-term Debt - In August 2017, Alliant Energy, IPL and WPL entered into a single new revolving credit facility agreement, which expires in August 2022, to provide short-term borrowing flexibility and backstop liquidity for commercial paper outstanding. As of December 31, 2017, the short-term borrowing capacity totaled $1 billion ($400 million for Alliant Energy at the parent company level, $250 million for IPL and $350 million for WPL). There are currently 13 lenders that participate in the credit facility, with aggregate respective commitments ranging from $20 million to $130 million. The credit facility includes a $100 million letter of credit commitment and $50 million swingline commitment, which are available to each of Alliant Energy, IPL and WPL. Subject to certain conditions, Alliant Energy, IPL and WPL may each reallocate and change its sublimit up to $500 million, $400 million and $500 million, respectively, within the $1 billion total commitment. Subject to certain conditions, Alliant Energy, IPL and WPL may exercise two extension options, each extending the maturity date by one year. The credit facility has a provision to expand the facility size up to an additional $300 million, for a potential total commitment of $1.3 billion, subject to lender approval for Alliant Energy and subject to lender and regulatory approvals for IPL and WPL.

The credit agreement contains provisions that prohibit placing liens on any of the property of Alliant Energy, IPL or WPL or their respective subsidiaries with certain exceptions. Exceptions include among others, liens to secure obligations of up to 10% of the consolidated tangible assets of the applicable borrower (valued at carrying value), liens imposed by government entities, materialmen's and similar liens, judgment liens, liens to secure additional non-recourse debt not to exceed $100 million outstanding at any one time at each of Alliant Energy, IPL and WPL, and purchase money liens.

The credit agreement contains provisions that require, during its term, any proceeds from asset sales, with certain exclusions, in excess of 25% of Alliant Energy's, IPL's and WPL's respective consolidated assets be used to reduce certain of their respective debt commitments. Exclusions include, among others, certain sale and lease-back transactions, sales of non-utility assets, intercompany asset sales and sales of certain contracts and accounts receivable.

The credit agreement contains customary events of default, including a cross-default provision that would be triggered if Alliant Energy or certain of its significant subsidiaries (including IPL and WPL) defaults on debt (other than non-recourse debt) totaling $100 million or more. IPL and WPL are subject to a similar cross-default provision with respect to their own respective consolidated debt. A default by Alliant Energy or its non-utility subsidiaries would not trigger a cross-default at IPL or WPL, nor would a default by either of IPL or WPL constitute a cross-default event for the other. If an event of default under the credit agreement occurs and is continuing, then the lenders may declare any outstanding obligations of the defaulting borrower under the credit agreement immediately due and payable. In addition, if any order for relief is entered under bankruptcy laws with respect to (a) Alliant Energy, IPL or WPL, then any outstanding obligations of Alliant Energy under the credit agreement would be immediately due and payable, or (b) IPL or WPL, then any outstanding obligations of IPL or WPL, respectively, under the credit agreement would be immediately due and payable.

A material adverse change representation is not required for borrowings under the credit agreement.

Refer to Note 9(a) for discussion of financial covenants required under the credit agreement, as well as additional information on the credit facility, commercial paper outstanding and AEF's $95 million, 364-day variable-rate term loan credit agreement related to the acquisition of an equity ownership interest in a non-utility wind farm located in Oklahoma. At December 31, 2017, Alliant Energy, IPL and WPL were in compliance with financial covenants of the credit agreement.

Long-term Debt - Refer to Note 9(b) for discussion of IPL's and WPL's issuances of long-term debt in 2017. Significant issuances of long-term debt in 2016 and 2015 were as follows (dollars in millions):

Company	Principal Amount	Type	Interest Rate	Maturity Date	Use of Proceeds
2016:					
AEF	$500	Variable-rate term loan credit agreement	2% at December 31, 2017	Oct-2018	Retire borrowings under Alliant Energy's and Franklin County Holdings LLC's variable-rate term loan credit agreements that matured in 2016, reduce outstanding commercial paper and for general corporate purposes
IPL	300	Senior debentures	3.7%	Sep-2046	Reduce cash amounts received from its sales of accounts receivable program, reduce commercial paper classified as long-term debt and for general corporate purposes
2015:					
IPL	250	Senior debentures	3.4%	Aug-2025	Reduce commercial paper classified as long-term debt, reduce cash amounts received from its sales of accounts receivable program and for general corporate purposes

AEF's $500 million term loan credit agreement (with Alliant Energy as guarantor) includes substantially the same covenants and events of default included in the revolving credit facility financial covenants discussed above and in Note 9(a). At December 31, 2017, Alliant Energy was in compliance with financial covenants of the term loan credit agreement.

There were no significant retirements of long-term debt in 2017. Significant retirements of long-term debt in 2016 and 2015 were as follows (dollars in millions):

Company	Principal Amount	Type	Interest Rate	Retirement Date
2016:				
Alliant Energy	$250	Variable-rate term loan credit agreement	1% at December 31, 2015	Oct-2016
Franklin County Holdings LLC	60	Variable-rate term loan credit agreement	1% at December 31, 2015	Oct-2016
2015:				
IPL	150	Senior debentures	3.3%	Jun-2015
WPL	16	Pollution control revenue bonds	5%	Sep-2015
WPL	15	Pollution control revenue bonds	5.375%	Aug-2015

Refer to Note 9(b) for further discussion of long-term debt and "Executive Overview" for discussion of expected issuances of long-term debt in 2018.

Impact of Credit Ratings on Liquidity and Collateral Obligations -
Ratings Triggers - The long-term debt of Alliant Energy and its subsidiaries is not subject to any repayment requirements as a result of explicit credit rating downgrades or so-called "ratings triggers." However, Alliant Energy and its subsidiaries are parties to various agreements that contain provisions dependent on credit ratings. In the event of a significant downgrade, Alliant Energy or its subsidiaries may need to provide credit support, such as letters of credit or cash collateral equal to the amount of the exposure, or may need to unwind the contract or pay the underlying obligation. In the event of a significant downgrade, management believes Alliant Energy, IPL and WPL have sufficient liquidity to cover counterparty credit support or collateral requirements under these various agreements. In addition, a downgrade in the credit ratings of Alliant Energy, IPL or WPL, including those that may result from the impacts of Tax Reform, could also result in them paying higher interest rates in future financings, reduce flexibility with future financing plans, reduce their pool of potential lenders, increase their borrowing costs under existing credit facilities or limit their access to the commercial paper market. Credit ratings and outlooks as of the date of this report are as follows:

		Standard & Poor's Ratings Services	Moody's Investors Service
Alliant Energy:	Corporate/issuer	A-	Baa1
	Commercial paper	A-2	P-2
	Senior unsecured long-term debt	N/A	N/A
	Outlook	Stable	Stable
IPL:	Corporate/issuer	A-	Baa1
	Commercial paper	A-2	P-2
	Senior unsecured long-term debt	A-	Baa1
	Preferred stock	BBB	Baa3
	Outlook	Stable	Stable
WPL:	Corporate/issuer	A	A2
	Commercial paper	A-1	P-1
	Senior unsecured long-term debt	A	A2
	Outlook	Stable	Stable

Credit ratings are not recommendations to buy or sell securities and are subject to change, and each rating should be evaluated independently of any other rating. Each of Alliant Energy, IPL or WPL assumes no obligation to update their respective credit ratings. Refer to Note 15 for additional information on ratings triggers for commodity contracts accounted for as derivatives.

Off-Balance Sheet Arrangements -
Special Purpose Entities - IPL maintains a Receivables Agreement whereby it may sell its customer accounts receivables, unbilled revenues and certain other accounts receivables to a third party through wholly-owned and consolidated special purpose entities. The purchase commitment from the third party to which IPL sells its receivables expires in March 2018. IPL currently expects to amend and extend the purchase commitment. In 2017, 2016 and 2015, IPL evaluated the third party that purchases IPL's receivable assets under the Receivables Agreement and believes that the third party is a VIE. However, IPL concluded consolidation of the third party was not required.

In addition, IPL's sales of accounts receivable program agreement contains a cross-default provision that is triggered if IPL or Alliant Energy incurs an event of default on debt totaling $50 million or more. If an event of default under IPL's sales of accounts receivable program agreement occurs, then the counterparty could terminate such agreement. Refer to Note 5(b) for additional information regarding IPL's sales of accounts receivable program.

Guarantees and Indemnifications - At December 31, 2017, various guarantees and indemnifications are outstanding related to Alliant Energy's cash equity ownership interest in a non-utility wind farm and Alliant Energy's and IPL's prior divestiture activities. Refer to Note 16(d) for additional information.

Certain Financial Commitments -
Contractual Obligations - Consolidated long-term contractual obligations as of December 31, 2017 were as follows (in millions):

Alliant Energy	2018	2019	2020	2021	2022	Thereafter	Total
Other purchase obligations (Note 16(b))	$545	$364	$292	$267	$226	$716	$2,410
Long-term debt maturities (Note 9(b))	856	256	357	8	333	3,093	4,903
Interest - long-term debt obligations	217	184	168	157	157	1,998	2,881
Capital purchase obligations (Note 16(a))	82	—	—	—	—	—	82
Operating leases (Note 10(a))	6	5	2	2	1	13	29
Capital leases	2	1	1	1	—	—	5
	$1,708	$810	$820	$435	$717	$5,820	$10,310

IPL	2018	2019	2020	2021	2022	Thereafter	Total
Other purchase obligations (Note 16(b))	$322	$236	$193	$189	$164	$565	$1,669
Long-term debt maturities (Note 9(b))	350	—	200	—	—	1,875	2,425
Interest - long-term debt obligations	115	91	91	83	83	1,060	1,523
Capital purchase obligations (Note 16(a))	15	—	—	—	—	—	15
Operating leases (Note 10(a))	3	2	1	1	1	13	21
Capital leases	1	—	—	—	—	—	1
	$806	$329	$485	$273	$248	$3,513	$5,654

WPL	2018	2019	2020	2021	2022	Thereafter	Total
Other purchase obligations (Note 16(b))	$222	$126	$96	$78	$62	$151	$735
Long-term debt maturities (Note 9(b))	—	250	150	—	250	1,200	1,850
Interest - long-term debt obligations	89	89	73	69	69	938	1,327
Capital purchase obligations (Note 16(a))	67	—	—	—	—	—	67
Operating leases (Note 10(a))	3	3	1	—	—	—	7
Capital lease - Sheboygan Falls Energy Facility (Note 10(b))	15	15	15	15	15	35	110
Capital leases - other	1	1	1	1	—	—	4
	$397	$484	$336	$163	$396	$2,324	$4,100

At December 31, 2017, Alliant Energy, IPL and WPL had no uncertain tax positions recorded as liabilities. Refer to Note 12(a) for anticipated pension and OPEB funding amounts, which are not included in the above tables. Refer to "Construction and Acquisition Expenditures" above for additional information on construction and acquisition programs. In addition, at December 31, 2017, there were various other liabilities included on the balance sheets that, due to the nature of the liabilities, the timing of payments cannot be estimated and are therefore excluded from the above tables.

OTHER MATTERS

Market Risk Sensitive Instruments and Positions - Primary market risk exposures are associated with commodity prices, investment prices and interest rates. Risk management policies are used to monitor and assist in mitigating these market risks and derivative instruments are used to manage some of the exposures related to commodity prices. Refer to Notes 1(h) and 15 for further discussion of derivative instruments.

Commodity Price - Alliant Energy, IPL and WPL are exposed to the impact of market fluctuations in the price and transportation costs of commodities they procure and market. Established policies and procedures mitigate risks associated with these market fluctuations, including the use of various commodity derivatives and contracts of various durations for the forward sale and purchase of these commodities. Exposure to commodity price risks in the utility businesses is also significantly mitigated by current rate-making structures in place for recovery of fuel-related costs as well as the cost of natural gas purchased for resale. IPL's electric and gas tariffs and WPL's wholesale electric and gas tariffs provide for subsequent monthly adjustments to their tariff rates for material changes in prudently incurred commodity costs. IPL's and WPL's rate mechanisms, combined with commodity derivatives, significantly reduce commodity risk associated with their electric and gas margins.

WPL's retail electric margins have modest exposure to the impact of changes in commodity prices due largely to the current retail recovery mechanism in place in Wisconsin for fuel-related costs. In December 2017, the PSCW approved annual forecasted fuel-related costs per MWh of $26.75 based on $356 million of variable fuel-related costs applicable for retail and wholesale customers for WPL's 2018 Test Period. The retail portion of the 2018 fuel-related costs will be monitored using an annual bandwidth of plus or minus 2%. Based on the cost recovery mechanism in Wisconsin, the annual forecasted fuel-related costs approved by the PSCW in December 2017 and an annual bandwidth of plus or minus 2%, Alliant Energy and WPL currently estimate the commodity risk exposure to their retail electric margins in 2018 is approximately $6 million. However, the commodity risk exposure to WPL's electric margins in 2018 could increase if WPL's return on common equity in 2018 exceeds the most recently authorized return on common equity.

Refer to Note 2 for discussion of WPL's retail fuel-related rate filings for Test Years 2016 through 2018, and Note 1(g) for additional details of utility cost recovery mechanisms that significantly reduce commodity risk.

Investment Price - Alliant Energy, IPL and WPL are exposed to investment price risk as a result of their investments in securities, largely related to securities held by their pension and OPEB plans. Refer to Note 12(a) for details of the securities held by their pension and OPEB plans. Refer to "Critical Accounting Policies and Estimates" for the impact on retirement plan costs of changes in the rate of returns earned by plan assets.

Interest Rate - Alliant Energy, IPL and WPL are exposed to risk resulting from changes in interest rates associated with variable-rate borrowings. In addition, Alliant Energy and IPL are exposed to risk resulting from changes in interest rates on cash amounts outstanding under IPL's sales of accounts receivable program. Assuming the impact of a hypothetical 100 basis point increase in interest rates on variable-rate borrowings and cash proceeds outstanding under IPL's sales of accounts receivable program at December 31, 2017, Alliant Energy's, IPL's and WPL's annual pre-tax expense would increase by approximately $9 million, $0 and $0, respectively. Refer to Notes 5(b) and 9 for additional information on cash proceeds outstanding under IPL's sales of accounts receivable program, and short- and long-term variable-rate borrowings, respectively. Refer to "Critical Accounting Policies and Estimates" for the impacts of changes in discount rates on retirement plan obligations and costs.

New Accounting Standards - Refer to Note 1(n) for discussion of new accounting standards impacting Alliant Energy, IPL and WPL.

Critical Accounting Policies and Estimates - The preparation of financial statements in conformity with GAAP requires management to apply accounting policies and make estimates that affect results of operations and the amounts of assets and liabilities reported in the financial statements. The following accounting policies and estimates are critical to the business and the understanding of financial results as they require critical assumptions and judgments by management. The results of these assumptions and judgments form the basis for making estimates regarding the results of operations and the amounts of assets and liabilities that are not readily apparent from other sources. Actual financial results may differ materially from these estimates. Management has discussed these critical accounting policies and estimates with the Audit Committee of the Board of Directors. Refer to Note 1 for additional discussion of accounting policies and the estimates used in the preparation of the financial statements.

Contingencies - Assumptions and judgments are made each reporting period regarding the future outcome of contingent events. Loss contingency amounts are recorded for any contingent events for which the likelihood of loss is probable and able to be reasonably estimated based upon current available information. The amounts recorded may differ from actuals when the uncertainty is resolved. The estimates made in accounting for contingencies, and the gains and losses that are recorded upon the ultimate resolution of these uncertainties, could have a significant effect on results of operations and the amount of assets and liabilities in the financial statements. Note 16 provides further discussion of contingencies assessed at

December 31, 2017, including various pending legal proceedings, guarantees and indemnifications that may have a material impact on financial condition and results of operations.

Regulatory Assets and Regulatory Liabilities - IPL and WPL are regulated by various federal and state regulatory agencies. As a result, they are subject to GAAP for regulated operations, which recognizes that the actions of a regulator can provide reasonable assurance of the existence of an asset or liability. Regulatory assets or regulatory liabilities arise as a result of a difference between GAAP and actions imposed by the regulatory agencies in the rate-making process. Regulatory assets generally represent incurred costs that have been deferred as such costs are probable of recovery in future customer rates. Regulatory liabilities generally represent obligations to make refunds to customers or amounts collected in rates for which the related costs have not yet been incurred. Regulatory assets and regulatory liabilities are recognized in accordance with the rulings of applicable federal and state regulators, and future regulatory rulings may impact the carrying value and accounting treatment of regulatory assets and regulatory liabilities.

Assumptions and judgments are made each reporting period regarding whether regulatory assets are probable of future recovery and regulatory liabilities are probable future obligations by considering factors such as regulatory environment changes, rate orders issued by the applicable regulatory agencies, historical decisions by such regulatory agencies regarding similar regulatory assets and regulatory liabilities, and subsequent events of such regulatory agencies. The decisions made by regulatory authorities have an impact on the recovery of costs, the rate of return on invested capital and the timing and amount of assets to be recovered by rates. A change in these decisions may result in a material impact on results of operations and the amount of assets and liabilities in the financial statements. Note 2 provides details of the nature and amounts of regulatory assets and regulatory liabilities assessed at December 31, 2017, as well as discussion of a write-down of regulatory assets in 2017 related to the recovery of Sutherland Units 1 and 3, and AROs deemed no longer probable of recovery in future rates, due to the IPL retail electric rate review settlement, which was approved by the IUB in February 2018.

Long-Lived Assets - Periodic assessments regarding the recoverability of certain long-lived assets are completed when factors indicate the carrying value of such assets may be impaired or such assets are planned to be sold. These assessments require significant assumptions and judgments by management. The long-lived assets assessed for impairment generally include certain assets within regulated operations that may not be fully recovered from IPL's and WPL's customers as a result of regulatory decisions in the future, and assets within non-utility operations that are proposed to be sold or are currently generating operating losses.

Regulated Operations - Certain long-lived assets within regulated operations are reviewed for possible impairment whenever events or changes in circumstances indicate all or a portion of the carrying value of the assets may be disallowed for rate-making purposes. If IPL or WPL is disallowed recovery of any portion of the carrying value of its regulated property, plant and equipment that is under construction, has been recently completed or is probable of being retired early, an impairment charge is recognized equal to the amount of the carrying value that was disallowed recovery. If IPL or WPL is disallowed a full or partial return on the carrying value of its regulated property, plant and equipment that is under construction, has been recently completed or is probable of being retired early, an impairment charge is recognized equal to the difference between the carrying amount of the asset and the present value of the future revenues expected from its regulated property, plant and equipment. Alliant Energy's, IPL's and WPL's long-lived assets within their regulated operations that were assessed for impairment and plant abandonment in 2017 included IPL's and WPL's generating units subject to early retirement.

Generating Units Subject to Early Retirement - Alliant Energy, IPL and WPL evaluate future plans for their electric generation fleet and have announced the early retirement of certain older and less-efficient EGUs. When it becomes probable that an EGU will be retired before the end of its useful life, Alliant Energy, IPL and WPL must assess whether the EGU meets the criteria to be considered probable of abandonment. EGUs that are considered probable of abandonment generally have material remaining net book values and are expected to cease operations in the near term significantly before the end of their original estimated useful lives. If an EGU meets such criteria to be considered probable of abandonment, Alliant Energy, IPL and WPL must assess the probability of full recovery of the remaining carrying value of such EGU. If it is probable that regulators will not allow full recovery of and a full return on the remaining net book value of the abandoned EGU, an impairment charge is recognized equal to the difference between the remaining carrying value and the present value of the future revenues expected from the abandoned EGU.

Alliant Energy and WPL concluded that Edgewater Unit 4 met the criteria to be considered probable of abandonment in 2017. WPL is currently allowed a full recovery of and a full return on this EGU from both its retail and wholesale customers, and as a result, Alliant Energy and WPL concluded that no impairment was required as of December 31, 2017. Alliant Energy, IPL and WPL evaluated their other EGUs that are subject to early retirement and determined that no other EGUs met the criteria to be considered probable of abandonment as of December 31, 2017. Refer to "Strategic Overview" for discussion of additional EGUs that may be retired early and could be considered probable of abandonment in future periods, along with the net book value of such EGUs.

Unbilled Revenues - Unbilled revenues are primarily associated with utility operations. Energy sales to individual customers are based on the reading of customers' meters, which occurs on a systematic basis throughout the month. Amounts of energy delivered to customers since the date of the last meter reading are estimated at the end of each reporting period and the corresponding estimated unbilled revenue is recorded. The unbilled revenue estimate is based on daily system demand volumes, estimated customer usage by class, temperature impacts, line losses and the most recent customer rates. Such process involves the use of various judgments and assumptions and significant changes in these judgments and assumptions could have a material impact on results of operations. As of December 31, 2017, unbilled revenues related to Alliant Energy's utility operations were $198 million ($113 million at IPL and $85 million at WPL). Note 5(b) provides discussion of IPL's unbilled revenues as of December 31, 2017 sold to a third party related to its sales of accounts receivable program.

Pensions and Other Postretirement Benefits - Alliant Energy, IPL and WPL sponsor various defined benefit pension and OPEB plans that provide benefits to a significant portion of their employees and retirees. Assumptions and judgments are made periodically to estimate the obligations and costs related to their retirement plans. There are many judgments and assumptions involved in determining an entity's pension and other postretirement liabilities and costs each period including employee demographics (including life expectancies and compensation levels), discount rates, assumed rates of return and funding. Changes made to plan provisions may also impact current and future benefits costs. Judgments and assumptions are supported by historical data and reasonable projections and are reviewed at least annually. The following table shows the impacts of changing certain key actuarial assumptions discussed above (in millions):

	Defined Benefit Pension Plans		OPEB Plans	
Change in Actuarial Assumption	Impact on Projected Benefit Obligation at December 31, 2017	Impact on 2018 Net Periodic Benefit Costs	Impact on Projected Benefit Obligation at December 31, 2017	Impact on 2018 Net Periodic Benefit Costs
Alliant Energy				
1% change in discount rate	$173	$11	$22	$2
1% change in expected rate of return	N/A	9	N/A	1
IPL				
1% change in discount rate	80	5	8	1
1% change in expected rate of return	N/A	4	N/A	1
WPL				
1% change in discount rate	76	6	8	1
1% change in expected rate of return	N/A	4	N/A	—

Note 12(a) provides additional details of pension and OPEB plans.

Income Taxes - Alliant Energy, IPL and WPL are subject to income taxes in various jurisdictions. Assumptions and judgments are made each reporting period to estimate income tax assets, liabilities, benefits and expenses. Judgments and assumptions are supported by historical data and reasonable projections. Significant changes in these judgments and assumptions could have a material impact on financial condition and results of operations. Alliant Energy's and IPL's critical assumptions and judgments for 2017 include estimates of qualifying deductions for repairs expenditures and allocation of mixed service costs due to the impact of Iowa rate-making principles on such property-related differences. Critical assumptions and judgments also include projections of future taxable income used to determine the ability to utilize net operating losses and credit carryforwards prior to their expiration, and accounting for the impacts of Tax Reform.

Effect of Rate-making on Property-related Differences - Alliant Energy's and IPL's effective income tax rates are normally impacted by certain property-related differences at IPL for which deferred tax is not recorded in the income statement pursuant to Iowa rate-making principles. Changes in methods or assumptions regarding the amount of IPL's qualifying repairs expenditures, allocation of mixed service costs, and costs related to retirement or removal of depreciable property could result in a material impact on Alliant Energy's and IPL's financial condition and results of operations. Refer to Note 1(c) for further discussion of regulatory accounting for taxes. Refer to Note 11 for details of how the effect of rate-making on property-related differences impacted Alliant Energy's and IPL's effective income tax rates for 2017, 2016 and 2015.

Carryforward Utilization - Significant federal tax credit carryforwards and federal and state net operating loss carryforwards exist for Alliant Energy, IPL and WPL as of December 31, 2017. Based on projections of current and future taxable income, Alliant Energy, IPL and WPL plan to utilize substantially all of these carryforwards prior to their expiration. Due to the anticipated future reductions in revenues from utility customers due to Tax Reform, Alliant Energy expects a reduction in its future consolidated taxable income, which will extend the period to which prior unutilized operating losses will be utilized. Taxable income must be reduced by net operating losses carryforwards prior to utilizing federal tax credit carryforwards. Alliant Energy expects to utilize its net operating losses carryforwards by 2024 and therefore, currently does not expect to utilize 2002 and 2003 vintage federal credit carryforwards prior to their expiration in 2022 and 2023, respectively. This has resulted in valuation allowance charges recorded to "Income tax expense (benefit)" on the income statements. Federal credit carryforwards generated from 2004 through 2008, which amount to $7 million for Alliant Energy, are expected to be utilized within five years of expiration. All other federal credit carryforwards and federal net operating loss carryforwards are expected to be utilized more than five years before expiration. Changes in tax regulations or assumptions regarding current and future taxable income could require additional valuation allowances in the future resulting in a material impact on financial condition and results of operations. Refer to Note 11 for further discussion of Tax Reform, federal tax credit carryforwards, and federal and state net operating loss carryforwards.

Other Future Considerations - In addition to items discussed earlier in MDA, the Notes in Item 8 and "Risk Factors" in Item 1A, the following items could impact future financial condition or results of operations:

Electric Transmission Service Expense - IPL and WPL currently receive substantially all their transmission services from ITC and ATC, respectively. Due to the use of formula rates that allow ITC and ATC to change the amount they charge to their customers based upon changes to the costs they incur, there is uncertainty regarding the long-term trends of IPL's and WPL's future electric transmission service expense. In 2018, IPL and WPL expect amounts billed by ITC and ATC, respectively, to decrease as a result of anticipated impacts from Tax Reform and MISO transmission owner return on equity complaints. However, based on IPL's and WPL's electric transmission cost recovery mechanisms discussed in Note 1(g), IPL and WPL currently do not expect that any changes to electric transmission service costs billed by ITC and ATC will have a material impact on their financial condition and results of operations. Refer to Note 2 for further discussion of the MISO transmission owner return on equity complaints.

Sales Trends -
Jo-Carroll Energy, Inc. - In 2014, Jo-Carroll Energy, Inc. provided notice of termination of its wholesale power supply agreement with IPL effective April 1, 2018. Sales to Jo-Carroll Energy, Inc. represented 3% of IPL's total electric sales in 2017.

Great Lakes Utilities - In 2014, Great Lakes Utilities provided notice of termination of its wholesale power supply agreement with WPL effective December 31, 2017. Sales to Great Lakes Utilities represented approximately 2% of WPL's total electric sales in 2017.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Quantitative and Qualitative Disclosures About Market Risk are reported in "Other Matters - Market Risk Sensitive Instruments and Positions" in MDA.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareowners of Alliant Energy Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Alliant Energy Corporation and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income, common equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America (U.S.).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (U.S.) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2018, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP
DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 23, 2018

We have served as the Company's auditor since 2002.

ALLIANT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2017	2016	2015
	(in millions, except per share amounts)		
Operating revenues:			
Electric utility	**$2,894.7**	$2,875.5	$2,770.5
Gas utility	**400.9**	355.4	381.2
Other utility	**47.5**	48.6	57.9
Non-utility	**39.1**	40.5	44.0
Total operating revenues	**3,382.2**	3,320.0	3,253.6
Operating expenses:			
Electric production fuel and purchased power	**818.1**	854.0	837.7
Electric transmission service	**480.9**	527.9	485.3
Cost of gas sold	**211.4**	194.3	219.1
Asset valuation charges for Franklin County wind farm	**—**	86.4	—
Other operation and maintenance	**651.0**	606.5	629.5
Depreciation and amortization	**461.8**	411.6	401.3
Taxes other than income taxes	**105.6**	102.3	103.7
Total operating expenses	**2,728.8**	2,783.0	2,676.6
Operating income	**653.4**	537.0	577.0
Interest expense and other:			
Interest expense	**215.6**	196.2	187.1
Equity income from unconsolidated investments, net	**(44.8)**	(39.6)	(33.8)
Allowance for funds used during construction	**(49.7)**	(62.5)	(36.9)
Interest income and other	**(0.5)**	(0.5)	(0.7)
Total interest expense and other	**120.6**	93.6	115.7
Income from continuing operations before income taxes	**532.8**	443.4	461.3
Income taxes	**66.7**	59.4	70.4
Income from continuing operations, net of tax	**466.1**	384.0	390.9
Income (loss) from discontinued operations, net of tax	**1.4**	(2.3)	(2.5)
Net income	**467.5**	381.7	388.4
Preferred dividend requirements of Interstate Power and Light Company	**10.2**	10.2	10.2
Net income attributable to Alliant Energy common shareowners	**$457.3**	$371.5	$378.2
Weighted average number of common shares outstanding (basic and diluted)	**229.7**	227.1	225.4
Earnings per weighted average common share attributable to Alliant Energy common shareowners (basic and diluted):			
Income from continuing operations, net of tax	**$1.99**	$1.65	$1.69
Loss from discontinued operations, net of tax	**—**	(0.01)	(0.01)
Net income	**$1.99**	$1.64	$1.68
Amounts attributable to Alliant Energy common shareowners:			
Income from continuing operations, net of tax	**$455.9**	$373.8	$380.7
Income (loss) from discontinued operations, net of tax	**1.4**	(2.3)	(2.5)
Net income	**$457.3**	$371.5	$378.2

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these statements.

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ALLIANT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2017	2016
	(in millions, except per share and share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	**$27.9**	$8.2
Accounts receivable, less allowance for doubtful accounts	**482.8**	493.3
Production fuel, at weighted average cost	**72.3**	98.1
Gas stored underground, at weighted average cost	**44.5**	37.6
Materials and supplies, at weighted average cost	**105.6**	86.6
Regulatory assets	**84.3**	57.8
Other	**87.7**	95.5
Total current assets	**905.1**	877.1
Property, plant and equipment, net	**11,234.5**	10,279.2
Investments:		
ATC Investment	**274.2**	317.6
Other	**121.9**	20.0
Total investments	**396.1**	337.6
Other assets:		
Regulatory assets	**1,582.4**	1,857.3
Deferred charges and other	**69.7**	22.6
Total other assets	**1,652.1**	1,879.9
Total assets	**$14,187.8**	$13,373.8
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of long-term debt	**$855.7**	$4.6
Commercial paper	**320.2**	244.1
Other short-term borrowings	**95.0**	—
Accounts payable	**477.3**	445.3
Regulatory liabilities	**140.0**	186.2
Other	**260.8**	281.8
Total current liabilities	**2,149.0**	1,162.0
Long-term debt, net (excluding current portion)	**4,010.6**	4,315.6
Other liabilities:		
Deferred tax liabilities	**1,478.4**	2,570.2
Regulatory liabilities	**1,357.2**	494.8
Pension and other benefit obligations	**504.0**	489.9
Other	**306.4**	279.3
Total other liabilities	**3,646.0**	3,834.2
Commitments and contingencies (Note 16)		
Equity:		
Alliant Energy Corporation common equity:		
Common stock - $0.01 par value - 480,000,000 shares authorized; 231,348,646 and 227,673,654 shares outstanding	**2.3**	2.3
Additional paid-in capital	**1,845.5**	1,693.1
Retained earnings	**2,346.0**	2,177.0
Accumulated other comprehensive loss	**(0.5)**	(0.4)
Shares in deferred compensation trust - 463,365 and 441,695 shares at a weighted average cost of $23.91 and $22.71 per share	**(11.1)**	(10.0)
Total Alliant Energy Corporation common equity	**4,182.2**	3,862.0
Cumulative preferred stock of Interstate Power and Light Company	**200.0**	200.0
Total equity	**4,382.2**	4,062.0
Total liabilities and equity	**$14,187.8**	$13,373.8

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these statements.

ALLIANT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017	2016	2015
		(in millions)	
Cash flows from operating activities:			
Net income	**$467.5**	$381.7	$388.4
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	**461.8**	411.6	401.3
Other amortizations	**21.7**	(4.8)	12.4
Deferred tax expense and tax credits	**139.6**	84.6	114.2
Equity income from unconsolidated investments, net	**(44.8)**	(39.6)	(33.8)
Distributions from equity method investments	**38.1**	28.3	30.6
Equity component of allowance for funds used during construction	**(33.6)**	(42.3)	(24.4)
Asset valuation charges for Franklin County wind farm	**—**	86.4	—
Other	**6.7**	0.8	15.7
Other changes in assets and liabilities:			
Accounts receivable	**29.6**	(121.4)	36.8
Sales of accounts receivable	**(9.0)**	16.0	(17.0)
Regulatory assets	**(130.8)**	(3.6)	(104.5)
Regulatory liabilities	**(83.8)**	(63.0)	(67.8)
Deferred income taxes	**81.7**	102.4	94.6
Other	**38.7**	22.5	24.7
Net cash flows from operating activities	**983.4**	859.6	871.2
Cash flows used for investing activities:			
Construction and acquisition expenditures:			
Utility business	**(1,281.8)**	(1,131.2)	(960.3)
Other	**(185.1)**	(65.6)	(74.0)
Proceeds from Minnesota electric and natural gas distribution asset sales	**—**	—	139.9
Other	**(29.4)**	10.3	(24.8)
Net cash flows used for investing activities	**(1,496.3)**	(1,186.5)	(919.2)
Cash flows from (used for) financing activities:			
Common stock dividends	**(288.3)**	(266.5)	(247.3)
Proceeds from issuance of common stock, net	**149.6**	26.6	151.2
Proceeds from issuance of long-term debt	**550.0**	800.0	250.7
Payments to retire long-term debt	**(4.6)**	(313.4)	(183.0)
Net change in commercial paper and other short-term borrowings	**171.1**	84.3	18.5
Other	**(45.2)**	(1.7)	6.8
Net cash flows from (used for) financing activities	**532.6**	329.3	(3.1)
Net increase (decrease) in cash and cash equivalents	**19.7**	2.4	(51.1)
Cash and cash equivalents at beginning of period	**8.2**	5.8	56.9
Cash and cash equivalents at end of period	**$27.9**	$8.2	$5.8
Supplemental cash flows information:			
Cash paid during the period for:			
Interest, net of capitalized interest	**($212.6)**	($192.4)	($184.8)
Income taxes, net	**($11.3)**	($9.8)	$—
Significant non-cash investing and financing activities:			
Accrued capital expenditures	**$196.5**	$154.4	$148.3

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these statements.

ALLIANT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMMON EQUITY

	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Shares in Deferred Compensation Trust	Total Alliant Energy Common Equity
				(in millions)		
2015:						
Beginning balance	$2.2	$1,508.0	$1,938.0	($0.6)	($8.9)	$3,438.7
Net income attributable to Alliant Energy common shareowners			378.2			378.2
Common stock dividends ($1.10 per share)			(247.3)			(247.3)
Common stock issued, net	0.1	151.1				151.2
Other		2.7			0.4	3.1
Other comprehensive income, net of tax				0.2		0.2
Ending balance	2.3	1,661.8	2,068.9	(0.4)	(8.5)	3,724.1
2016:						
Net income attributable to Alliant Energy common shareowners			371.5			371.5
Common stock dividends ($1.175 per share)			(266.5)			(266.5)
Common stock issued, net		26.6				26.6
Other		4.7	3.1		(1.5)	6.3
Ending balance	2.3	1,693.1	2,177.0	(0.4)	(10.0)	3,862.0
2017:						
Net income attributable to Alliant Energy common shareowners			**457.3**			**457.3**
Common stock dividends ($1.26 per share)			**(288.3)**			**(288.3)**
Common stock issued, net		**149.6**				**149.6**
Other		**2.8**			**(1.1)**	**1.7**
Other comprehensive loss, net of tax				**(0.1)**		**(0.1)**
Ending balance	**$2.3**	**$1,845.5**	**$2,346.0**	**($0.5)**	**($11.1)**	**$4,182.2**

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these statements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareowners of Interstate Power and Light Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Interstate Power and Light Company and subsidiary (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income, common equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America (U.S.).

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (U.S.) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP
DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 23, 2018

We have served as the Company's auditor since 2002.

INTERSTATE POWER AND LIGHT COMPANY
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2017	2016	2015
	(in millions)		
Operating revenues:			
Electric utility	**$1,598.9**	$1,569.7	$1,503.8
Gas utility	**226.0**	204.0	217.3
Steam and other	**45.4**	46.7	53.4
Total operating revenues	**1,870.3**	1,820.4	1,774.5
Operating expenses:			
Electric production fuel and purchased power	**443.6**	430.5	428.4
Electric transmission service	**310.4**	359.7	328.2
Cost of gas sold	**115.6**	111.0	123.3
Other operation and maintenance	**403.8**	383.7	389.9
Depreciation and amortization	**245.0**	210.8	207.2
Taxes other than income taxes	**55.0**	53.9	55.6
Total operating expenses	**1,573.4**	1,549.6	1,532.6
Operating income	**296.9**	270.8	241.9
Interest expense and other:			
Interest expense	**112.4**	103.2	96.8
Allowance for funds used during construction	**(31.4)**	(52.0)	(28.2)
Interest income and other	**(0.2)**	(0.3)	(0.2)
Total interest expense and other	**80.8**	50.9	68.4
Income before income taxes	**216.1**	219.9	173.5
Income tax benefit	**(10.9)**	(5.9)	(22.7)
Net income	**227.0**	225.8	196.2
Preferred dividend requirements	**10.2**	10.2	10.2
Earnings available for common stock	**$216.8**	$215.6	$186.0

Earnings per share data is not disclosed given Alliant Energy Corporation is the sole shareowner of all shares of IPL's common stock outstanding during the periods presented.

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these statements.

INTERSTATE POWER AND LIGHT COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2017	2016
	(in millions, except per share and share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	**$3.6**	$3.3
Accounts receivable, less allowance for doubtful accounts	**264.9**	240.7
Production fuel, at weighted average cost	**52.4**	70.3
Gas stored underground, at weighted average cost	**20.3**	16.3
Materials and supplies, at weighted average cost	**60.6**	46.5
Regulatory assets	**41.9**	17.7
Other	**32.3**	27.7
Total current assets	**476.0**	422.5
Property, plant and equipment, net	**5,926.2**	5,435.6
Other assets:		
Regulatory assets	**1,189.7**	1,441.1
Deferred charges and other	**14.1**	5.5
Total other assets	**1,203.8**	1,446.6
Total assets	**$7,606.0**	$7,304.7
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of long-term debt	**$350.0**	$—
Accounts payable	**220.3**	186.3
Accounts payable to associated companies	**50.1**	43.3
Regulatory liabilities	**69.7**	149.6
Accrued taxes	**47.1**	53.8
Other	**90.5**	88.8
Total current liabilities	**827.7**	521.8
Long-term debt, net (excluding current portion)	**2,056.0**	2,153.5
Other liabilities:		
Deferred tax liabilities	**910.7**	1,511.8
Regulatory liabilities	**685.7**	281.2
Pension and other benefit obligations	**173.8**	173.2
Other	**242.4**	214.2
Total other liabilities	**2,012.6**	2,180.4
Commitments and contingencies (Note 16)		
Equity:		
Interstate Power and Light Company common equity:		
Common stock - $2.50 par value - 24,000,000 shares authorized; 13,370,788 shares outstanding	**33.4**	33.4
Additional paid-in capital	**1,797.8**	1,597.8
Retained earnings	**678.5**	617.8
Total Interstate Power and Light Company common equity	**2,509.7**	2,249.0
Cumulative preferred stock	**200.0**	200.0
Total equity	**2,709.7**	2,449.0
Total liabilities and equity	**$7,606.0**	$7,304.7

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these statements.

INTERSTATE POWER AND LIGHT COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017	2016	2015
	(in millions)		
Cash flows from operating activities:			
Net income	**$227.0**	$225.8	$196.2
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	**245.0**	210.8	207.2
Deferred tax expense and tax credits	**55.8**	35.6	28.9
Equity component of allowance for funds used during construction	**(21.1)**	(35.2)	(18.6)
Other	**1.5**	2.9	19.5
Other changes in assets and liabilities:			
Accounts receivable	**(7.9)**	(59.7)	20.4
Sales of accounts receivable	**(9.0)**	16.0	(17.0)
Regulatory assets	**(126.2)**	(54.7)	(76.3)
Accounts payable	**24.0**	8.0	(42.7)
Regulatory liabilities	**(71.2)**	(67.3)	(75.5)
Deferred income taxes	**103.7**	97.7	82.1
Other	**18.4**	(18.0)	60.8
Net cash flows from operating activities	**440.0**	361.9	385.0
Cash flows used for investing activities:			
Construction and acquisition expenditures	**(676.0)**	(689.7)	(619.3)
Proceeds from Minnesota electric and natural gas distribution asset sales	**—**	—	139.9
Other	**(30.4)**	(3.9)	(32.5)
Net cash flows used for investing activities	**(706.4)**	(693.6)	(511.9)
Cash flows from financing activities:			
Common stock dividends	**(156.1)**	(151.9)	(140.0)
Capital contributions from parent	**200.0**	190.0	165.0
Proceeds from issuance of long-term debt	**250.0**	300.0	250.0
Payments to retire long-term debt	**—**	—	(150.0)
Other	**(27.2)**	(7.6)	1.1
Net cash flows from financing activities	**266.7**	330.5	126.1
Net increase (decrease) in cash and cash equivalents	**0.3**	(1.2)	(0.8)
Cash and cash equivalents at beginning of period	**3.3**	4.5	5.3
Cash and cash equivalents at end of period	**$3.6**	$3.3	$4.5
Supplemental cash flows information:			
Cash (paid) refunded during the period for:			
Interest	**($111.8)**	($99.7)	($93.9)
Income taxes, net	**$8.6**	($11.1)	$19.3
Significant non-cash investing and financing activities:			
Accrued capital expenditures	**$76.4**	$53.8	$77.0

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these statements.

INTERSTATE POWER AND LIGHT COMPANY
CONSOLIDATED STATEMENTS OF COMMON EQUITY

	Common Stock	Additional Paid-In Capital	Retained Earnings	Total IPL Common Equity
		(in millions)		
2015:				
Beginning balance	$33.4	$1,242.8	$508.1	$1,784.3
Earnings available for common stock			186.0	186.0
Common stock dividends			(140.0)	(140.0)
Capital contribution from parent		165.0		165.0
Ending balance	33.4	1,407.8	554.1	1,995.3
2016:				
Earnings available for common stock			215.6	215.6
Common stock dividends			(151.9)	(151.9)
Capital contribution from parent		190.0		190.0
Ending balance	33.4	1,597.8	617.8	2,249.0
2017:				
Earnings available for common stock			**216.8**	**216.8**
Common stock dividends			**(156.1)**	**(156.1)**
Capital contribution from parent		**200.0**		**200.0**
Ending balance	**$33.4**	**$1,797.8**	**$678.5**	**$2,509.7**

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these statements.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareowner of Wisconsin Power and Light Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Wisconsin Power and Light Company and subsidiary (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income, equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America (U.S.).

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (U.S.) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP
DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 23, 2018

We have served as the Company's auditor since 2002.

WISCONSIN POWER AND LIGHT COMPANY
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2017	2016	2015
	(in millions)		
Operating revenues:			
Electric utility	**$1,295.8**	$1,305.8	$1,266.7
Gas utility	**174.9**	151.4	163.9
Other	**2.1**	1.9	4.5
Total operating revenues	**1,472.8**	1,459.1	1,435.1
Operating expenses:			
Electric production fuel and purchased power	**374.5**	423.5	409.3
Electric transmission service	**170.5**	168.2	157.1
Cost of gas sold	**95.8**	83.3	95.8
Other operation and maintenance	**249.0**	219.8	235.4
Depreciation and amortization	**212.9**	192.5	184.3
Taxes other than income taxes	**46.9**	44.8	44.5
Total operating expenses	**1,149.6**	1,132.1	1,126.4
Operating income	**323.2**	327.0	308.7
Interest expense and other:			
Interest expense	**93.8**	91.4	92.4
Equity income from unconsolidated investments	**(0.7)**	(39.8)	(35.1)
Allowance for funds used during construction	**(18.3)**	(10.5)	(8.7)
Interest income and other	**(0.1)**	(0.2)	(0.4)
Total interest expense and other	**74.7**	40.9	48.2
Income before income taxes	**248.5**	286.1	260.5
Income taxes	**61.9**	93.3	82.9
Net income	**186.6**	192.8	177.6
Net income attributable to noncontrolling interest	**—**	2.4	1.3
Earnings available for common stock	**$186.6**	$190.4	$176.3

Earnings per share data is not disclosed given Alliant Energy Corporation is the sole shareowner of all shares of WPL's common stock outstanding during the periods presented.

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these statements.

WISCONSIN POWER AND LIGHT COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2017	2016
	(in millions, except per share and share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	**$23.1**	$4.2
Accounts receivable, less allowance for doubtful accounts	**212.2**	226.3
Production fuel, at weighted average cost	**19.9**	27.8
Gas stored underground, at weighted average cost	**24.2**	21.3
Materials and supplies, at weighted average cost	**42.1**	36.3
Regulatory assets	**42.4**	40.1
Prepaid gross receipts tax	**41.3**	39.8
Other	**13.4**	20.7
Total current assets	**418.6**	416.5
Property, plant and equipment, net	**4,917.9**	4,426.7
Other assets:		
Regulatory assets	**392.7**	416.2
Deferred charges and other	**27.3**	30.9
Total other assets	**420.0**	447.1
Total assets	**$5,756.5**	$5,290.3
LIABILITIES AND EQUITY		
Current liabilities:		
Commercial paper	**$25.0**	$52.3
Accounts payable	**201.7**	192.9
Accounts payable to associated companies	**22.2**	34.6
Regulatory liabilities	**70.3**	36.6
Accrued interest	**25.6**	23.6
Other	**51.4**	54.7
Total current liabilities	**396.2**	394.7
Long-term debt, net	**1,833.4**	1,535.2
Other liabilities:		
Deferred tax liabilities	**522.4**	971.6
Regulatory liabilities	**671.5**	213.6
Capital lease obligations - Sheboygan Falls Energy Facility	**70.2**	77.2
Pension and other benefit obligations	**213.7**	207.8
Other	**167.6**	159.4
Total other liabilities	**1,645.4**	1,629.6
Commitments and contingencies (Note 16)		
Equity:		
Wisconsin Power and Light Company common equity:		
Common stock - $5 par value - 18,000,000 shares authorized; 13,236,601 shares outstanding	**66.2**	66.2
Additional paid-in capital	**1,109.0**	1,019.0
Retained earnings	**706.3**	645.6
Total Wisconsin Power and Light Company common equity	**1,881.5**	1,730.8
Total liabilities and equity	**$5,756.5**	$5,290.3

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these statements.

WISCONSIN POWER AND LIGHT COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017	2016	2015
	(in millions)		
Cash flows from operating activities:			
Net income	**$186.6**	$192.8	$177.6
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	**212.9**	192.5	184.3
Other amortizations	**17.7**	(8.7)	5.3
Deferred tax expense and tax credits	**53.9**	114.5	77.6
Other	**(13.3)**	(17.8)	(10.2)
Other changes in assets and liabilities:			
Accounts receivable	**17.7**	(47.6)	3.7
Regulatory assets	**(4.7)**	51.1	(28.2)
Other	**(5.1)**	44.6	39.7
Net cash flows from operating activities	**465.7**	521.4	449.8
Cash flows used for investing activities:			
Construction and acquisition expenditures	**(637.4)**	(453.0)	(344.3)
Other	**(28.3)**	(25.9)	(13.9)
Net cash flows used for investing activities	**(665.7)**	(478.9)	(358.2)
Cash flows from (used for) financing activities:			
Common stock dividends	**(125.9)**	(135.0)	(126.9)
Capital contribution from parent	**90.0**	60.0	—
Proceeds from issuance of long-term debt	**300.0**	—	—
Net change in commercial paper	**(27.3)**	32.4	19.9
Other	**(17.9)**	3.9	(30.9)
Net cash flows from (used for) financing activities	**218.9**	(38.7)	(137.9)
Net increase (decrease) in cash and cash equivalents	**18.9**	3.8	(46.3)
Cash and cash equivalents at beginning of period	**4.2**	0.4	46.7
Cash and cash equivalents at end of period	**$23.1**	$4.2	$0.4
Supplemental cash flows information:			
Cash (paid) refunded during the period for:			
Interest	**($91.7)**	($91.5)	($93.1)
Income taxes, net	**($8.4)**	$27.8	($7.4)
Significant non-cash investing and financing activities:			
Accrued capital expenditures	**$114.5**	$93.1	$55.2
Transfer of investment in ATC and tax liability to ATI	**$—**	($163.6)	$—

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these statements.

WISCONSIN POWER AND LIGHT COMPANY
CONSOLIDATED STATEMENTS OF EQUITY

	Total WPL Common Equity				
	Common Stock	Additional Paid-In Capital	Retained Earnings	Noncontrolling Interest	Total Equity
			(in millions)		
2015:					
Beginning balance	$66.2	$959.0	$681.7	$8.5	$1,715.4
Net income			176.3	1.3	177.6
Common stock dividends			(126.9)		(126.9)
Contributions from noncontrolling interest				3.4	3.4
Distributions to noncontrolling interest				(1.9)	(1.9)
Ending balance	66.2	959.0	731.1	11.3	1,767.6
2016:					
Net income			190.4	2.4	192.8
Common stock dividends			(135.0)		(135.0)
Capital contribution from parent		60.0			60.0
Contributions from noncontrolling interest				11.5	11.5
Distributions to noncontrolling interest				(2.5)	(2.5)
Transfer of investment in ATC to ATI			(140.9)	(22.7)	(163.6)
Ending balance	66.2	1,019.0	645.6	—	1,730.8
2017:					
Net income			**186.6**		**186.6**
Common stock dividends			**(125.9)**		**(125.9)**
Capital contribution from parent		**90.0**			**90.0**
Ending balance	**$66.2**	**$1,109.0**	**$706.3**	**$—**	**$1,881.5**

The accompanying Combined Notes to Consolidated Financial Statements are an integral part of these statements.

ALLIANT ENERGY CORPORATION
INTERSTATE POWER AND LIGHT COMPANY
WISCONSIN POWER AND LIGHT COMPANY

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

NOTE 1(a) General -

Description of Business - Alliant Energy's financial statements include the accounts of Alliant Energy and its consolidated subsidiaries. Alliant Energy is a Midwest U.S. energy holding company, whose primary wholly-owned subsidiaries are IPL, WPL, AEF and Corporate Services.

IPL's financial statements include the accounts of IPL and its consolidated subsidiary, IPL SPE LLC, which is used for IPL's sales of accounts receivable program. IPL is a direct subsidiary of Alliant Energy and is a public utility engaged principally in the generation and distribution of electricity and the distribution and transportation of natural gas to retail customers in select markets in Iowa. IPL also sells electricity to wholesale customers in Minnesota, Illinois and Iowa, and is engaged in the generation and distribution of steam for two customers in Cedar Rapids, Iowa.

WPL's financial statements include the accounts of WPL and its consolidated subsidiary, WPL Transco, which held Alliant Energy's investment in ATC until December 31, 2016. Refer to Note 6(a) for discussion of WPL's transfer of its investment in ATC to ATI on December 31, 2016. WPL is a direct subsidiary of Alliant Energy and is a public utility engaged principally in the generation and distribution of electricity and the distribution and transportation of natural gas to retail customers in select markets in Wisconsin. WPL also sells electricity to wholesale customers in Wisconsin.

AEF is comprised of Transportation, ATI, a non-utility wind investment, the Sheboygan Falls Energy Facility and other non-utility investments. Transportation includes a short-line railway that provides freight service between Cedar Rapids, Iowa and Iowa City, Iowa; barge terminal and hauling services on the Mississippi River; and other transfer and storage services. ATI, a wholly-owned subsidiary of AEF, holds all of Alliant Energy's ATC Investment. The non-utility wind investment includes a 50% cash equity ownership interest in a 225 MW non-utility wind farm located in Oklahoma. The Sheboygan Falls Energy Facility is a 347 MW, simple-cycle, natural gas-fired EGU near Sheboygan Falls, Wisconsin, which is leased to WPL for an initial period of 20 years ending in 2025.

Corporate Services is the subsidiary formed to provide administrative services to Alliant Energy and its subsidiaries.

Basis of Presentation - The financial statements reflect investments in controlled subsidiaries on a consolidated basis and Alliant Energy's, IPL's and WPL's proportionate shares of jointly-owned utility EGUs. Unconsolidated investments, which Alliant Energy and WPL do not control, but have the ability to exercise significant influence over operating and financial policies, are accounted for under the equity method of accounting. Under the equity method of accounting, Alliant Energy and WPL initially record the investment at cost, and adjust the carrying amount of the investment to recognize their respective share of the earnings or losses of the investee. Dividends received from an investee reduce the carrying amount of the equity investment. Investments that do not meet the criteria for consolidation or the equity method of accounting are accounted for under the cost method. Refer to Notes 1(m) and 6(a) for further discussion of VIEs and equity method investments, respectively.

All intercompany balances and transactions, other than certain transactions affecting the rate-making process at IPL and WPL, have been eliminated from the financial statements. Such transactions not eliminated include costs that are recoverable from customers through rate-making processes. The financial statements are prepared in conformity with GAAP, which give recognition to the rate-making and accounting practices of FERC and state commissions having regulatory jurisdiction. Certain prior period amounts in the Financial Statements and Notes have been reclassified to conform to the current period presentation for comparative purposes, including reclassifications resulting from modifications to segment reporting as discussed in Note 17.

Discontinued operations reported in Alliant Energy's income statements is related to various warranty claims associated with the sale of RMT, Inc. in 2013, which have resulted in operating expenses and income subsequent to the sale. Alliant Energy presents cash flows from continuing operations together with cash flows from discontinued operations in its cash flows statements.

Use of Estimates - The preparation of the financial statements requires management to make estimates and assumptions that affect: (a) the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements; and (b) the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

NOTE 1(b) Regulatory Assets and Regulatory Liabilities - Alliant Energy, IPL and WPL are subject to regulation by FERC and various state regulatory commissions. As a result, Alliant Energy, IPL and WPL are subject to GAAP provisions for regulated operations, which provide that rate-regulated public utilities record certain costs and credits allowed in the rate-making process in different periods than for non-utility entities. Regulatory assets generally represent incurred costs that have been deferred as such costs are probable of recovery in future customer rates. Regulatory liabilities generally represent obligations to make refunds to customers or amounts collected in rates for which the related costs have not yet been incurred. Amounts recorded as regulatory assets or regulatory liabilities are generally recognized in the income statements at the time they are reflected in rates. Refer to Note 2 for additional discussion of regulatory assets and regulatory liabilities.

NOTE 1(c) Income Taxes - The liability method of accounting is followed for deferred taxes, which requires the establishment of deferred tax assets and liabilities, as appropriate, for temporary differences between the tax basis of assets and liabilities and the amounts reported in the financial statements. Deferred taxes are recorded using currently enacted tax rates, including impacts from Tax Reform and estimates of state apportionment. Changes in deferred tax assets and liabilities associated with certain property-related differences at IPL are accounted for differently than other subsidiaries of Alliant Energy due to rate-making practices in Iowa. Rate-making practices in Iowa do not include the impact of certain deferred tax expenses (benefits) in the determination of retail rates. Based on these rate-making practices, deferred tax expense (benefit) related to these property-related differences at IPL is not recorded in the income statement but instead recorded to regulatory assets or regulatory liabilities until these temporary differences reverse. Refer to Note 2 for further discussion of these tax-related regulatory assets and regulatory liabilities associated with property-related differences at IPL. In Wisconsin, the PSCW allows rate recovery of deferred tax expense on all temporary differences.

Investment tax credits are deferred and amortized to income over the average lives of the related property. Tax Reform repealed corporate federal AMT and allows unutilized AMT credits to be refunded over the next four tax years beginning with the U.S. federal tax return for calendar year 2018. Other tax credits reduce income tax expense in the year claimed.

Alliant Energy files a consolidated federal income tax return and a combined return in Wisconsin, which include Alliant Energy and its subsidiaries. Alliant Energy subsidiaries with a presence in Iowa file as part of a consolidated return in Iowa.

Alliant Energy allocates consolidated income tax expense to its subsidiaries that are members of the group that file a consolidated or combined income tax return. IPL and WPL use the modified separate return approach for calculating their income tax provisions and related deferred tax assets and liabilities. IPL and WPL are assumed to file separate tax returns with the federal and state taxing authorities, except that net operating losses (and other current or deferred tax attributes) are characterized as realized (or realizable) by IPL and WPL when those tax attributes are realized (or realizable) by the consolidated tax return group of Alliant Energy (even if IPL and WPL would not otherwise have realized the attributes on a stand-alone basis). The difference in the income taxes recorded for IPL and WPL under the modified separate return method compared to the income taxes recorded on a separate return basis was not material in 2017, 2016 and 2015.

Refer to Note 11 for further discussion of Tax Reform, which was enacted in December 2017.

NOTE 1(d) Cash and Cash Equivalents - Cash and cash equivalents include short-term liquid investments that have original maturities of less than 90 days.

NOTE 1(e) Property, Plant and Equipment -
Utility Plant -
General - Utility plant is recorded at the original cost of acquisition or construction, which includes material, labor, contractor services, AFUDC and allocable overheads, such as supervision, engineering, benefits, certain taxes and transportation. Repairs, replacements and renewals of items of property determined to be less than a unit of property or that do not increase the property's life or functionality are charged to maintenance expense. Generally, ordinary retirements of utility plant and salvage value are netted and charged to accumulated depreciation upon removal from utility plant accounts and no gain or loss is recognized consistent with rate-making principles. However, if regulators have approved recovery of the remaining net book value of property, plant and equipment that is retired early, or such approval by regulators is probable, the remaining net book value is reclassified from property, plant and equipment to regulatory assets upon retirement. Property, plant and equipment that is probable of being retired early is classified as plant anticipated to be retired early.

Depreciation - IPL and WPL use a combination of remaining life and straight-line depreciation methods as approved by their respective regulatory commissions. The composite or group method of depreciation is used, in which a single depreciation rate is applied to the gross investment in a particular class of property. This method pools similar assets and then depreciates each group as a whole. Periodic depreciation studies are performed to determine the appropriate group lives, net salvage, estimated cost of removal and group depreciation rates. These depreciation studies are subject to review and approval by IPL's and WPL's respective regulatory commissions. Depreciation expense is included within the recoverable cost of service component of rates charged to customers. The average rates of depreciation for electric, gas and other properties, consistent with current rate-making practices, were as follows:

	IPL			WPL		
	2017	2016	2015	**2017**	2016	2015
Electric - generation	**3.5%**	3.5%	3.6%	**3.5%**	3.1%	3.2%
Electric - distribution	**2.4%**	2.4%	2.4%	**2.6%**	2.6%	2.7%
Electric - other	**4.5%**	4.2%	4.0%	**6.9%**	4.7%	4.5%
Gas	**3.4%**	3.3%	3.2%	**2.5%**	2.5%	2.5%
Other	**4.0%**	3.9%	3.9%	**6.0%**	5.9%	6.0%

In September 2016, the PSCW issued an order approving the implementation of updated depreciation rates for WPL effective January 1, 2017 as a result of an updated depreciation study. In February 2018, the IUB issued an order approving the implementation of updated depreciation rates for IPL, which are currently expected to be effective in the first half of 2018, as a result of an updated depreciation study. IPL estimates the new average rates of depreciation for its electric generation and electric distribution properties will be approximately 3.8% and 2.8%, respectively, during 2018.

AFUDC - AFUDC represents costs to finance construction additions, including a return on equity component and cost of debt component as required by regulatory accounting. AFUDC for IPL's construction projects is calculated in accordance with FERC guidelines. AFUDC for WPL's retail and wholesale jurisdiction construction projects is calculated in accordance with PSCW and FERC guidelines, respectively. The AFUDC rates, computed in accordance with the prescribed regulatory formula, were as follows:

	2017	2016	2015
IPL (Marshalltown CWIP) (a)	**7.8%**	7.9%	7.9%
IPL (Wind generation CWIP) (b)	**7.6%**	N/A	N/A
IPL (other CWIP)	**7.6%**	7.7%	7.7%
WPL (retail jurisdiction)	**7.6%**	8.2%	8.2%
WPL (wholesale jurisdiction)	**6.0%**	6.7%	7.9%

(a) In 2013, the IUB issued an order establishing rate-making principles that require a 10.3% return on common equity for the calculation of AFUDC related to the construction of Marshalltown.

(b) In 2016, the IUB issued an order establishing rate-making principles that require a return on common equity for the calculation of AFUDC related to the construction of up to 500 MW of new wind generation equal to the greater of 10.0% or whatever percentage the IUB finds reasonable during IPL's most recent retail electric rate proceeding.

In accordance with their most recent rate orders, IPL applies its AFUDC rates to 100% of applicable CWIP balances and WPL generally applies its AFUDC rates to 50% of applicable CWIP balances. WPL may apply its AFUDC rates to 100% of the retail portion of the CWIP balances for construction projects requiring a CA or CPCN that were approved by the PSCW after its most recent rate order, including West Riverside.

Non-utility Property -

General - Non-utility property is recorded at the original cost of acquisition or construction, which includes material, labor and contractor services. Repairs, replacements and renewals of items of property determined to be less than a unit of property or that do not increase the property's life or functionality are charged to maintenance expense. Upon retirement or sale of non-utility property, the original cost and related accumulated depreciation are removed from the accounts and any gain or loss is included in the income statements.

Costs related to software developed or obtained for internal use are capitalized and amortized on a straight-line basis over the estimated useful life of the related software. If software is retired prior to being fully amortized, the difference is recorded as a loss in the income statements.

NOTE 1(f) Operating Revenues -

Utility - Revenues from Alliant Energy's utility business are primarily from electricity and natural gas sales and are recognized on an accrual basis as services are rendered or commodities are delivered to customers. Energy sales to individual customers are based on the reading of customers' meters, which occurs on a systematic basis throughout each reporting period. Amounts of energy delivered to customers since the date of the last meter reading are estimated at the end of each reporting period and the corresponding estimated unbilled revenue is recorded in such reporting period. The unbilled revenue estimate is based on daily system demand volumes, estimated customer usage by class, temperature impacts, line losses and the most recent customer rates.

IPL and WPL accrue revenues from their wholesale customers to the extent that the actual net revenue requirements calculated in accordance with FERC-approved formula rates for the reporting period are higher or lower than the amounts billed to wholesale customers during such period. Regulatory assets or regulatory liabilities are recorded as the offset for these accrued revenues under formulaic rate-making programs. IPL's estimated recovery amount is recorded in the current period of service and is reflected in customer bills within two years under the provisions of approved formula rates. WPL's estimated recovery amount is recorded in the current period of service and subject to final adjustments after a customer audit period in the subsequent year. Final settled recovery amounts are reflected in WPL's customer bills within two years under the provisions of approved formula rates.

IPL and WPL participate in bid/offer-based wholesale energy and ancillary services markets operated by MISO. MISO requires that all load serving entities and generation owners, including IPL and WPL, submit hourly bids and offers for energy and ancillary services. The MISO transactions are grouped together, resulting in a net supply to or net purchase from MISO for each hour of each day. The net supply to MISO is recorded in "Electric utility operating revenues" and the net purchase from MISO is recorded in "Electric production fuel and purchased power" in the income statements.

Non-utility - Revenues from Alliant Energy's non-utility businesses are primarily from its Transportation business and are recognized on an accrual basis as services are rendered or goods are delivered to customers.

Taxes Collected from Customers - Sales or various other taxes collected by certain of Alliant Energy's subsidiaries on behalf of other agencies are recorded on a net basis and are not included in operating revenues.

Revenue Recognition - Refer to Note 1(n) for discussion of a new accounting standard related to revenue recognition, which Alliant Energy, IPL and WPL adopted on January 1, 2018.

NOTE 1(g) Utility Cost Recovery Mechanisms -

Electric Production Fuel and Purchased Power (Fuel-related Costs) - Fuel-related costs are incurred to generate and purchase electricity to meet the demand of IPL's and WPL's electric customers. These fuel-related costs include the cost of fossil fuels (primarily natural gas and coal) used to produce electricity at their EGUs and electricity purchased from MISO wholesale energy markets and under PPAs. These fuel-related costs are recorded in "Electric production fuel and purchased power" in the income statements.

IPL Retail - The cost recovery mechanisms for IPL's retail electric customers provide for monthly adjustments to their electric rates for changes in fuel-related costs. Changes in the under-/over-collection of these costs are recognized in "Electric production fuel and purchased power" in Alliant Energy's and IPL's income statements. The cumulative effects of the under-/over-collection of these costs are recorded in regulatory assets or regulatory liabilities on Alliant Energy's and IPL's balance sheets until they are reflected in future billings to customers.

WPL Retail - The cost recovery mechanism for WPL's retail electric customers is based on forecasts of certain fuel-related costs expected to be incurred during forward-looking test year periods and fuel monitoring ranges determined by the PSCW during each retail electric rate proceeding or in a separate fuel cost plan approval proceeding. If WPL's actual fuel-related costs fall outside these fuel monitoring ranges, WPL is authorized to defer the incremental under-/over-collection of fuel-related costs that are outside the approved ranges. Deferral of under-collections are reduced to the extent actual return on common equity earned by WPL during the fuel cost plan year exceeds the most recently authorized return on common equity. Deferred amounts for fuel-related costs outside the approved fuel monitoring ranges are recognized in "Electric production fuel and purchased power" in Alliant Energy's and WPL's income statements. The cumulative effects of these deferred amounts are recorded in regulatory assets or regulatory liabilities on Alliant Energy's and WPL's balance sheets until they are reflected in future billings to customers.

IPL and WPL Wholesale - The cost recovery mechanisms for IPL's and WPL's wholesale electric customers provide for subsequent adjustments to their electric rates for changes in fuel-related costs. Changes in the under-/over-collection of these costs are recognized in "Electric production fuel and purchased power" in the income statements. The cumulative effects of the under-/over-collection of these costs are recorded in regulatory assets or regulatory liabilities on the balance sheets until they are reflected in future billings to customers.

Purchased Electric Capacity - PPAs help meet the electricity demand of IPL's and WPL's customers. Certain of these PPAs include minimum payments for IPL's and WPL's rights to electric generating capacity, which are charged each period to "Electric production fuel and purchased power" in the income statements. Purchased electric capacity expenses are recovered from IPL's and WPL's retail electric customers through changes in base rates determined during periodic rate proceedings. Purchased electric capacity expenses are recovered from IPL's and WPL's wholesale electric customers through annual changes in base rates determined by a formula rate structure.

Electric Transmission Service - Costs incurred for the transmission of electricity to meet the demands of IPL's and WPL's customers are charged to "Electric transmission service" in the income statements.

IPL Retail - Electric transmission service expense is recovered from IPL's retail electric customers through a transmission cost rider. This cost recovery mechanism provides for annual adjustments to electric rates charged to retail electric customers for changes in electric transmission service expense. Changes in the under-/over-collection of these costs are recognized in "Electric transmission service" in Alliant Energy's and IPL's income statements. The cumulative effects of the under-/over-collection of these costs are recorded in regulatory assets or regulatory liabilities on Alliant Energy's and IPL's balance sheets until they are reflected in future billings to customers.

WPL Retail - Electric transmission service expense is recovered from WPL's retail electric customers through changes in base rates determined during periodic rate proceedings. Pursuant to escrow accounting treatment approved by the PSCW, the difference between actual electric transmission service expense incurred and the amount of electric transmission service costs collected from customers as electric revenues is recognized in "Electric transmission service" in Alliant Energy's and WPL's income statements. An offsetting amount is recorded in regulatory assets or regulatory liabilities on Alliant Energy's and WPL's balance sheets until reflected in future billings to customers. The PSCW's December 2016 order for WPL's retail electric rate review (2017/2018 Test Period) extends this escrow accounting treatment through 2018.

IPL and WPL Wholesale - IPL and WPL arrange transmission service for the majority of their respective wholesale electric customers. Electric transmission service expense is allocated to and recovered from these customers based on a load ratio share computation.

Cost of Gas Sold - Costs are incurred for the purchase, transportation and storage of natural gas to serve IPL's and WPL's gas customers and the costs associated with the natural gas delivered to customers are charged to "Cost of gas sold" in the income statements. The tariffs for IPL's and WPL's retail gas customers provide for subsequent adjustments to their rates each month for changes in the cost of gas sold. Changes in the under-/over-collection of these costs are also recognized in "Cost of gas sold" in the income statements. The cumulative effects of the under-/over-collection of these costs are recorded in regulatory assets or regulatory liabilities on the balance sheets until they are reflected in future billings to customers.

Energy Efficiency Costs - Costs are incurred to fund energy efficiency programs and initiatives that help customers reduce their energy usage. The costs incurred for these programs and initiatives are charged to "Other operation and maintenance" in the income statements. Energy efficiency costs incurred by IPL are recovered from its retail electric and gas customers through an additional tariff called an energy efficiency cost recovery factor, which is revised annually and includes a reconciliation to eliminate any under-/over-collection of energy efficiency costs from prior periods. Energy efficiency costs incurred by WPL are recovered from retail electric and gas customers through changes in base rates determined during periodic rate proceedings. Reconciliations of any under-/over-collection of energy efficiency costs from prior periods are also addressed in WPL's periodic rate proceedings. Changes in the under-/over-collection of energy efficiency costs for IPL and WPL are recognized in "Other operation and maintenance" in the income statements. The cumulative effects of the under-/over-collection of these costs for IPL and WPL are recorded in regulatory assets or regulatory liabilities on the balance sheets until they are reflected in future billings to customers.

Refer to Note 2 for additional information regarding these utility cost recovery mechanisms.

NOTE 1(h) Financial Instruments - Financial instruments are periodically used for risk management purposes to mitigate exposures to fluctuations in certain commodity prices and transmission congestion costs. The fair value of those financial instruments that are determined to be derivatives are recorded as assets or liabilities on the balance sheets. Certain

commodity purchase and sales contracts qualify for and have been designated under the normal purchase and sale exception and are accounted for on the accrual basis of accounting. Alliant Energy, IPL and WPL have elected to not net the fair value amounts of derivatives subject to a master netting arrangement by counterparty. Alliant Energy, IPL and WPL do not offset fair value amounts recognized for the right to reclaim cash collateral (receivable) or the obligation to return cash collateral (payable) against fair value amounts recognized for derivative instruments that are executed with the same counterparty under the same master netting arrangement. Refer to Note 2 for discussion of the recognition of regulatory assets and regulatory liabilities related to the unrealized losses and gains on IPL's and WPL's derivative instruments. Refer to Notes 14, 15 and 16(f) for further discussion of derivatives and related credit risk.

NOTE 1(i) Asset Impairments -

Property, Plant and Equipment of Regulated Operations - Property, plant and equipment of regulated operations are reviewed for possible impairment whenever events or changes in circumstances indicate all or a portion of the carrying value of the assets may be disallowed for rate-making purposes. If IPL or WPL are disallowed recovery of any portion of the carrying value of their regulated property, plant and equipment that is under construction, has been recently completed or is probable of abandonment, or conclude it is probable recovery will be disallowed, an impairment charge is recognized equal to the amount of the carrying value that was disallowed or is probable of being disallowed. If IPL or WPL are only allowed a partial return on the carrying value of their regulated property, plant and equipment that is under construction, has been recently completed or is probable of abandonment, or conclude it is probable a full return will not be allowed, an impairment charge is recognized equal to the difference between the carrying value and the present value of the future revenues expected from their regulated property, plant and equipment.

Property, Plant and Equipment of Non-utility Operations - Property, plant and equipment of non-utility operations are reviewed for possible impairment whenever events or changes in circumstances indicate the carrying value of the assets may not be recoverable. Impairment is indicated if the carrying value of an asset exceeds its undiscounted future cash flows. If an impairment is indicated, a charge is recognized equal to the amount the carrying value exceeds the asset's fair value. Refer to Note 3 for discussion of Alliant Energy's impairment analysis of the Franklin County wind farm assets and resulting asset valuation charges recorded by Alliant Energy in 2016.

Unconsolidated Equity Investments - If events or circumstances indicate the carrying value of investments accounted for under the equity method of accounting exceeds fair value and the decline in value is other than temporary, potential impairment is assessed. If an impairment is indicated, a charge is recognized equal to the amount the carrying value exceeds the investment's fair value. Refer to Note 6(a) for additional discussion of investments accounted for under the equity method of accounting.

NOTE 1(j) Asset Retirement Obligations - The fair value of a legal obligation associated with the retirement of an asset is recorded as a liability when an asset is placed in service, when a legal obligation is subsequently identified or when sufficient information becomes available to determine a reasonable estimate of the fair value of future retirement costs. When an ARO is recorded as a liability, an equivalent amount is added to the asset cost. The fair value of AROs at inception is determined using discounted cash flows analyses. The liability is accreted to its present value and the capitalized cost is depreciated over the useful life of the related asset. Accretion and depreciation expenses related to AROs for IPL's and WPL's regulated operations are recorded to regulatory assets on the balance sheets. Upon regulatory approval to recover IPL's AROs expenditures, its regulatory assets are amortized to depreciation and amortization expenses in Alliant Energy's and IPL's income statements over the same time period the ARO expenditures are recovered from IPL's customers. WPL's regulatory assets related to AROs are being recovered as a component of depreciation rates pursuant to PSCW and FERC orders. Accretion and depreciation expenses related to AROs for Alliant Energy's non-utility operations are recorded to depreciation and amortization expenses in Alliant Energy's income statements. Upon settlement of the ARO liability, an entity settles the obligation for its recorded amount or incurs a gain or loss. Any gains or losses related to AROs for IPL's and WPL's regulated operations are recorded to regulatory liabilities or regulatory assets on the balance sheets. Refer to Note 13 for additional discussion of AROs.

NOTE 1(k) Debt Issuance and Retirement Costs - Debt issuance costs and debt premiums or discounts are presented on the balance sheet as a direct deduction from the carrying amount of the related debt liability, and are deferred and amortized over the expected life of each debt issue, considering maturity dates and, if applicable, redemption rights held by others. Alliant Energy's non-utility businesses and Corporate Services expense in the period of retirement any unamortized debt issuance costs and debt premiums or discounts on debt retired early.

NOTE 1(l) Allowance for Doubtful Accounts - Allowances for doubtful accounts are recorded for estimated losses resulting from the inability of customers to make required payments. Allowances for doubtful accounts are estimated based on historical write-offs, customer arrears and other economic factors within IPL's and WPL's service territories. Refer to Note 5(a) for details of allowance for doubtful accounts.

NOTE 1(m) Variable Interest Entities - An entity is considered a VIE if its equity investors do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties, or its equity investors lack any of the following characteristics: (1) power, through voting rights or similar rights, to direct the activities of the entity that most significantly impact the entity's economic performance; (2) the obligation to absorb expected losses of the entity; or (3) the right to receive expected benefits of the entity. The primary beneficiary of a VIE is required to consolidate the VIE. The financial statements do not reflect any consolidated VIEs.

NOTE 1(n) New Accounting Standards -

Revenue Recognition - In May 2014, the Financial Accounting Standards Board issued an accounting standard providing principles for recognizing revenue for the transfer of promised goods or services to customers with the consideration to which the entity expects to be entitled in exchange for those goods or services. This standard also requires disclosures about the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. Alliant Energy, IPL and WPL adopted this standard on January 1, 2018 and used the modified retrospective method of adoption and there will be no cumulative effect adjustments made to the opening retained earnings balance on January 1, 2018 upon adoption. The majority of Alliant Energy's, IPL's and WPL's revenues are from retail electric and gas sales from tariff offerings that provide electricity or natural gas without a defined contractual term. For such arrangements, revenues from contracts with customers will be equivalent to the electricity or natural gas supplied and billed, or estimated to be billed, and there will be no significant shift in the timing or pattern of revenue recognition for such sales. Alliant Energy, IPL and WPL did not have a material change in revenue recognition as a result of the adoption of this standard, and the most significant impact to their financial statements is in the form of additional disclosures. The incremental disclosures in future filings will include a separate footnote disclosure, including disaggregation of revenue by location and customer class.

Leases - In February 2016, the Financial Accounting Standards Board issued an accounting standard requiring lease assets and lease liabilities, including operating leases, to be recognized on the balance sheet for all leases with terms longer than 12 months. The standard also requires disclosure of key information about leasing arrangements. Alliant Energy, IPL and WPL currently expect to adopt this standard on January 1, 2019 and are evaluating the impact of this standard on their financial condition and results of operations and expect an increase in assets and liabilities from recognizing operating leases on their balance sheets.

Presentation of Net Periodic Pension and Postretirement Benefit Costs - In March 2017, the Financial Accounting Standards Board issued an accounting standard amending the income statement presentation of the components of net periodic benefit costs for defined benefit pension and other postretirement plans. The standard requires entities to (1) disaggregate the current service cost component from the other components of net periodic benefit costs and present it with other employee compensation costs in the income statement; and (2) include the other components in the income statement outside of operating income. This new presentation will shift the majority of the net periodic benefit costs from "Other operation and maintenance" expenses to "Interest expense and other" expenses in the income statements in future filings. In addition, only the service cost component of net periodic benefit costs is eligible for capitalization into property, plant and equipment, when applicable. IPL and WPL, as rate-regulated entities, will capitalize the other components of net periodic benefit costs into regulatory assets or regulatory liabilities. Alliant Energy, IPL and WPL adopted this standard on January 1, 2018 and used the retrospective method of adoption for the presentation requirements and the prospective method of adoption for the capitalization requirements.

Share-based Compensation Award Payments - In March 2016, the Financial Accounting Standards Board issued an accounting standard intended to simplify certain aspects of the accounting for share-based compensation award payments and the associated income taxes. This standard changes the accounting for excess tax benefits, whereby such benefits are recognized in the income statement instead of additional paid-in capital on the balance sheet. Alliant Energy adopted this standard on January 1, 2016, which resulted in a cumulative effect of a decrease to its deferred tax liabilities and an increase to its January 1, 2016 retained earnings balance of $3.1 million, which is included in "Other" in Alliant Energy's common equity statement in 2016.

NOTE 2. REGULATORY MATTERS

Regulatory Assets - At December 31, regulatory assets were comprised of the following items (in millions):

	Alliant Energy		IPL		WPL	
	2017	2016	**2017**	2016	**2017**	2016
Tax-related	**$778.2**	$1,055.6	**$750.5**	$1,022.4	**$27.7**	$33.2
Pension and OPEB costs	**548.0**	578.7	**274.4**	294.0	**273.6**	284.7
AROs	**109.3**	105.9	**72.5**	64.3	**36.8**	41.6
EGUs retired early	**63.8**	41.4	**31.6**	—	**32.2**	41.4
Derivatives	**45.3**	30.7	**21.8**	10.0	**23.5**	20.7
Emission allowances	**25.5**	26.2	**25.5**	26.2	**—**	—
Other	**96.6**	76.6	**55.3**	41.9	**41.3**	34.7
	$1,666.7	$1,915.1	**$1,231.6**	$1,458.8	**$435.1**	$456.3

A portion of the regulatory assets in the above table are not earning a return. These regulatory assets, but not the respective carrying costs of these regulatory assets, are expected to be recovered from customers in future rates. At December 31, 2017, IPL and WPL had $56 million and $5 million, respectively, of regulatory assets representing past expenditures that were not earning a return. IPL's regulatory assets that were not earning a return consisted primarily of emission allowances, debt redemption costs, and costs for clean air compliance and wind generation expansion projects. WPL's regulatory assets that were not earning a return consisted primarily of environmental-related costs, and amounts related to the wholesale portion of under-collected fuel-related costs, which is discussed in Note 1(g). The other regulatory assets reported in the above table either earn a return or the cash has not yet been expended, in which case the assets are offset by liabilities that also do not incur a carrying cost.

Tax-related - IPL and WPL record regulatory assets for certain temporary differences (primarily related to utility property, plant and equipment at IPL) that result in a decrease in current rates charged to customers and an increase in future rates charged to customers based on the timing of income tax expense that is used to determine such rates. These temporary differences for IPL include the impacts of qualifying deductions for repairs expenditures, allocation of mixed service costs, and Iowa accelerated tax depreciation, which all contribute to lower current income tax expense during the first part of an asset's useful life and higher current tax expense during the latter part of an asset's useful life. These regulatory assets will be recovered from customers in the future when these temporary differences reverse resulting in additional current income tax expense used to determine customers' rates. Tax-related regulatory assets are classified as non-current. During 2017, Alliant Energy's, IPL's and WPL's tax-related regulatory assets decreased primarily due to the impacts of Tax Reform, which is discussed in Note 11. As a result of the reduced tax rate from Tax Reform, the amount of taxes needed to be collected from customers in the future has decreased, which resulted in a corresponding decrease in the associated regulatory assets.

Pension and other postretirement benefits costs - The IUB and the PSCW have authorized IPL and WPL to record the retail portion of their respective previously unrecognized net actuarial gains and losses, and prior service costs and credits, as regulatory assets in lieu of AOCL on the balance sheets, as these amounts are expected to be recovered in future rates. IPL and WPL also recognize the wholesale portion of their previously unrecognized net actuarial gains and losses, and prior service costs and credits, as regulatory assets on the balance sheets because these amounts are expected to be recovered in rates in future periods under the formula rate structure. These regulatory assets will be increased or decreased as the net actuarial gains or losses, and prior service costs or credits, are subsequently amortized and recognized as a component of net periodic benefit costs. Regulatory assets are also increased or decreased as a result of the annual defined benefit plan measurement process.

Pension and OPEB costs are included within the recoverable cost of service component of rates charged to IPL's and WPL's customers. The recoverable costs included in customers' rates are based upon pension and OPEB costs determined in accordance with GAAP and are calculated using different methods for IPL's and WPL's respective regulatory jurisdictions. In February 2018, the IUB authorized IPL to recover from its Iowa retail electric customers an allocated portion of annual costs equal to a five-year inflation-adjusted average of actual costs incurred for 2013 through 2016 and an estimate of costs for its forward-looking post-Test Year (2017). The PSCW has authorized WPL to recover from its retail electric and gas customers an estimated allocated portion of annual costs equal to the costs expected to be incurred during each test period. IPL and WPL are authorized to recover from their wholesale customers an allocated portion of actual pension costs incurred each year through FERC-approved formula rates. Refer to Note 12(a) for additional details regarding pension and OPEB costs.

AROs - Alliant Energy, IPL and WPL believe it is probable that any differences between expenses accrued for legal AROs related to their utility operations and expenses recovered currently in rates will be recoverable in future rates, and are

deferring the differences as regulatory assets. IPL's settlement reached in September 2017 and approved by the IUB in February 2018 did not include the recovery of certain ARO costs previously recorded as regulatory assets, and as a result, Alliant Energy and IPL recorded a write-down of regulatory assets in 2017 as discussed in "IPL's Retail Electric Rate Review (2016 Test Year)" below. Refer to Note 13 for additional details of AROs.

Electric generating units retired early - In June 2017, IPL retired Sutherland Units 1 and 3 and reclassified the remaining net book value of these EGUs from property, plant and equipment to a regulatory asset on Alliant Energy's and IPL's balance sheets. IPL was earning a return on the remaining net book value of these EGUs, as well as recovering the remaining net book value of these EGUs from both its retail and wholesale customers. IPL's settlement reached in September 2017 and approved by the IUB in February 2018 authorized IPL to recover the remaining net book value of these EGUs from IPL's retail customers over a 10-year period; however, IPL is not allowed to earn a return on the remaining net book value of these EGUs from its retail customers. As a result, Alliant Energy and IPL recorded a write-down of regulatory assets in 2017 as discussed in "IPL's Retail Electric Rate Review (2016 Test Year)" below. In September 2017, FERC approved continued recovery of the remaining net book value of these EGUs from IPL's wholesale customers over a 10-year period.

In 2015, WPL retired Nelson Dewey Units 1 and 2 and Edgewater Unit 3. WPL received approval from the PSCW and FERC to reclassify the remaining net book value of these EGUs from property, plant and equipment to a regulatory asset on Alliant Energy's and WPL's balance sheets. The remaining net book value is included in WPL's rate base and WPL is earning a return on the outstanding balance. WPL is currently recovering the remaining net book value of these EGUs from both its retail and wholesale customers over a 10-year period beginning January 1, 2013 pursuant to PSCW and FERC orders.

Derivatives - In accordance with IPL's and WPL's fuel and natural gas recovery mechanisms, prudently incurred costs from derivative instruments are recoverable from customers in the future after any losses are realized, and gains from derivative instruments are refundable to customers in the future after any gains are realized. Based on these recovery mechanisms, the changes in the fair value of derivative liabilities/assets resulted in comparable changes to regulatory assets/liabilities on the balance sheets. Refer to Note 15 for additional details of derivative assets and derivative liabilities.

Emission allowances - IPL entered into forward contracts in 2007 to purchase SO2 emission allowances with vintage years of 2014 through 2017 from various counterparties to meet expected future emission reduction standards. Alliant Energy and IPL have recorded a regulatory asset for amounts paid under the forward contracts. In February 2018, the IUB authorized IPL to recover the unamortized forward contract costs for SO2 emission allowances through the energy adjustment clause over a 10-year period.

Other - Alliant Energy, IPL and WPL assess whether IPL's and WPL's regulatory assets are probable of future recovery by considering factors such as applicable regulations, recent orders by the applicable regulatory agencies, historical treatment of similar costs by the applicable regulatory agencies and regulatory environment changes. Based on these assessments, Alliant Energy, IPL and WPL believe the regulatory assets recognized as of December 31, 2017 in the above table are probable of future recovery. However, no assurance can be made that IPL and WPL will recover all of these regulatory assets in future rates. If future recovery of a regulatory asset ceases to be probable, the regulatory asset will be charged to expense in the period the likelihood of future recovery is less than probable.

Regulatory Liabilities - At December 31, regulatory liabilities were comprised of the following items (in millions):

	Alliant Energy		IPL		WPL	
	2017	2016	**2017**	2016	**2017**	2016
Tax-related	**$899.4**	$7.7	**$399.5**	$1.9	**$499.9**	$5.8
Cost of removal obligations	**410.0**	411.6	**274.5**	269.4	**135.5**	142.2
Electric transmission cost recovery	**90.4**	72.0	**26.4**	35.7	**64.0**	36.3
IPL's tax benefit riders	**25.0**	83.5	**25.0**	83.5	**—**	—
Commodity cost recovery	**21.0**	30.8	**14.6**	17.8	**6.4**	13.0
Energy efficiency cost recovery	**19.9**	20.5	**—**	—	**19.9**	20.5
Other	**31.5**	54.9	**15.4**	22.5	**16.1**	32.4
	$1,497.2	$681.0	**$755.4**	$430.8	**$741.8**	$250.2

Regulatory liabilities related to cost of removal obligations, to the extent expensed through depreciation rates, reduce rate base. Excluding the regulatory liabilities arising from Tax Reform, a significant portion of the remaining regulatory liabilities are not used to reduce rate base in the revenue requirement calculations utilized in IPL's and WPL's respective rate proceedings.

Tax-related - During 2017, Alliant Energy's, IPL's and WPL's tax-related regulatory liabilities increased primarily due to the impacts of Tax Reform, which is discussed in Note 11. Tax-related regulatory liabilities are classified as non-current.

Cost of removal obligations - Alliant Energy, IPL and WPL collect in rates future removal costs for many assets that do not have associated legal AROs. Alliant Energy, IPL and WPL record a regulatory liability for the estimated amounts they have collected in rates for these future removal costs and reduce the regulatory liability for amounts spent on removal activities.

Electric transmission cost recovery - A group of MISO cooperative and municipal utilities previously filed two complaints with FERC requesting a reduction to the base return on equity used by MISO transmission owners, including ITC and ATC, to determine electric transmission costs billed to utilities, including IPL and WPL. In 2016, FERC issued an order on the first complaint and established a base return on equity of 10.32%, excluding any incentive adders granted by FERC. The base return on equity of 10.32% was effective September 28, 2016, and was for the refund period from November 12, 2013 through February 11, 2015 (first complaint period). In 2017, Alliant Energy, IPL and WPL received the refunds for the first complaint period of $50 million, $39 million and $11 million, respectively, after final true-ups. IPL and WPL each initially recorded the retail portion of the refunds to a regulatory liability. Pursuant to IUB approval, IPL's retail portion of the refund from ITC was refunded to its retail customers in 2017. WPL's retail portion of the refund from ATC will remain in a regulatory liability until such refunds are approved to be returned to retail customers in a future rate proceeding. IPL's and WPL's wholesale customers received their share of the refunds through normal monthly billing practices in 2017. The second complaint covers the period from February 12, 2015 through May 11, 2016. A decision from FERC on the second complaint is currently expected in 2018. Refer to Note 1(g) for additional details of IPL's and WPL's electric transmission service cost recovery mechanisms.

IPL's tax benefit riders - The IUB has approved electric and gas tax benefit riders proposed by IPL, which utilize regulatory liabilities to credit bills of IPL's Iowa retail electric and gas customers to help offset the impact of rate increases on such customers. Alliant Energy and IPL recognize an offsetting reduction to income tax expense for the after-tax amounts credited to such customers, resulting in no impact to their net income from the electric and gas tax benefit riders. The tax benefit riders regulatory liabilities are related to tax benefits from tax accounting method changes for repairs expenditures and cost of removal expenditures, and a rate-making accounting change for capitalized interest. In 2017, Alliant Energy's and IPL's "IPL's tax benefit riders" regulatory liabilities increased (decreased) by ($59) million as follows (in millions):

Electric tax benefit rider credits	($65)
Gas tax benefit rider credits	(6)
Rate-making accounting change for capitalized interest	17
Tax Reform adjustment (Refer to Note 11)	(5)
	($59)

In 2017, Alliant Energy and IPL implemented a rate-making accounting change for capitalized interest. IPL currently anticipates crediting its related tax benefits from this rate-making accounting change to its Iowa retail electric and gas customers in the future, and as a result, Alliant Energy and IPL recorded an increase of $17 million to IPL's tax benefit riders regulatory liabilities in 2017.

The remaining electric tax benefit rider regulatory liabilities are currently expected to be credited to IPL's retail electric customers' bills over a 12-month period after final rates are effective, which is currently expected in the first half of 2018. The remaining gas tax benefit rider regulatory liabilities are currently expected to be credited to IPL's gas customers' bills by December 2018, subject to final review by the IUB.

Electric tax benefit rider - Details for IPL's electric tax benefit rider are as follows (in millions):

	2017	2016	2015
Credit to IPL's Iowa retail electric customers' bills with reduction to electric revenues (based on customers' KWh usage)	**$65**	$64	$72
Income tax benefit resulting from decreased taxable income caused by credits	**27**	27	30
Income tax benefit representing tax benefits realized from electric tax benefit rider	**38**	37	42

The IUB authorized IPL to reduce the electric tax benefit rider billing credits on customers' bills for 2013 through 2016 to recognize the revenue requirement impact of the changes in tax accounting methods related to tangible property and mixed service costs. The revenue requirement adjustment resulted in increases to electric revenues in Alliant Energy's and IPL's income statements and was recognized through the energy adjustment clause as a reduction of the credits on IPL's Iowa retail electric customers' bills from the electric tax benefit rider as follows (in millions):

	2016	2015
Revenue requirement adjustment	$14	$14

Gas tax benefit rider - Details for IPL's gas tax benefit rider are as follows (in millions):

	2017	2016	2015
Credit to IPL's Iowa retail gas customers' bills with reduction to gas revenues (based on a fixed amount per day)	**$6**	$12	$12
Income tax benefit resulting from decreased taxable income caused by credits	**3**	5	5
Income tax benefit representing tax benefits realized from gas tax benefit rider	**3**	7	7

Commodity cost recovery - Refer to Note 1(g) for additional details of IPL's and WPL's commodity cost recovery mechanisms.

Energy efficiency cost recovery - WPL and IPL collect revenues from their customers to offset certain expenditures they each incur for energy efficiency programs, including state mandated programs and Shared Savings programs. Differences between forecasted costs used to set rates and actual costs for these programs are deferred as a regulatory asset or regulatory liability.

Utility Rate Reviews -

IPL's Retail Electric Rate Review (2016 Test Year) - In April 2017, IPL filed a request with the IUB to increase annual electric base rates for its Iowa retail electric customers. The request was based on a 2016 historical Test Year as adjusted for certain known and measurable changes occurring up to 12 months after the commencement of the proceeding. The key drivers for the filing included recovery of capital projects, primarily power grid modernization and investments that advance cleaner energy, including Marshalltown. An interim retail electric base rate increase of $102 million, or approximately 7%, on an annual basis, was implemented effective April 13, 2017. Tax benefit rider credits and MISO transmission owner return on equity refunds were used to reduce the effect of the interim rate increase on customer bills in 2017. In 2017, Alliant Energy and IPL recorded increases in electric base rates of $77 million in conjunction with the interim retail electric base rate increase.

In September 2017, IPL reached a partial, non-unanimous settlement agreement with the Iowa Office of Consumer Advocate, the Iowa Business Energy Coalition and the Large Energy Group for an annual retail electric base rate increase of $130 million, or approximately 9%. In February 2018, the IUB issued an order approving the settlement. Final rates are currently expected to be effective in the first half of 2018 once all motions for reconsideration have been addressed and final tariffs have been approved by the IUB. The final rate increase includes continuation of the electric transmission cost rider; increased depreciation expense resulting from an updated depreciation study; recovery over a four-year period of ARO expenditures since the last retail electric rate filing in 2010; recovery over a 10-year period of the remaining net book value of Sutherland Units 1 and 3, unamortized forward contract costs for SO2 emission allowances through the energy adjustment clause and cancelled project costs approved in a prior EPB; and no double leverage applied to the weighted-average cost of capital. As a result of the partial settlement, in 2017, IPL recorded a write-down of regulatory assets of $9 million, including $4 million to "Other operation and maintenance" expenses primarily related to IPL being no longer probable of earning a return on the remaining net book value of Sutherland Units 1 and 3 from its retail customers when final rates are implemented, and $5 million to "Depreciation and amortization" expenses for certain AROs deemed no longer probable of recovery in future rates.

WPL's Retail Electric and Gas Rate Review (2017/2018 Test Period) - In December 2016, WPL received an order from the PSCW authorizing WPL to implement increases in annual retail electric and gas rates of $9 million and $9 million, respectively, effective January 1, 2017 followed by a freeze of such rates through the end of 2018. The $9 million net annual retail electric rate increase reflects a $60 million increase in base rates, partially offset by a $51 million reduction in fuel-related costs, using an estimate for 2017 fuel-related costs. The key drivers for the electric and gas base rate increases are recovery of the costs for environmental controls projects at Edgewater and Columbia, and investments in electric and gas distribution systems, including expansion of natural gas pipeline infrastructure. The filing also included utilization of amounts that WPL previously over-recovered from its customers for energy efficiency cost recovery and electric transmission

cost recovery, as well as amounts deferred under the earnings sharing mechanism for the 2013/2014 Test Period to reduce the requested base rate increases. The order included provisions that require WPL to defer a portion of its earnings if its annual regulatory return on common equity exceeds certain levels in 2017 or 2018. In 2017, Alliant Energy and WPL recorded increases in electric and gas base rates of $63 million and $9 million, respectively, in conjunction with the base rate increases authorized in the PSCW's December 2016 order.

WPL's Retail Electric and Gas Rate Review (2015/2016 Test Period) - In July 2014, WPL received an order from the PSCW authorizing WPL to maintain retail electric base rates at their then current levels through the end of 2016. The retail electric base rate review included a return of and return on costs for environmental controls projects, generation performance and reliability improvements, other ongoing capital expenditures and an increase in electric transmission service expense. The additional revenue requirement for these cost increases was offset by the impact of changes in the amortization of regulatory liabilities associated with energy efficiency recoveries and increased sales volumes. The order also authorized WPL to implement a $5 million decrease in annual base rates for its retail gas customers effective January 1, 2015 followed by a freeze of such gas base rates through the end of 2016. The order included provisions that required WPL to defer a portion of its earnings if its annual regulatory return on common equity exceeded certain levels in 2015 or 2016. As of December 31, 2017, Alliant Energy and WPL deferred $5 million of WPL's 2016 earnings for these provisions, which is included in "Other" in Alliant Energy's and WPL's regulatory liabilities tables above.

IPL's 2014 Retail Electric Rate Settlement Agreement - The IUB approved a settlement agreement in 2014 related to rates charged to IPL's Iowa retail electric customers. The settlement agreement extended IPL's Iowa retail electric base rates authorized in its 2009 Test Year rate review through 2016 and provided targeted retail electric customer billing credits of $105 million in aggregate. IPL recorded such billing credits as follows (in millions):

	2016	2015	2014
Billing credits to reduce retail electric customers' bills	$9	$24	$72

WPL's Retail Fuel-related Rate Filing (2016 Test Year) - Pursuant to a 2015 PSCW order, WPL's 2016 fuel-related costs were subject to deferral if they were outside an annual bandwidth of plus or minus 2% of the approved annual forecasted fuel-related costs. Retail fuel-related costs incurred by WPL in 2016 were lower than fuel-related costs used to determine rates for such period resulting in an over-collection of fuel-related costs. In August 2017, the PSCW authorized WPL to utilize $6 million of the over-collections as an offset to projected 2017 fuel-related cost under-collections. As of December 31, 2017, $3 million of remaining fuel-related costs for 2016 outside of the approved bandwidth are included in "Commodity cost recovery" in Alliant Energy's and WPL's regulatory liabilities table above, and these costs are expected to offset any rate changes for WPL's 2018 fuel-related costs.

WPL's Retail Fuel-related Rate Filing (2017 Test Year) - In March 2017, WPL filed an application with the PSCW for a mid-year fuel-related cost adjustment for 2017. Fuel-related costs for 2017 were expected to exceed the approved 2017 fuel-related cost plan by more than the 2% annual bandwidth. In August 2017, the PSCW authorized WPL to utilize $6 million of the 2016 fuel-related cost over-collections to offset a portion of the projected fuel-related cost under-collections for 2017. Retail fuel-related costs incurred by WPL in 2017 were higher than the projected fuel-related costs used to determine rates for such period resulting in an under-collection of fuel-related costs. As of December 31, 2017, after applying the 2016 over-recovery amounts, the remaining fuel-related costs for 2017 outside of the approved bandwidth were $5 million and are included in "Other" in Alliant Energy's and WPL's regulatory assets table above.

WPL's Retail Fuel-related Rate Filing (2018 Test Year) - In December 2017, WPL received an order from the PSCW authorizing an annual retail electric rate increase of $6 million, or approximately 1%, effective January 1, 2018. The increase primarily reflects a change in expected fuel-related costs in 2018, which was offset by $3 million of over-collections from WPL's 2016 fuel-related costs as discussed above.

NOTE 3. PROPERTY, PLANT AND EQUIPMENT

At December 31, details of property, plant and equipment on the balance sheets were as follows (in millions):

	Alliant Energy		IPL		WPL	
	2017	2016	**2017**	2016	**2017**	2016
Utility:						
Electric plant:						
Generation in service	**$6,655.3**	$5,866.9	**$3,715.9**	$2,916.8	**$2,939.4**	$2,950.1
Distribution in service	**5,123.5**	4,739.2	**2,820.9**	2,589.3	**2,302.6**	2,149.9
Other in service	**425.1**	329.1	**282.3**	223.5	**142.8**	105.6
Anticipated to be retired early (a)(b)	**93.0**	108.3	**—**	108.3	**93.0**	—
Total electric plant	**12,296.9**	11,043.5	**6,819.1**	5,837.9	**5,477.8**	5,205.6
Gas plant in service	**1,244.0**	1,107.6	**654.8**	556.7	**589.2**	550.9
Other plant in service	**571.9**	549.3	**333.4**	313.0	**238.5**	236.3
Accumulated depreciation	**(4,283.1)**	(4,135.7)	**(2,311.0)**	(2,258.3)	**(1,972.1)**	(1,877.4)
Net plant	**9,829.7**	8,564.7	**5,496.3**	4,449.3	**4,333.4**	4,115.4
Leased Sheboygan Falls Energy Facility, net (c)	**—**	—	**—**	—	**46.2**	52.4
Construction work in progress	**962.2**	1,226.8	**424.4**	968.1	**537.8**	258.7
Other, net	**6.0**	18.4	**5.5**	18.2	**0.5**	0.2
Total utility	**10,797.9**	9,809.9	**5,926.2**	5,435.6	**4,917.9**	4,426.7
Non-utility and other:						
Non-utility Generation, net (d)	**90.9**	135.0	**—**	—	**—**	—
Corporate Services and other, net (e)	**345.7**	334.3	—	—	—	—
Total non-utility and other	**436.6**	469.3	**—**	—	**—**	—
Total property, plant and equipment	**$11,234.5**	$10,279.2	**$5,926.2**	$5,435.6	**$4,917.9**	$4,426.7

(a) In 2017, IPL retired Sutherland Unit 3 and reclassified the remaining net book value of this EGU from property, plant and equipment to a regulatory asset on Alliant Energy's and IPL's balance sheets. Refer to Note 2 for further discussion, including recovery of the remaining net book value of Sutherland Unit 3.

(b) In 2017, WPL received approval from MISO to retire Edgewater Unit 4 and currently anticipates retiring this EGU by September 30, 2018. In 2016, the PSCW authorized WPL to recover the remaining net book value of Edgewater Unit 4 over a 10-year period beginning the later of the retirement date of the EGU or January 1, 2019.

(c) Less accumulated amortization of $77.6 million and $71.4 million for WPL as of December 31, 2017 and 2016, respectively. The Sheboygan Falls Energy Facility is eliminated from WPL upon consolidation and is included in the "Non-utility Generation, net" line within Alliant Energy's consolidated property, plant and equipment.

(d) Less accumulated depreciation of $50.5 million and $46.5 million for Alliant Energy as of December 31, 2017 and 2016, respectively. Refer to "Franklin County Wind Farm" below for discussion of the April 2017 transfer of the Franklin County wind farm from AEF to IPL pursuant to a February 2017 FERC order.

(e) Less accumulated depreciation of $285.6 million and $272.0 million for Alliant Energy as of December 31, 2017 and 2016, respectively.

Utility -

Natural Gas-Fired Generation Projects -

IPL's Marshalltown Generating Station - Construction of Marshalltown, a 706 MW natural gas-fired combined-cycle EGU, began in 2014 and was completed in 2017, which resulted in a transfer of the capitalized project costs from "Construction work in progress" to "Electric plant - Generation in service" in the above table for Alliant Energy and IPL in 2017. As of December 31, 2017 and 2016, the capitalized project costs for the EGU consisted of capitalized expenditures of $645 million and CWIP of $612 million, and AFUDC of $81 million and $68 million, respectively.

WPL's West Riverside Energy Center - WPL is currently constructing West Riverside, an approximate 730 MW natural gas-fired combined-cycle EGU. Construction began in 2016 and is currently expected to be completed by early 2020. As of December 31, 2017 and 2016, Alliant Energy and WPL recorded capitalized expenditures for CWIP of $339 million and $81 million, and AFUDC of $14 million and $2 million, respectively, for West Riverside in "Construction work in progress" in the above table for Alliant Energy and WPL. These capital expenditures do not yet reflect any potential impacts from the exercise of purchase options by certain WPL electric cooperatives for a partial ownership interest in West Riverside.

Wind Generation -
IPL's Expansion of Wind Generation - IPL currently plans to add up to 1,000 MW of new wind projects to its existing generation portfolio. These wind projects are expected to be placed into service in 2019 and 2020. As of December 31, 2017 and 2016, Alliant Energy and IPL recorded capitalized expenditures for CWIP of $264 million and $102 million, and AFUDC of $11 million and $1 million, respectively, for this expansion of wind generation in "Construction work in progress" in the above table for Alliant Energy and IPL.

Franklin County Wind Farm - In 2016, based on an evaluation of the strategic options for the Franklin County wind farm, Alliant Energy concluded it was probable the Franklin County wind farm would be transferred to IPL. As a result, Alliant Energy performed an impairment analysis of such assets and recorded non-cash, pre-tax asset valuation charges of $86 million (after-tax charges of $51 million, or $0.23 per share) in 2016. Alliant Energy recorded such charges as a reduction to property, plant and equipment on its balance sheet and charges to "Asset valuation charges for Franklin County wind farm" in its income statement in 2016.

In April 2017, the Franklin County wind farm was transferred from AEF to IPL as approved by a February 2017 FERC order. IPL's purchase price, including certain transaction-related costs, was $32 million. As of the closing date, the estimated fair values of the assets purchased and liabilities assumed by IPL were as follows (in millions):

Electric plant in service	$40
Current assets	2
Total assets acquired	42
Other liabilities	10
Net assets acquired	$32

WPL's Proposed Acquisition of Forward Wind Energy Center - In October 2017, WPL entered into definitive agreements to acquire the assets of FWEC, which is a 129 MW wind farm located in Wisconsin. WPL currently expects to acquire 55 MW of FWEC for approximately $74 million. In November 2017, WPL filed for approval from the PSCW to acquire the assets of FWEC, and a decision from the PSCW is currently expected in the first half of 2018. In January 2018, FERC approved WPL's request to acquire the assets of FWEC.

Sales of IPL's Minnesota Electric and Natural Gas Distribution Assets - In 2015, IPL completed the sale of its Minnesota natural gas distribution assets (primarily related to property, plant and equipment) and received proceeds of $11 million and a promissory note of $2 million. In 2015, IPL completed the sale of its Minnesota electric distribution assets (primarily related to property, plant and equipment) to Southern Minnesota Energy Cooperative, a combined group of various neighboring electric cooperatives, and received proceeds of $129 million. The proceeds from the natural gas distribution assets were used for general corporate purposes and the proceeds from the electric distribution assets were used to reduce cash amounts received from IPL's sales of accounts receivable program. The premium received over the book value of the property, plant and equipment sold was more than offset by a reduction in tax-related regulatory assets associated with the distribution assets. As a result, Alliant Energy and IPL recorded pre-tax charges of $11 million and $3 million for the Minnesota electric and natural gas distribution asset transactions, respectively, in "Other operation and maintenance" in their income statements in 2015.

The electric distribution asset sales agreement includes a wholesale power supply agreement between IPL and Southern Minnesota Energy Cooperative, which was approved by FERC in 2015 and became effective upon the sale of IPL's Minnesota electric distribution assets. The wholesale power supply agreement contains a five-year termination notice, which may not be given until the fifth anniversary of the effective date of the agreement, resulting in a minimum term of 10 years. The agreement remains in effect indefinitely, unless notice to terminate is provided by either party. This wholesale power supply agreement includes standardized pricing mechanisms that are detailed in IPL's current tariffs accepted by FERC through wholesale rate review proceedings. IPL's current return on common equity authorized by FERC related to its wholesale electric rates is 10.97%. As a result of IPL's requirement to supply electricity to Southern Minnesota Energy Cooperative under the wholesale power supply agreement, the sale of the electric distribution assets did not have a significant impact on IPL's generation plans or operating results.

AFUDC - AFUDC represents costs to finance construction additions, including a return on equity component and cost of debt component as required by regulatory accounting. The concurrent credit for the amount of AFUDC capitalized is recorded as "Allowance for funds used during construction" in the income statements. The amount of AFUDC generated by equity and debt components was as follows (in millions):

	Alliant Energy			IPL			WPL		
	2017	2016	2015	**2017**	2016	2015	**2017**	2016	2015
Equity	**$33.6**	$42.3	$24.4	**$21.1**	$35.2	$18.6	**$12.5**	$7.1	$5.8
Debt	**16.1**	20.2	12.5	**10.3**	16.8	9.6	**5.8**	3.4	2.9
	$49.7	$62.5	$36.9	**$31.4**	$52.0	$28.2	**$18.3**	$10.5	$8.7

Non-utility and Other - The non-utility and other property, plant and equipment recorded on Alliant Energy's balance sheets includes the following:

Non-utility Generation - The Sheboygan Falls Energy Facility was placed into service in 2005 and is depreciated using the straight-line method over a 35-year period. As of December 31, 2017, Alliant Energy recorded $91 million on its balance sheet related to the Sheboygan Falls Energy Facility.

Corporate Services and Other - Property, plant and equipment related to Corporate Services includes a customer billing and information system for IPL and WPL and other computer software, and the corporate headquarters building located in Madison, Wisconsin. The customer billing and information system is amortized using the straight-line method over a 12-year period. The majority of the remaining software is amortized over a 5-year period. Property, plant and equipment related to Transportation includes a short-line railway in Iowa and a barge terminal on the Mississippi River. The Corporate Services and Other property, plant and equipment is depreciated using the straight-line method over periods ranging from 5 to 30 years.

NOTE 4. JOINTLY-OWNED ELECTRIC UTILITY PLANT

Under joint ownership agreements with other utilities, IPL and WPL have undivided ownership interests in jointly-owned coal-fired EGUs. Each of the respective owners is responsible for the financing of its portion of the construction costs. KWh generation and operating expenses are primarily divided between the joint owners on the same basis as ownership. IPL's and WPL's shares of expenses from jointly-owned coal-fired EGUs are included in the corresponding operating expenses (e.g., electric production fuel, other operation and maintenance, etc.) in their income statements. Information relative to IPL's and WPL's ownership interest in these jointly-owned coal-fired EGUs at December 31, 2017 was as follows (dollars in millions):

	Ownership Interest %	Electric Plant	Accumulated Provision for Depreciation	Construction Work in Progress
IPL				
Ottumwa Unit 1	48.0%	$501.8	$144.9	$37.3
George Neal Unit 4	25.7%	187.2	85.2	0.8
George Neal Unit 3	28.0%	150.6	53.0	2.5
Louisa Unit 1	4.0%	37.8	22.4	1.4
		877.4	305.5	42.0
WPL				
Columbia Units 1-2	50.1%	714.7	216.8	46.9
Edgewater Unit 4	68.2%	99.9	60.4	0.1
		814.6	277.2	47.0
Alliant Energy		$1,692.0	$582.7	$89.0

In 2016, WPL received an order from the PSCW approving amendments to the Columbia joint operating agreement, which allow the co-owners to forgo certain capital expenditures at Columbia (excluding capital expenditures related to the Columbia Unit 2 SCR currently being constructed), resulting in WPL incurring these additional capital expenditures in exchange for a proportional increase in its ownership share of Columbia. Based on the additional capital expenditures WPL currently expects to incur through June 1, 2020, WPL's ownership interest in Columbia is expected to increase in the future. In June 2017, FERC approved these amendments to the Columbia joint operating agreement.

In October 2017, WPL received an order from the PSCW authorizing various electric cooperatives, which currently have wholesale power supply agreements with WPL, to acquire a partial ownership interest in West Riverside while the EGU is being constructed.

NOTE 5. RECEIVABLES

NOTE 5(a) Accounts Receivable - Details for accounts receivable included on the balance sheets as of December 31 were as follows (in millions):

	Alliant Energy		IPL		WPL	
	2017	2016	**2017**	2016	**2017**	2016
Customer	**$103.3**	$111.7	**$—**	$—	**$97.7**	$104.4
Unbilled utility revenues	**85.1**	90.2	**—**	—	**85.1**	90.2
Deferred proceeds	**222.1**	211.1	**222.1**	211.1	**—**	—
Other	**84.3**	89.0	**44.1**	30.7	**40.1**	38.8
Allowance for doubtful accounts	**(12.0)**	(8.7)	**(1.3)**	(1.1)	**(10.7)**	(7.1)
	$482.8	$493.3	**$264.9**	$240.7	**$212.2**	$226.3

NOTE 5(b) Sales of Accounts Receivable - IPL maintains a Receivables Agreement whereby it may sell its customer accounts receivables, unbilled revenues and certain other accounts receivables to a third party through wholly-owned and consolidated special purpose entities. The purchase commitment from the third party to which IPL sells its receivables expires in March 2018. IPL currently expects to amend and extend the purchase commitment. IPL pays a monthly fee to the third party that varies based on interest rates, limits on cash proceeds and cash amounts received from the third party. Deferred proceeds represent IPL's interest in the receivables sold to the third party. At IPL's request, deferred proceeds are paid to IPL from collections of receivables, after paying any required expenses incurred by the third party and the collection agent. Corporate Services acts as collection agent for the third party and receives a fee for collection services. The Receivables Agreement can be terminated by the third party if arrears or write-offs exceed certain levels. IPL was in compliance with all related covenants as of December 31, 2017.

Under the Receivables Agreement, IPL has the right to receive cash proceeds, up to a certain limit, from the third party in exchange for the receivables sold. Effective February 2017, the limit on cash proceeds was changed to $125 million. Cash proceeds are used by IPL to meet short-term financing needs, and cannot exceed the current limit or amount of receivables available for sale, whichever is less. As of December 31, 2017, IPL had $91.7 million of available capacity under its sales of accounts receivable program.

The transfers of receivables meet the criteria for sale accounting established by the transfer of financial assets accounting rules. IPL believes that the allowance for doubtful accounts related to its sales of receivables is a reasonable approximation of credit risk of the customers that generated the receivables. In 2017, 2016 and 2015, IPL's costs incurred related to the sales of accounts receivable program were not material. Refer to Note 14 for discussion of the fair value of deferred proceeds.

IPL's maximum and average outstanding aggregate cash proceeds (based on daily outstanding balances) related to the sales of accounts receivable program were as follows (in millions):

	Maximum			Average		
	2017	2016	2015	**2017**	2016	2015
Outstanding aggregate cash proceeds	**$112.0**	$172.0	$137.0	**$62.2**	$73.2	$46.7

As of December 31, the attributes of IPL's receivables sold under the Receivables Agreement were as follows (in millions):

	2017	2016
Customer accounts receivable	**$133.8**	$157.6
Unbilled utility revenues	**112.7**	90.4
Other receivables	**0.3**	0.1
Receivables sold to third party	**246.8**	248.1
Less: cash proceeds (a)	**12.0**	21.0
Deferred proceeds	**234.8**	227.1
Less: allowance for doubtful accounts	**12.7**	16.0
Fair value of deferred proceeds	**$222.1**	$211.1
Outstanding receivables past due	**$44.7**	$68.0

(a) Changes in cash proceeds are presented in "Sales of accounts receivable" in operating activities in Alliant Energy's and IPL's cash flows statements.

Additional attributes of IPL's receivables sold under the Receivables Agreement were as follows (in millions):

	2017	2016	2015
Collections reinvested in receivables	**$1,647.1**	$1,818.1	$1,812.9
Write-offs, net of recoveries	**17.7**	4.8	8.8

In connection with the implementation of IPL's new customer billing and information system in 2016, IPL postponed the write-off of customer bills for a portion of 2016, resulting in lower write-offs in 2016, higher write-offs in 2017 and higher outstanding receivables past due as of December 31, 2016.

NOTE 6. INVESTMENTS

NOTE 6(a) Unconsolidated Equity Investments - Unconsolidated investments accounted for under the equity method of accounting are as follows (in millions):

	Ownership Interest at December 31, 2017	Carrying Value at December 31,		Equity (Income) / Loss		
		2017	2016	**2017**	2016	2015
Alliant Energy						
ATC Investment (a)	16%-20%	**$274.2**	$317.6	**($42.4)**	($39.1)	($34.2)
Wind Investment in Oklahoma	50%	**98.3**	—	**(1.8)**	—	—
Other	Various	**8.9**	8.4	**(0.6)**	(0.5)	0.4
		$381.4	$326.0	**($44.8)**	($39.6)	($33.8)
WPL						
ATC	—%	**$—**	$—	**$—**	($39.1)	($34.2)
Wisconsin River Power Company	50%	**8.3**	7.7	**(0.7)**	(0.7)	(0.9)
		$8.3	$7.7	**($0.7)**	($39.8)	($35.1)

(a) As of December 31, 2017, Alliant Energy's ATC Investment is comprised of a 16% ownership interest in ATC and a 20% ownership interest in ATC Holdco LLC, which are described below. In 2017, Alliant Energy's investment in ATC decreased due to the impacts of Tax Reform. Refer to Note 11 for further discussion. Alliant Energy currently has the ability to exercise significant influence over ATC's financial and operating policies through its participation on ATC's Board of Directors. Refer to Note 18 for information regarding related party transactions with ATC.

Summary aggregate financial information from the financial statements of these investments is as follows (in millions):

	Alliant Energy			WPL		
	2017	2016	2015	**2017**	2016	2015
Operating revenues	**$741**	$658	$624	**$8**	$658	$624
Operating income	**374**	331	299	**4**	331	299
Net income	**267**	232	186	**2**	234	202
As of December 31:						
Current assets	**104**	82		**7**	6	
Non-current assets	**5,041**	4,340		**20**	19	
Current liabilities	**770**	498		**2**	3	
Non-current liabilities	**2,038**	2,144		**8**	7	
Minority interest	**255**	—		**—**	—	

Investment in ATC and WPL's Noncontrolling Interest - Prior to 2014, WPL owned 100% of WPL Transco, which held Alliant Energy's investment in ATC. In 2014, WPL Transco's operating agreement was amended to allow ATI, a wholly-owned subsidiary of AEF, to become a member of WPL Transco in addition to WPL. In 2014, ATI began funding capital contributions that WPL Transco made to ATC. WPL Transco's equity income from ATC and ATC dividends received by WPL Transco were allocated between WPL and ATI based on their respective ownership interests at the time the equity income was generated and at the time of the dividend payments. Prior to the transfer of the investment in ATC to ATI discussed below, WPL consolidated WPL Transco, and ATI's ownership in WPL Transco was recorded as a noncontrolling interest in total equity on WPL's balance sheets.

On December 31, 2016, pursuant to a June 2016 PSCW order, WPL Transco was liquidated and WPL transferred its investment in ATC to ATI. As a result, WPL no longer records equity income from its prior investment in ATC. In conjunction with the transfer of the investment in ATC, a deferred intercompany tax gain recognized by WPL was assumed by ATI. The impact of WPL's transfer of the ATC investment, including the assumption of such intercompany tax gain by

ATI, was recorded as a net reduction in total equity of $163.6 million on WPL's balance sheet. WPL's income statement includes all of the equity earnings from ATC through December 31, 2016, the date of transfer. There were no impacts of this transfer to Alliant Energy's consolidated financial statements. As of December 31, 2016, ATI owns Alliant Energy's entire ATC Investment.

Investment in ATC Holdco LLC - In 2011, Duke Energy Corporation and ATC announced the creation of DATC, a joint venture that is expected to acquire, build, own and operate new electric transmission infrastructure in North America. DATC continues to evaluate new projects and opportunities, and participates in a competitive bidding process on projects it considers to be viable. In October 2017, ATC transferred a portion of its interest in DATC to ATC Holdco LLC, and as a result, Alliant Energy contributed additional equity capital funding based on its ownership interest in ATC Holdco LLC. A portion of proceeds from the transfer was distributed to all ATC Holdco LLC's owners based on their ATC ownership percentage.

Non-utility Wind Investment in Oklahoma - In July 2017, a wholly-owned subsidiary of AEF acquired 50% of a cash equity ownership interest in a 225 MW non-utility wind farm located in Oklahoma, which started commercial operations in December 2016. This wind farm has both cash and tax equity ownership. The wind farm provides electricity to a third-party under a long-term PPA. In 2017, Alliant Energy's "Other investments" assets increased $98 million from this acquisition. Alliant Energy will not maintain or operate the wind farm, and provided a parent guarantee of its subsidiary's indemnification obligations under the operating agreement and PPA. Refer to Note 16(d) for discussion of the guarantee. Alliant Energy accounts for this non-utility investment under the equity method of accounting. In conjunction with the acquisition, in July 2017, AEF entered into a $95 million, 364-day variable-rate term loan credit agreement (with Alliant Energy as guarantor).

NOTE 6(b) Cash Surrender Value of Life Insurance Policies - Various life insurance policies cover certain current and former employees and directors. In 2016, certain of Alliant Energy's and IPL's company-owned life insurance policies were liquidated. The related proceeds of $31 million and $19 million were recorded in investing activities in Alliant Energy's and IPL's cash flows statements, respectively, in 2016. At December 31, the cash surrender value of these investments was as follows (in millions):

	Alliant Energy		WPL	
	2017	2016	**2017**	2016
Cash surrender value	**$10.4**	$10.6	**$5.6**	$5.8

NOTE 7. COMMON EQUITY

Common Share Activity - A summary of Alliant Energy's common stock activity was as follows:

	2017	2016	2015
Shares outstanding, January 1	**227,673,654**	226,918,432	221,871,360
At-the-market offering programs	**3,074,931**	—	4,373,234
Shareowner Direct Plan issuances	**640,723**	732,814	606,010
Equity-based compensation plans (Note 12(b))	**5,185**	22,408	112,756
Other	**(45,847)**	—	(44,928)
Shares outstanding, December 31	**231,348,646**	227,673,654	226,918,432

At December 31, 2017, Alliant Energy had a total of 12.4 million shares available for issuance in the aggregate, pursuant to its Amended and Restated OIP, Shareowner Direct Plan and 401(k) Savings Plan.

At-the-Market Offering Programs - In 2017 and 2015, Alliant Energy filed prospectus supplements under which it could sell up to $125 million and $150 million of its common stock, respectively, through at-the-market offering programs. In 2017, Alliant Energy issued 3,074,931 shares of common stock through this program and received cash proceeds of $124 million, net of $1 million in commissions and fees. In 2015, Alliant Energy issued 4,373,234 shares of common stock through this program and received cash proceeds of $133 million, net of $2 million in commissions and fees. The proceeds from the issuances of common stock were used for general corporate purposes. The 2015 at-the-market offering program expired in 2016, and Alliant Energy currently has no plans to issue any additional common stock through the 2017 at-the-market offering program.

Shareowner Direct Plan - Alliant Energy satisfies its requirements under the Shareowner Direct Plan (dividend reinvestment and stock purchase plan) by acquiring Alliant Energy common stock through original issue, rather than on the open market.

Shareowner Rights Agreement - Alliant Energy previously established an amended and restated Shareowner Rights Agreement. The rights under this agreement were exercisable if a person or group acquired, or announced an intention to acquire, 15% or more of Alliant Energy's outstanding common stock. In January 2018, Alliant Energy's Board of Directors authorized the redemption of the rights, which were redeemed to shareowners as of the close of business on January 31, 2018.

Dividend Restrictions - Alliant Energy does not have any significant common stock dividend restrictions. IPL and WPL each have common stock dividend restrictions based on applicable regulatory limitations. IPL also has common stock dividend restrictions based on the terms of its outstanding preferred stock. As of December 31, 2017, IPL and WPL were in compliance with all such dividend restrictions.

IPL is restricted from paying common stock dividends to its parent company, Alliant Energy, if for any past or current dividend period, dividends on its preferred stock have not been paid, or declared and set apart for payment. IPL has paid all dividends on its preferred stock through 2017. Under the Federal Power Act, IPL may not pay dividends to its parent company in excess of the current amount of its retained earnings. As of December 31, 2017, IPL's amount of retained earnings that were free of dividend restrictions was $679 million. If IPL's actual 13-month average common equity ratio (calculated on a financial basis consistent with IPL's rate reviews) falls below 42% of total capitalization, IPL is required to notify the IUB.

Pursuant to a December 2016 PSCW order, WPL has a regulatory limitation on distributions to its parent company. WPL is prohibited from paying annual common stock dividends to its parent company in excess of forecasted dividend levels of $140 million in 2018 if WPL's actual 13-month average common equity ratio (calculated on a financial basis consistent with WPL's rate reviews) would fall below 51.00% for 2018. As of December 31, 2017, WPL's amount of retained earnings that were free of dividend restrictions was $140 million for 2018.

Restricted Net Assets of Subsidiaries - IPL and WPL do not have regulatory authority to lend or advance any amounts to their parent company. As of December 31, 2017, the amount of IPL's and WPL's net assets that were not available to be transferred to their parent company, Alliant Energy, in the form of loans, advances or cash dividends without the consent of IPL's and WPL's regulatory authorities was $1.8 billion and $1.7 billion, respectively.

Comprehensive Income - In 2017, 2016 and 2015, Alliant Energy's other comprehensive income (loss) was ($0.1) million, $0 million and $0.2 million, respectively; therefore, its comprehensive income was substantially equal to its net income and its comprehensive income attributable to Alliant Energy common shareowners was substantially equal to its net income attributable to Alliant Energy common shareowners for such periods. In 2017, 2016 and 2015, IPL and WPL had no other comprehensive income; therefore their comprehensive income was equal to their net income and their comprehensive income available for common stock was equal to their earnings available for common stock for such periods.

NOTE 8. REDEEMABLE PREFERRED STOCK

IPL is authorized to issue up to 16,000,000 shares of cumulative preferred stock in aggregate. Information related to the carrying value of IPL's cumulative preferred stock at December 31 was as follows:

Series	Liquidation Preference/Stated Value	Shares Authorized	Shares Outstanding	**2017**	2016
				(in millions)	
5.1%	$25	8,000,000	8,000,000	**$200.0**	$200.0

On or after March 15, 2018, IPL may, at its option, redeem the 5.1% cumulative preferred stock for cash at a redemption price of $25 per share plus accrued and unpaid dividends up to the redemption date.

The current articles of incorporation of IPL contain a provision that grants the holders of its cumulative preferred stock voting rights to elect two members of IPL's Board of Directors if preferred dividends equal to six or more quarterly dividend requirements (whether or not consecutive) are in arrears. Such voting rights would not provide the holders of IPL's preferred stock control of the decision on redemption of IPL's preferred stock and could not force IPL to exercise its call option. Therefore, IPL's cumulative preferred stock is presented in total equity on Alliant Energy's and IPL's balance sheets in a manner consistent with noncontrolling interests.

Refer to Note 14 for information on the fair value of cumulative preferred stock.

NOTE 9. DEBT

NOTE 9(a) Short-term Debt - Alliant Energy and its subsidiaries maintain committed bank lines of credit to provide short-term borrowing flexibility and back-stop liquidity for commercial paper outstanding. In August 2017, Alliant Energy, IPL and WPL entered into a single new credit facility agreement, which expires in August 2022. At December 31, 2017, the short-term borrowing capacity under the credit facility agreement totaled $1 billion ($400 million for Alliant Energy at the parent company level, $250 million for IPL and $350 million for WPL). Subject to certain conditions, Alliant Energy (at the parent company level), IPL and WPL may each reallocate and change its sublimit up to $500 million, $400 million and $500 million, respectively, within the $1 billion total commitment. Information regarding commercial paper classified as short-term debt and back-stopped by the credit facility was as follows (dollars in millions):

	Alliant Energy		IPL		WPL	
December 31	**2017**	2016	**2017**	2016	**2017**	2016
Commercial paper outstanding	**$320.2**	$244.1	**$—**	$—	**$25.0**	$52.3
Commercial paper weighted average interest rates	**2.0%**	0.9%	**N/A**	N/A	**1.5%**	0.7%
Available credit facility capacity	**$679.8**	$755.9	**$250.0**	$300.0	**$325.0**	$347.7

	Alliant Energy		IPL		WPL	
For the year ended	**2017**	2016	**2017**	2016	**2017**	2016
Maximum amount outstanding (based on daily outstanding balances)	**$424.4**	$251.8	**$20.0**	$3.1	**$271.2**	$118.3
Average amount outstanding (based on daily outstanding balances)	**$294.3**	$179.0	**$0.5**	$—	**$118.2**	$38.1
Weighted average interest rates	**1.2%**	0.6%	**1.3%**	0.7%	**1.0%**	0.4%

In July 2017, AEF entered into a $95 million, 364-day variable-rate (2.2% at December 31, 2017) term loan credit agreement (with Alliant Energy as guarantor) related to the acquisition of a cash equity ownership interest in a non-utility wind farm located in Oklahoma, which includes substantially the same financial covenants that are included in the credit facility agreement. Refer to Note 6(a) for further discussion of the non-utility wind farm investment.

Financial Covenants - The single new credit facility agreement contains a financial covenant, which requires Alliant Energy, IPL and WPL to maintain certain debt-to-capital ratios in order to borrow under the credit facility. AEF's term loan credit agreement contains a financial covenant, which requires Alliant Energy to maintain a certain debt-to-capital ratio in order to borrow under the term loan credit agreement. The required debt-to-capital ratios compared to the actual debt-to-capital ratios at December 31, 2017 were as follows:

	Alliant Energy	IPL	WPL
Requirement, not to exceed	65%	65%	65%
Actual	54%	47%	51%

The debt component of the capital ratios includes long- and short-term debt (excluding non-recourse debt and hybrid securities to the extent the total carrying value of such hybrid securities does not exceed 15% of consolidated capital of the applicable borrower), capital lease obligations, certain letters of credit, guarantees of the foregoing and new synthetic leases. Unfunded vested benefits under qualified pension plans and sales of accounts receivable are not included in the debt-to-capital ratios. The equity component of the capital ratios excludes accumulated other comprehensive income (loss).

NOTE 9(b) Long-Term Debt - Long-term debt, net as of December 31 was as follows (dollars in millions):

	2017			2016		
	Alliant Energy	**IPL**	**WPL**	Alliant Energy	IPL	WPL
Senior Debentures (a):						
5.875%, due 2018	**$100.0**	**$100.0**	**$—**	$100.0	$100.0	$—
7.25%, due 2018	**250.0**	**250.0**	**—**	250.0	250.0	—
3.65%, due 2020	**200.0**	**200.0**	**—**	200.0	200.0	—
3.25%, due 2024 (b)	**500.0**	**500.0**	**—**	250.0	250.0	—
3.4%, due 2025	**250.0**	**250.0**	**—**	250.0	250.0	—
5.5%, due 2025	**50.0**	**50.0**	**—**	50.0	50.0	—
6.45%, due 2033	**100.0**	**100.0**	**—**	100.0	100.0	—
6.3%, due 2034	**125.0**	**125.0**	**—**	125.0	125.0	—
6.25%, due 2039	**300.0**	**300.0**	**—**	300.0	300.0	—
4.7%, due 2043	**250.0**	**250.0**	**—**	250.0	250.0	—
3.7%, due 2046	**300.0**	**300.0**	**—**	300.0	300.0	—
	2,425.0	**2,425.0**	**—**	2,175.0	2,175.0	—
Debentures (a):						
5%, due 2019	**250.0**	**—**	**250.0**	250.0	—	250.0
4.6%, due 2020	**150.0**	**—**	**150.0**	150.0	—	150.0
2.25%, due 2022	**250.0**	**—**	**250.0**	250.0	—	250.0
3.05%, due 2027 (c)	**300.0**	**—**	**300.0**	—	—	—
6.25%, due 2034	**100.0**	**—**	**100.0**	100.0	—	100.0
6.375%, due 2037	**300.0**	**—**	**300.0**	300.0	—	300.0
7.6%, due 2038	**250.0**	**—**	**250.0**	250.0	—	250.0
4.1%, due 2044	**250.0**	**—**	**250.0**	250.0	—	250.0
	1,850.0	**—**	**1,850.0**	1,550.0	—	1,550.0
Other:						
AEF term loan credit agreement through 2018, 2% at December 31, 2017 (with Alliant Energy as guarantor) (d)	**500.0**	**—**	**—**	500.0	—	—
Corporate Services 3.45% senior notes, due 2022 (a)	**75.0**	**—**	**—**	75.0	—	—
Sheboygan Power, LLC 5.06% senior secured notes, due 2018 to 2024 (secured by the Sheboygan Falls Energy Facility and related assets) (a)	**49.6**	**—**	**—**	53.8	—	—
Other, 1% at December 31, 2017, due 2018 to 2025	**2.9**	**—**	**—**	3.3	—	—
	627.5	**—**	**—**	632.1	—	—
Subtotal	**4,902.5**	**2,425.0**	**1,850.0**	4,357.1	2,175.0	1,550.0
Current maturities	**(855.7)**	**(350.0)**	**—**	(4.6)	—	—
Unamortized debt issuance costs	**(25.4)**	**(14.3)**	**(10.5)**	(23.4)	(13.7)	(9.1)
Unamortized debt (discount) and premium, net	**(10.8)**	**(4.7)**	**(6.1)**	(13.5)	(7.8)	(5.7)
Long-term debt, net (e)	**$4,010.6**	**$2,056.0**	**$1,833.4**	$4,315.6	$2,153.5	$1,535.2

(a) Contains optional redemption provisions which, if elected by the issuer at its sole discretion, could require material redemption premium payments by the issuer. The redemption premium payments under these optional redemption provisions are variable and dependent on applicable U.S. Treasury rates at the time of redemption.
(b) In 2017, IPL issued $250 million of 3.25% senior debentures due 2024. The proceeds from the issuance were used by IPL to reduce commercial paper classified as long-term debt, reduce cash amounts received from its sales of accounts receivable program and for general corporate purposes.
(c) In 2017, WPL issued $300 million of 3.05% debentures due 2027. The proceeds from the issuance were used by WPL to reduce commercial paper and for general corporate purposes.
(d) Refer to Note 9(a) for discussion of a financial covenant contained in AEF's term loan credit agreement.
(e) There were no significant sinking fund requirements related to the outstanding long-term debt.

Five-Year Schedule of Long-term Debt Maturities - At December 31, 2017, long-term debt maturities for 2018 through 2022 were as follows (in millions):

	2018	2019	2020	2021	2022
IPL	$350	$—	$200	$—	$—
WPL	—	250	150	—	250
Corporate Services	—	—	—	—	75
AEF	506	6	7	8	8
Alliant Energy	$856	$256	$357	$8	$333

Fair Value of Long-term Debt - Refer to Note 14 for information on the fair value of long-term debt outstanding.

NOTE 10. LEASES

NOTE 10(a) Operating Leases - Various agreements have been entered into related to property, plant and equipment rights that are accounted for as operating leases. In 2017, 2016 and 2015, rental expenses associated with operating leases were not material. At December 31, 2017, future minimum operating lease payments, excluding contingent rentals, were as follows (in millions):

	2018	2019	2020	2021	2022	Thereafter	Total
Alliant Energy	$6	$5	$2	$2	$1	$13	$29
IPL	3	2	1	1	1	13	21
WPL	3	3	1	—	—	—	7

NOTE 10(b) Capital Leases -

WPL - In 2005, WPL entered into a 20-year agreement with AEF's Non-utility Generation business to lease the Sheboygan Falls Energy Facility, with an option for two lease renewal periods thereafter. The lease became effective in 2005 when the EGU began commercial operation. WPL is responsible for the operation of the EGU and has exclusive rights to its output, and the PSCW approved this affiliated lease agreement in 2005. The capital lease asset is amortized using the straight-line method over the 20-year lease term. WPL's retail and wholesale rates include recovery of the Sheboygan Falls Energy Facility lease payments. The Sheboygan Falls Energy Facility lease expenses were included in WPL's income statements as follows (in millions):

	2017	2016	2015
Interest expense	**$8.7**	$9.3	$9.9
Depreciation and amortization	**6.2**	6.2	6.2
	$14.9	$15.5	$16.1

At December 31, 2017, WPL's estimated future minimum capital lease payments for the Sheboygan Falls Energy Facility were as follows (in millions):

	2018	2019	2020	2021	2022	Thereafter	Total	Less: amount representing interest	Present value of minimum capital lease payments
Sheboygan Falls Energy Facility	$15	$15	$15	$15	$15	$35	$110	$33	$77

NOTE 11. INCOME TAXES

Tax Reform - In December 2017, Tax Reform was enacted. Substantially all of the provisions of Tax Reform are effective for taxable years beginning after December 31, 2017. The most significant provisions of Tax Reform that impact Alliant Energy, IPL and WPL were the reduction in the federal corporate tax rate from 35% to 21%, the repeal of the federal corporate alternative minimum tax (AMT), and the elimination of bonus depreciation deductions on utility property placed in service after September 27, 2017 unless a binding contract existed as of that date.

The enactment of Tax Reform in December 2017 had a material impact on Alliant Energy's, IPL's and WPL's 2017 financial statements as the tax effects of the changes in tax laws must be recognized in the period in which the law is enacted. Alliant Energy, IPL and WPL have completed their assessment of the applicable provisions of Tax Reform, and the impacts to their 2017 balance sheets and income statements are as follows (in millions):

	Alliant Energy	IPL	WPL
Balance Sheet			
Other current assets	$—	$4.7	($1.4)
Investments:			
ATC Investment	(75.0)	—	—
Other assets:			
Regulatory assets	(387.6)	(375.0)	(12.7)
Deferred charges and other	41.0	—	—
Total Tax Reform impact on assets	($421.6)	($370.3)	($14.1)
Other liabilities:			
Deferred tax liabilities	($1,331.9)	($757.2)	($523.8)
Regulatory liabilities	885.9	390.7	495.2
Other	6.3	—	—
Total Tax Reform impact on liabilities	($439.7)	($366.5)	($28.6)
Income Statement			
Income tax expense (benefit)	($18.1)	$3.8	($14.5)

Deferred Tax Liabilities - Deferred tax assets and liabilities are measured at the enacted tax rate expected to be applied when temporary differences are to be realized or settled. Given the enactment of Tax Reform in December 2017, Alliant Energy's, IPL's and WPL's deferred tax assets and liabilities at December 31, 2017 were re-measured based upon the new corporate tax rate. Alliant Energy's utility operations in IPL and WPL recorded the net changes from re-measuring deferred tax assets and liabilities as a change in regulatory liabilities or regulatory assets as described in further detail below. Alliant Energy's, IPL's and WPL's non-utility operations recorded the net change in deferred tax assets and liabilities to "Income tax expense (benefit)" in their respective income statement or as an increase to "Other liabilities" or decrease in "ATC Investment" on Alliant Energy's balance sheet.

Regulatory Assets and Regulatory Liabilities - Tax Reform requires regulated utilities to account for certain changes in deferred taxes related to accelerated depreciation and net operating losses using a normalization method of accounting. This method of accounting requires regulated utilities to record the normalized changes in deferred tax liabilities and assets to a regulatory liability or regulatory asset. For other changes to regulatory assets and regulatory liabilities resulting from Tax Reform, IPL and WPL are awaiting decisions from the IUB, PCSW and FERC to determine the appropriate regulatory treatment. IPL and WPL have recorded the offset to the changes in utility deferred tax liabilities and assets in a regulatory liability or regulatory asset to be reflected in future customer billings. Future changes may occur based on decisions received from the IUB, PSCW and FERC.

In January 2018, the IUB issued an order initiating investigation of the impacts of Tax Reform. The order requires IPL to track all calculated differences since January 1, 2018 resulting from Tax Reform, such that any over-collections can be refunded to its customers at a future date, if appropriate. In January 2018, the PSCW issued an order directing WPL to defer and to accrue carrying costs on the revenue requirement impacts resulting from Tax Reform since its inception.

ATC Investment - Tax Reform required a re-measurement of deferred tax assets and liabilities associated with Alliant Energy's ATC Investment. These deferred tax assets and liabilities have been utilized to determine the amount of costs billed by ATC to its customers. Due to the regulated nature of ATC and FERC policy on income tax allowances, Alliant Energy expects the changes in deferred taxes that have been collected in ATC's customers' rates to be returned to such customers over the regulatory life of ATC's assets. As a result, Alliant Energy has reduced the deferred tax liabilities associated with the ATC Investment and recorded the offset to "ATC Investment" on its balance sheet. Starting in 2018, the adjustment as a result of the change in deferred taxes will be amortized as a reduction in deferred tax expense over the remaining life of ATC's assets.

Deferred Charges and Other - Tax Reform repealed corporate federal AMT and allows unutilized AMT credits to be refunded over the next four tax years beginning with the U.S. federal tax return for calendar year 2018. As a result of these changes, Alliant Energy reclassified $41 million of unutilized AMT credits from a deferred tax asset into a long-term tax receivable in 2017 in anticipation of future refunds of such tax credits. The long-term tax receivable is included in "Deferred charges and other" on Alliant Energy's balance sheet.

Income Tax Expense (Benefit) -The changes in deferred taxes for Alliant Energy's, IPL's and WPL's non-utility operations were primarily recorded in the income statements. In addition, Alliant Energy recognized valuation allowances for certain tax credit carryforwards as a result of Tax Reform that are discussed in more detail below.

Income Tax Expense (Benefit) - The components of "Income tax expense (benefit)" in the income statements were as follows (in millions):

	Alliant Energy			IPL			WPL		
	2017	2016	2015	**2017**	2016	2015	**2017**	2016	2015
Current tax expense (benefit):									
Federal	**($41.0)**	$1.8	$2.0	**($27.9)**	($12.8)	($14.1)	**$5.5**	($22.3)	$4.7
State	**8.5**	17.2	3.2	**1.6**	15.5	11.5	**2.5**	1.1	0.6
IPL's tax benefit riders	**(40.4)**	(44.2)	(49.0)	**(40.4)**	(44.2)	(49.0)	**—**	—	—
Deferred tax expense (benefit):									
Federal	**159.5**	112.8	120.8	**72.5**	59.1	40.7	**55.0**	112.3	76.8
State	**12.3**	4.9	27.9	**(2.2)**	(9.0)	3.3	**16.6**	20.8	20.2
Production tax credits	**(31.1)**	(31.8)	(33.1)	**(14.1)**	(14.0)	(14.5)	**(17.0)**	(17.8)	(18.6)
Investment tax credits	**(1.1)**	(1.3)	(1.4)	**(0.4)**	(0.5)	(0.6)	**(0.7)**	(0.8)	(0.8)
	$66.7	$59.4	$70.4	**($10.9)**	($5.9)	($22.7)	**$61.9**	$93.3	$82.9

Income Tax Rates - The overall income tax rates shown in the following table were computed by dividing income tax expense (benefit) by income from continuing operations before income taxes.

	Alliant Energy			IPL			WPL		
	2017	2016	2015	**2017**	2016	2015	**2017**	2016	2015
Statutory federal income tax rate	**35.0%**	35.0%	35.0%	**35.0%**	35.0%	35.0%	**35.0%**	35.0%	35.0%
State income taxes, net of federal benefits	**5.5**	5.4	5.2	**6.5**	6.4	6.2	**5.1**	5.1	5.1
Effect of rate-making on property-related differences	**(8.5)**	(8.5)	(6.8)	**(19.1)**	(16.2)	(17.2)	**(1.7)**	(0.7)	(0.5)
IPL's tax benefit riders	**(7.6)**	(10.0)	(10.6)	**(18.7)**	(20.1)	(28.3)	**—**	—	—
Production tax credits	**(6.1)**	(7.2)	(7.2)	**(6.7)**	(6.3)	(8.3)	**(7.1)**	(6.2)	(7.1)
Impact of Tax Reform	**(3.4)**	—	—	**1.7**	—	—	**(5.8)**	—	—
Other items, net	**(2.4)**	(1.3)	(0.3)	**(3.7)**	(1.5)	(0.5)	**(0.6)**	(0.6)	(0.7)
Overall income tax rate	**12.5%**	13.4%	15.3%	**(5.0%)**	(2.7%)	(13.1%)	**24.9%**	32.6%	31.8%

Deferred Tax Assets and Liabilities - The deferred tax assets and liabilities included on the balance sheets at December 31 arise from the following temporary differences (in millions):

	Alliant Energy		IPL		WPL	
	2017	2016	**2017**	2016	**2017**	2016
Deferred tax liabilities:						
Property	**$1,852.7**	$2,919.0	**$1,102.6**	$1,677.0	**$674.2**	$1,124.5
ATC Investment	**86.4**	153.1	**—**	—	**—**	—
Other	**75.9**	95.1	**63.4**	71.4	**36.5**	58.8
Total deferred tax liabilities	**2,015.0**	3,167.2	**1,166.0**	1,748.4	**710.7**	1,183.3
Deferred tax assets:						
Federal credit carryforwards	**260.7**	268.4	**113.1**	95.9	**131.0**	112.9
Net operating losses carryforwards - federal	**174.4**	173.3	**107.4**	69.6	**43.7**	75.4
Regulatory liability - IPL's tax benefit riders	**7.4**	34.7	**7.4**	34.7	**—**	—
Net operating losses carryforwards - state	**41.3**	32.9	**0.9**	0.6	**0.2**	0.1
Other	**61.8**	87.9	**27.1**	35.8	**14.7**	23.6
Subtotal deferred tax assets	**545.6**	597.2	**255.9**	236.6	**189.6**	212.0
Valuation allowance	**(9.0)**	(0.2)	**(0.6)**	—	**(1.3)**	(0.3)
Total deferred tax assets	**536.6**	597.0	**255.3**	236.6	**188.3**	211.7
Total deferred tax liabilities, net	**$1,478.4**	$2,570.2	**$910.7**	$1,511.8	**$522.4**	$971.6

The decreases in deferred tax liabilities were primarily due to the reduction in the federal corporate tax rate from 35% to 21% as a result of Tax Reform, as discussed above.

Property - The decrease in property-related deferred tax liabilities from Tax Reform was partially offset by bonus depreciation deductions from property placed in service in 2017, including IPL's Marshalltown Generating Station. Alliant Energy currently estimates its total bonus depreciation deductions to be claimed on its U.S. federal income tax return for calendar year 2017 will be approximately $670 million ($500 million for IPL and $140 million for WPL).

Carryforwards - The decrease in Alliant Energy's federal credit carryforwards was due to the reclassification of AMT credits to a long-term tax receivable as a result of Tax Reform, partially offset by production tax credits generated in 2017. The increase in Alliant Energy's and IPL's federal net operating losses carryforwards was primarily due to bonus depreciation deductions for property placed in service in 2017, including IPL's Marshalltown Generating Station, largely offset by the impacts of Tax Reform.

At December 31, 2017, carryforwards and expiration dates were estimated as follows (in millions):

	Range of Expiration Dates	Alliant Energy	IPL	WPL
Federal net operating losses	2030-2037	$852	$537	$208
State net operating losses	2018-2037	700	13	2
Federal tax credits	2022-2037	267	119	131

Valuation Allowances - Due to the anticipated future reductions in revenues from utility customers due to Tax Reform, Alliant Energy expects a reduction in its future consolidated taxable income, which will extend the period to which prior unutilized operating losses will be utilized. Taxable income must be reduced by net operating losses carryforwards prior to utilizing federal tax credit carryforwards. Alliant Energy expects to utilize its net operating losses carryforwards by 2024 and therefore, currently does not expect to utilize 2002 and 2003 vintage federal credit carryforwards prior to their expiration in 2022 and 2023, respectively. This has resulted in valuation allowance charges recorded to "Income tax expense (benefit)" on the income statements as noted in the table above.

Uncertain Tax Positions - At December 31, 2017, 2016 and 2015, there were no uncertain tax positions or penalties accrued related to uncertain tax positions, and interest accrued and tax positions favorably impacting future effective tax rates for continuing operations were not material. As of December 31, 2017, no material changes to unrecognized tax benefits are expected during the next 12 months.

Open tax years - Tax years that remain subject to the statute of limitations in the major jurisdictions for each of Alliant Energy, IPL and WPL are as follows:

Consolidated federal income tax returns (a)	2014 - 2016
Consolidated Iowa income tax returns (b)	2014 - 2016
Wisconsin combined tax returns (c)	2013 - 2016

(a) These federal tax returns are effectively settled as a result of participation in the IRS Compliance Assurance Program, which allows Alliant Energy and the IRS to work together to resolve issues related to Alliant Energy's current tax year before filing its federal income tax return. The statute of limitations for these federal tax returns expires three years from each filing date.
(b) The statute of limitations for these Iowa tax returns expires three years from each filing date.
(c) The statute of limitations for these Wisconsin combined tax returns expires four years from each filing date.

NOTE 12. BENEFIT PLANS

NOTE 12(a) Pension and Other Postretirement Benefits Plans - Retirement benefits are provided to substantially all employees through various qualified and non-qualified non-contributory defined benefit pension plans (currently closed to new hires), and/or through defined contribution plans (including 401(k) savings plans). Benefits of the non-contributory defined benefit pension plans are based on the plan participant's years of service, age and compensation. Benefits of the defined contribution plans are based on the plan participant's years of service, age, compensation and contributions. Certain defined benefit postretirement health care and life benefits are provided to eligible retirees. In general, the retiree health care plans consist of fixed benefit subsidy structures and the retiree life insurance plans are non-contributory.

IPL and WPL account for their participation in Alliant Energy and Corporate Services sponsored plans as multiple-employer plans. In IPL's and WPL's tables below, the defined benefit pension plan amounts represent those respective amounts for their bargaining unit employees covered under the qualified plans that they sponsor, as well as amounts directly assigned to them related to their current and former non-bargaining employees who are participants in the Alliant Energy and Corporate Services sponsored qualified and non-qualified defined benefit pension plans. In IPL's and WPL's tables below, the OPEB plan amounts represent respective amounts for their employees, as well as amounts directly assigned to them related to their current and former non-bargaining employees who are participants in the Corporate Services sponsored OPEB plan.

Assumptions - The assumptions for defined benefit pension and OPEB plans at the measurement date of December 31 were as follows:

	Defined Benefit Pension Plans			OPEB Plans		
Alliant Energy	**2017**	2016	2015	**2017**	2016	2015
Discount rate for benefit obligations	**3.66%**	4.19%	4.47%	**3.53%**	3.98%	4.30%
Discount rate for net periodic cost	**4.19%**	4.47%	4.18%	**3.98%**	4.30%	3.97%
Expected rate of return on plan assets	**7.60%**	7.60%	7.60%	**5.80%**	6.30%	6.20%
Rate of compensation increase	**3.65% - 4.50%**	3.65% - 4.50%	3.65% - 4.50%	**N/A**	N/A	N/A
Medical cost trend on covered charges:						
Initial trend rate (end of year)	**N/A**	N/A	N/A	**6.75%**	7.00%	7.25%
Ultimate trend rate	**N/A**	N/A	N/A	**5.00%**	5.00%	5.00%

	Qualified Defined Benefit Pension Plan			OPEB Plans		
IPL	**2017**	2016	2015	**2017**	2016	2015
Discount rate for benefit obligations	**3.68%**	4.22%	4.50%	**3.51%**	3.95%	4.28%
Discount rate for net periodic cost	**4.22%**	4.50%	4.20%	**3.95%**	4.28%	3.94%
Expected rate of return on plan assets	**7.60%**	7.60%	7.60%	**6.20%**	6.60%	6.60%
Rate of compensation increase	**3.65%**	3.65%	3.65%	**N/A**	N/A	N/A
Medical cost trend on covered charges:						
Initial trend rate (end of year)	**N/A**	N/A	N/A	**6.75%**	7.00%	7.25%
Ultimate trend rate	**N/A**	N/A	N/A	**5.00%**	5.00%	5.00%

	Qualified Defined Benefit Pension Plan			OPEB Plans		
WPL	**2017**	2016	2015	**2017**	2016	2015
Discount rate for benefit obligations	**3.69%**	4.23%	4.51%	**3.51%**	3.96%	4.28%
Discount rate for net periodic cost	**4.23%**	4.51%	4.20%	**3.96%**	4.28%	3.96%
Expected rate of return on plan assets	**7.60%**	7.60%	7.60%	**3.50%**	4.70%	4.60%
Rate of compensation increase	**3.65%**	3.65%	3.65%	**N/A**	N/A	N/A
Medical cost trend on covered charges:						
Initial trend rate (end of year)	**N/A**	N/A	N/A	**6.75%**	7.00%	7.25%
Ultimate trend rate	**N/A**	N/A	N/A	**5.00%**	5.00%	5.00%

Expected rate of return on plan assets - The expected rate of return on plan assets is based on projected asset class returns using target allocations. A forward-looking building blocks approach is used, and historical returns, survey information and capital market information are analyzed to support the expected rate of return on plan assets assumption. Refer to “Investment Strategy for Plan Assets” below for additional information related to investment strategy and mix of assets for the pension and OPEB plans.

Life Expectancy - The life expectancy assumption is used in determining the benefit obligation and net periodic benefit cost for defined benefit pension and OPEB plans. This assumption was updated to utilize mortality tables that were released in 2014 by the Society of Actuaries and updated in 2015 and 2016.

Net Periodic Benefit Costs (Credits) - The components of net periodic benefit costs (credits) for sponsored defined benefit pension and OPEB plans are included in the tables below (in millions). Net periodic benefit costs are primarily included in “Other operation and maintenance” in the income statements.

	Defined Benefit Pension Plans			OPEB Plans		
Alliant Energy	**2017**	2016	2015	**2017**	2016	2015
Service cost	**$12.5**	$12.6	$15.9	**$5.0**	$5.3	$5.5
Interest cost	**51.0**	53.0	53.6	**8.6**	9.4	9.1
Expected return on plan assets (a)	**(65.5)**	(65.5)	(75.0)	**(6.1)**	(6.1)	(8.4)
Amortization of prior service credit (b)	**(0.4)**	(0.3)	(0.2)	**(0.2)**	(4.1)	(11.3)
Amortization of actuarial loss (c)	**37.6**	37.4	35.4	**3.8**	4.7	4.8
Additional benefit costs	**—**	—	0.5	**—**	—	—
Settlement losses (d)	**0.9**	—	—	**—**	—	—
	$36.1	$37.2	$30.2	**$11.1**	$9.2	($0.3)

	Defined Benefit Pension Plans			OPEB Plans		
IPL	**2017**	2016	2015	**2017**	2016	2015
Service cost	**$7.3**	$7.5	$8.8	**$2.1**	$2.3	$2.4
Interest cost	**23.5**	24.5	25.0	**3.5**	3.8	3.8
Expected return on plan assets (a)	**(30.8)**	(30.9)	(35.8)	**(4.3)**	(4.3)	(5.7)
Amortization of prior service credit (b)	**(0.2)**	(0.2)	(0.1)	**—**	(2.6)	(6.1)
Amortization of actuarial loss (c)	**16.1**	16.5	15.3	**2.0**	2.6	2.3
	$15.9	$17.4	$13.2	**$3.3**	$1.8	($3.3)

	Defined Benefit Pension Plans			OPEB Plans		
WPL	**2017**	2016	2015	**2017**	2016	2015
Service cost	**$4.9**	$4.9	$5.8	**$1.9**	$2.0	$2.1
Interest cost	**21.8**	22.3	22.6	**3.4**	3.8	3.7
Expected return on plan assets (a)	**(28.5)**	(28.3)	(32.4)	**(0.8)**	(0.8)	(1.5)
Amortization of prior service cost (credit) (b)	**0.1**	0.2	0.2	**(0.2)**	(0.9)	(3.5)
Amortization of actuarial loss (c)	**18.5**	17.6	16.8	**1.6**	1.8	2.2
Additional benefit costs	**—**	—	0.5	**—**	—	—
	$16.8	$16.7	$13.5	**$5.9**	$5.9	$3.0

(a) The expected return on plan assets is based on the expected rate of return on plan assets and the fair value approach to the market-related value of plan assets.
(b) Unrecognized prior service costs (credits) for the OPEB plans are amortized over the average future service period to full eligibility of the participants of each plan.
(c) Unrecognized net actuarial gains or losses in excess of 10% of the greater of the plans' benefit obligations or assets are amortized over the average future service lives of plan participants, except for the Alliant Energy Cash Balance Pension Plan where gains or losses outside the 10% threshold are amortized over the time period the participants are expected to receive benefits.
(d) Settlement losses related to payments made to retired executives of Alliant Energy.

The estimated amortization from "Regulatory assets" and "Regulatory liabilities" on the balance sheets and AOCL on Alliant Energy's balance sheet into net periodic benefit cost in 2018 is as follows (in millions):

	Alliant Energy		IPL		WPL	
	Defined Benefit Pension Plans	OPEB Plans	Defined Benefit Pension Plans	OPEB Plans	Defined Benefit Pension Plans	OPEB Plans
Actuarial loss	$35.2	$3.4	$15.0	$1.2	$17.2	$2.0
Prior service credit	(0.7)	(0.2)	(0.2)	—	(0.2)	(0.2)
	$34.5	$3.2	$14.8	$1.2	$17.0	$1.8

Benefit Plan Assets and Obligations - A reconciliation of the funded status of qualified and non-qualified defined benefit pension and OPEB plans to the amounts recognized on the balance sheets at December 31 was as follows (in millions):

	Defined Benefit Pension Plans		OPEB Plans	
Alliant Energy	**2017**	2016	**2017**	2016
Change in benefit obligation:				
Net benefit obligation at January 1	**$1,244.3**	$1,206.3	**$220.1**	$221.4
Service cost	**12.5**	12.6	**5.0**	5.3
Interest cost	**51.0**	53.0	**8.6**	9.4
Plan participants' contributions	**—**	—	**2.9**	2.4
Actuarial (gain) loss	**83.6**	48.3	**5.4**	(0.3)
Gross benefits paid	**(88.3)**	(75.9)	**(19.7)**	(18.1)
Net benefit obligation at December 31	**1,303.1**	1,244.3	**222.3**	220.1
Change in plan assets:				
Fair value of plan assets at January 1	**895.7**	895.0	**105.8**	106.9
Actual return on plan assets	**136.7**	74.3	**12.9**	8.2
Employer contributions	**6.6**	2.3	**9.2**	6.4
Plan participants' contributions	**—**	—	**2.9**	2.4
Gross benefits paid	**(88.3)**	(75.9)	**(19.7)**	(18.1)
Fair value of plan assets at December 31	**950.7**	895.7	**111.1**	105.8
Under funded status at December 31	**($352.4)**	($348.6)	**($111.2)**	($114.3)

	Defined Benefit Pension Plans		OPEB Plans	
Alliant Energy	**2017**	2016	**2017**	2016
Amounts recognized on the balance sheets consist of:				
Non-current assets	**$—**	$—	**$8.8**	$3.2
Current liabilities	**(2.2)**	(6.5)	**(9.1)**	(8.6)
Pension and other benefit obligations	**(350.2)**	(342.1)	**(110.9)**	(108.9)
Net amounts recognized at December 31	**($352.4)**	($348.6)	**($111.2)**	($114.3)
Amounts recognized in Regulatory Assets (refer to Note 2 for details) and AOCL (refer to Alliant Energy's common equity statements for details) consist of:				
Net actuarial loss	**$509.1**	$535.1	**$47.4**	$52.6
Prior service credit	**(6.5)**	(6.9)	**(1.3)**	(1.5)
	$502.6	$528.2	**$46.1**	$51.1

	Defined Benefit Pension Plans		OPEB Plans	
IPL	**2017**	2016	**2017**	2016
Change in benefit obligation:				
Net benefit obligation at January 1	**$570.4**	$556.1	**$90.1**	$91.3
Service cost	**7.3**	7.5	**2.1**	2.3
Interest cost	**23.5**	24.5	**3.5**	3.8
Plan participants' contributions	**—**	—	**1.0**	0.9
Actuarial (gain) loss	**34.9**	19.1	**(0.1)**	(0.7)
Gross benefits paid	**(43.2)**	(36.8)	**(7.2)**	(7.5)
Net benefit obligation at December 31	**592.9**	570.4	**89.4**	90.1
Change in plan assets:				
Fair value of plan assets at January 1	**422.0**	422.7	**68.2**	69.2
Actual return on plan assets	**64.3**	35.3	**8.9**	5.3
Employer contributions	**0.6**	0.8	**2.0**	0.3
Plan participants' contributions	**—**	—	**1.0**	0.9
Gross benefits paid	**(43.2)**	(36.8)	**(7.2)**	(7.5)
Fair value of plan assets at December 31	**443.7**	422.0	**72.9**	68.2
Under funded status at December 31	**($149.2)**	($148.4)	**($16.5)**	($21.9)

IPL	Defined Benefit Pension Plans 2017	Defined Benefit Pension Plans 2016	OPEB Plans 2017	OPEB Plans 2016
Amounts recognized on the balance sheets consist of:				
Non-current assets	**$—**	$—	**$5.9**	$0.4
Current liabilities	**(0.5)**	(0.7)	**(2.0)**	(1.9)
Pension and other benefit obligations	**(148.7)**	(147.7)	**(20.4)**	(20.4)
Net amounts recognized at December 31	**($149.2)**	($148.4)	**($16.5)**	($21.9)
Amounts recognized in Regulatory Assets consist of (refer to Note 2 for details):				
Net actuarial loss	**$218.9**	$233.6	**$18.7**	$25.4
Prior service credit	**(2.1)**	(2.3)	**—**	—
	$216.8	$231.3	**$18.7**	$25.4

WPL	Defined Benefit Pension Plans 2017	Defined Benefit Pension Plans 2016	OPEB Plans 2017	OPEB Plans 2016
Change in benefit obligation:				
Net benefit obligation at January 1	**$529.2**	$505.9	**$88.9**	$89.7
Service cost	**4.9**	4.9	**1.9**	2.0
Interest cost	**21.8**	22.3	**3.4**	3.8
Plan participants' contributions	**—**	—	**1.4**	1.2
Actuarial loss	**38.3**	25.7	**4.1**	0.5
Gross benefits paid	**(34.4)**	(29.6)	**(9.3)**	(8.3)
Net benefit obligation at December 31	**559.8**	529.2	**90.4**	88.9
Change in plan assets:				
Fair value of plan assets at January 1	**389.7**	386.8	**18.6**	18.7
Actual return on plan assets	**59.6**	32.4	**1.2**	1.2
Employer contributions	**0.1**	0.1	**6.8**	5.8
Plan participants' contributions	**—**	—	**1.4**	1.2
Gross benefits paid	**(34.4)**	(29.6)	**(9.3)**	(8.3)
Fair value of plan assets at December 31	**415.0**	389.7	**18.7**	18.6
Under funded status at December 31	**($144.8)**	($139.5)	**($71.7)**	($70.3)

WPL	Defined Benefit Pension Plans 2017	Defined Benefit Pension Plans 2016	OPEB Plans 2017	OPEB Plans 2016
Amounts recognized on the balance sheets consist of:				
Non-current assets	**$—**	$—	**$2.9**	$2.7
Current liabilities	**(0.1)**	(0.1)	**(6.8)**	(6.4)
Pension and other benefit obligations	**(144.7)**	(139.4)	**(67.8)**	(66.6)
Net amounts recognized at December 31	**($144.8)**	($139.5)	**($71.7)**	($70.3)
Amounts recognized in Regulatory Assets consist of (refer to Note 2 for details):				
Net actuarial loss	**$224.7**	$236.1	**$23.6**	$21.5
Prior service credit	**(1.5)**	(1.4)	**(1.3)**	(1.5)
	$223.2	$234.7	**$22.3**	$20.0

Included in the following tables are accumulated benefit obligations, aggregate amounts applicable to defined benefit pension and OPEB plans with accumulated benefit obligations in excess of plan assets, as well as defined benefit pension plans with projected benefit obligations in excess of plan assets as of the December 31 measurement date (in millions):

Alliant Energy	Defined Benefit Pension Plans 2017	Defined Benefit Pension Plans 2016	OPEB Plans 2017	OPEB Plans 2016
Accumulated benefit obligations	**$1,269.0**	$1,201.5	**$222.3**	$220.1
Plans with accumulated benefit obligations in excess of plan assets:				
Accumulated benefit obligations	**1,269.0**	1,201.5	**222.3**	220.1
Fair value of plan assets	**950.7**	895.7	**111.1**	105.8
Plans with projected benefit obligations in excess of plan assets:				
Projected benefit obligations	**1,303.1**	1,244.3	**N/A**	N/A
Fair value of plan assets	**950.7**	895.7	**N/A**	N/A

IPL	Defined Benefit Pension Plans		OPEB Plans	
	2017	2016	**2017**	2016
Accumulated benefit obligations	**$573.1**	$546.7	**$89.4**	$90.1
Plans with accumulated benefit obligations in excess of plan assets:				
Accumulated benefit obligations	**573.1**	546.7	**89.4**	90.1
Fair value of plan assets	**443.7**	422.0	**72.9**	68.2
Plans with projected benefit obligations in excess of plan assets:				
Projected benefit obligations	**592.9**	570.4	**N/A**	N/A
Fair value of plan assets	**443.7**	422.0	**N/A**	N/A

WPL	Defined Benefit Pension Plans		OPEB Plans	
	2017	2016	**2017**	2016
Accumulated benefit obligations	**$548.1**	$513.2	**$90.4**	$88.9
Plans with accumulated benefit obligations in excess of plan assets:				
Accumulated benefit obligations	**548.1**	513.2	**90.4**	88.9
Fair value of plan assets	**415.0**	389.7	**18.7**	18.6
Plans with projected benefit obligations in excess of plan assets:				
Projected benefit obligations	**559.8**	529.2	**N/A**	N/A
Fair value of plan assets	**415.0**	389.7	**N/A**	N/A

In addition to the amounts recognized in regulatory assets in the above tables for IPL and WPL, regulatory assets were recognized for amounts associated with Corporate Services employees participating in other Alliant Energy sponsored benefit plans that were allocated to IPL and WPL at December 31 as follows (in millions):

	IPL		WPL	
	2017	2016	**2017**	2016
Regulatory assets	**$38.9**	$37.3	**$28.1**	$30.0

Estimated Future Employer Contributions and Benefit Payments - Estimated funding for the qualified and non-qualified defined benefit pension and OPEB plans for 2018 is as follows (in millions):

	Alliant Energy	IPL	WPL
Defined benefit pension plans (a)	$6.3	$4.4	$0.3
OPEB plans	9.0	2.0	6.8

(a) Alliant Energy sponsors several non-qualified defined benefit pension plans that cover certain current and former key employees of IPL and WPL. Alliant Energy allocates pension costs to IPL and WPL for these plans. In addition, IPL and WPL amounts reflect funding for their non-bargaining employees who are participants in the Alliant Energy and Corporate Services sponsored qualified and non-qualified defined benefit pension plans.

Expected benefit payments for the qualified and non-qualified defined benefit plans, which reflect expected future service, as appropriate, are as follows (in millions):

Alliant Energy	2018	2019	2020	2021	2022	2023 - 2027
Defined benefit pension benefits	$72.2	$73.9	$76.4	$77.1	$92.9	$398.2
OPEB	18.2	18.4	17.7	17.5	17.2	80.1
	$90.4	$92.3	$94.1	$94.6	$110.1	$478.3

IPL	2018	2019	2020	2021	2022	2023 - 2027
Defined benefit pension benefits	$33.9	$33.8	$36.5	$36.6	$37.6	$188.4
OPEB	7.1	7.1	7.2	7.1	7.0	32.6
	$41.0	$40.9	$43.7	$43.7	$44.6	$221.0

WPL	2018	2019	2020	2021	2022	2023 - 2027
Defined benefit pension benefits	$31.4	$32.0	$32.4	$32.4	$32.7	$167.8
OPEB	8.3	8.3	7.5	7.3	7.0	31.8
	$39.7	$40.3	$39.9	$39.7	$39.7	$199.6

Investment Strategy for Plan Assets - Investment strategies for defined benefit pension and OPEB plan assets combine preservation of principal and prudent risk-taking to protect the integrity of plan assets, in order to meet the obligations to plan participants while minimizing benefit costs over the long term. Investment risk of plan assets is mitigated through diversification, including broad U.S. equity, international equity and fixed income exposure, and global asset and risk parity strategies. Global asset and risk parity strategies include investments in global equity, global debt, commodities and currencies.

Defined Benefit Pension Plan Assets - The asset mix of defined benefit pension plans is governed by allocation targets. Historical performance results and future expectations suggest that equity securities will provide higher total investment returns than fixed income securities over a long-term investment horizon. Consistent with the goals of meeting obligations to plan participants and minimizing benefit costs over the long-term, the defined benefit pension plans have a long-term investment posture more heavily weighted toward equity holdings. The asset allocation is monitored regularly and appropriate steps are taken as needed to rebalance the assets within the prescribed ranges. An overlay management service is also used to help maintain target allocations and meet liquidity needs. The overlay manager is authorized to use derivative financial instruments to facilitate this service. For separately managed accounts, prohibited investments include, but may not be limited to, direct ownership of real estate, margin trading, oil and gas limited partnerships and securities of the managers' firms or affiliate firms.

At December 31, 2017, the current target ranges and actual allocations for the defined benefit pension plan assets were as follows:

	Target Range Allocation	Actual Allocation
Cash and equivalents	0% - 5%	3%
Equity securities - U.S.	11% - 41%	24%
Equity securities - international	14% - 34%	23%
Global asset securities	5% - 15%	10%
Risk parity securities	5% - 15%	10%
Fixed income securities	20% - 40%	30%

Other Postretirement Benefits Plan Assets - OPEB plan assets are comprised of specific assets within certain defined benefit pension plans (401(h) assets) as well as assets held in VEBA trusts. The investment strategy of the Corporate Services 401(h) assets mirrors those of the defined benefit pension plans, which are discussed above. For VEBA trusts with assets greater than $5 million and the WPL 401(h) assets, the mix among asset classes is governed by allocation targets. The asset allocation is monitored regularly and appropriate steps are taken as needed to rebalance the assets within the prescribed ranges. Mutual funds are used to achieve the desired diversification. At December 31, 2017, the current target ranges and actual allocations for VEBA trusts with assets greater than $5 million and the WPL 401(h) assets were as follows:

	Target Range Allocation	Actual Allocation
Cash and equivalents	0% - 5%	1%
Equity securities - U.S.	0% - 50%	26%
Equity securities - international	0% - 34%	10%
Fixed income securities	20% - 100%	63%

Fair Value Measurements - Fair value measurement accounting establishes three levels of fair value hierarchy that prioritize the inputs to valuation techniques used to measure fair value. Refer to Note 14 for discussion of levels within the fair value hierarchy. Level 1 items include investments in securities held in registered investment companies, treasury bills and directly held equity securities, which are valued at the closing price reported in the active market in which the securities are traded. Level 2 items include fixed income securities consisting of corporate and government bonds and agency obligations, which are valued at the closing price reported in the active market for similar assets in which the individual securities are traded or based on yields currently available on comparable securities of issuers with similar credit ratings. Certain investments that are measured at fair value using the net asset value practical expedient have not been classified in the fair value hierarchy. These fair value amounts are included in the tables below to reconcile the fair value hierarchy to the respective total plan assets.

At December 31, the fair values of qualified and non-qualified defined benefit pension plan assets were as follows (in millions):

Alliant Energy	2017 Fair Value	2017 Level 1	2017 Level 2	2017 Level 3	2016 Fair Value	2016 Level 1	2016 Level 2	2016 Level 3
Cash and equivalents	**$28.2**	**$4.5**	**$23.7**	**$—**	$30.4	$5.0	$25.4	$—
Equity securities - U.S.	**158.3**	**158.3**	**—**	**—**	183.6	183.6	—	—
Equity securities - international	**137.5**	**137.5**	**—**	**—**	97.4	97.4	—	—
Global asset securities	**49.4**	**49.4**	**—**	**—**	53.0	53.0	—	—
Fixed income securities	**135.9**	**55.8**	**80.1**	**—**	125.4	53.6	71.8	—
Total assets in fair value hierarchy	**509.3**	**$405.5**	**$103.8**	**$—**	489.8	$392.6	$97.2	$—
Assets measured at net asset value	**441.1**				405.9			
Accrued investment income	**1.0**				1.1			
Due to brokers, net (pending trades with brokers)	**(0.7)**				(1.1)			
Total pension plan assets	**$950.7**				$895.7			

IPL	2017 Fair Value	2017 Level 1	2017 Level 2	2017 Level 3	2016 Fair Value	2016 Level 1	2016 Level 2	2016 Level 3
Cash and equivalents	**$13.2**	**$2.2**	**$11.0**	**$—**	$14.4	$2.4	$12.0	$—
Equity securities - U.S.	**73.9**	**73.9**	**—**	**—**	86.5	86.5	—	—
Equity securities - international	**64.2**	**64.2**	**—**	**—**	45.9	45.9	—	—
Global asset securities	**23.0**	**23.0**	**—**	**—**	24.9	24.9	—	—
Fixed income securities	**63.4**	**26.0**	**37.4**	**—**	59.1	25.3	33.8	—
Total assets in fair value hierarchy	**237.7**	**$189.3**	**$48.4**	**$—**	230.8	$185.0	$45.8	$—
Assets measured at net asset value	**205.8**				191.2			
Accrued investment income	**0.5**				0.5			
Due to brokers, net (pending trades with brokers)	**(0.3)**				(0.5)			
Total pension plan assets	**$443.7**				$422.0			

WPL	2017 Fair Value	2017 Level 1	2017 Level 2	2017 Level 3	2016 Fair Value	2016 Level 1	2016 Level 2	2016 Level 3
Cash and equivalents	**$12.3**	**$2.0**	**$10.3**	**$—**	$13.3	$2.2	$11.1	$—
Equity securities - U.S.	**69.1**	**69.1**	**—**	**—**	79.9	79.9	—	—
Equity securities - international	**60.0**	**60.0**	**—**	**—**	42.4	42.4	—	—
Global asset securities	**21.6**	**21.6**	**—**	**—**	23.0	23.0	—	—
Fixed income securities	**59.3**	**24.3**	**35.0**	**—**	54.5	23.3	31.2	—
Total assets in fair value hierarchy	**222.3**	**$177.0**	**$45.3**	**$—**	213.1	$170.8	$42.3	$—
Assets measured at net asset value	**192.5**				176.6			
Accrued investment income	**0.5**				0.5			
Due to brokers, net (pending trades with brokers)	**(0.3)**				(0.5)			
Total pension plan assets	**$415.0**				$389.7			

At December 31, the fair values of OPEB plan assets were as follows (in millions):

Alliant Energy	2017 Fair Value	2017 Level 1	2017 Level 2	2017 Level 3	2016 Fair Value	2016 Level 1	2016 Level 2	2016 Level 3
Cash and equivalents	**$1.2**	**$0.7**	**$0.5**	**$—**	$3.5	$2.0	$1.5	$—
Equity securities - U.S.	**27.9**	**27.9**	**—**	**—**	22.5	22.5	—	—
Equity securities - international	**11.4**	**11.4**	**—**	**—**	13.5	13.5	—	—
Global asset securities	**0.4**	**0.4**	**—**	**—**	16.5	16.5	—	—
Fixed income securities	**66.6**	**66.0**	**0.6**	**—**	46.8	46.2	0.6	—
Total assets in fair value hierarchy	**107.5**	**$106.4**	**$1.1**	**$—**	102.8	$100.7	$2.1	$—
Assets measured at net asset value	**3.6**				3.0			
Total OPEB plan assets	**$111.1**				$105.8			

IPL	2017 Fair Value	2017 Level 1	2017 Level 2	2017 Level 3	2016 Fair Value	2016 Level 1	2016 Level 2	2016 Level 3
Cash and equivalents	**$0.3**	**$0.3**	**$—**	**$—**	$0.8	$0.8	$—	$—
Equity securities - U.S.	**22.3**	**22.3**	**—**	**—**	17.0	17.0	—	—
Equity securities - international	**7.5**	**7.5**	**—**	**—**	11.0	11.0	—	—
Global asset securities	**—**	**—**	**—**	**—**	7.0	7.0	—	—
Fixed income securities	**42.8**	**42.8**	**—**	**—**	32.4	32.4	—	—
Total OPEB plan assets	**$72.9**	**$72.9**	**$—**	**$—**	$68.2	$68.2	$—	$—

WPL	2017 Fair Value	2017 Level 1	2017 Level 2	2017 Level 3	2016 Fair Value	2016 Level 1	2016 Level 2	2016 Level 3
Cash and equivalents	**$0.6**	**$0.3**	**$0.3**	**$—**	$2.0	$0.7	$1.3	$—
Global asset securities	**—**	**—**	**—**	**—**	5.5	5.5	—	—
Fixed income securities	**18.1**	**18.1**	**—**	**—**	11.1	11.1	—	—
Total OPEB plan assets	**$18.7**	**$18.4**	**$0.3**	**$—**	$18.6	$17.3	$1.3	$—

For the various defined benefit pension and OPEB plans, Alliant Energy common stock represented less than 1% of assets directly held in the plans at December 31, 2017 and 2016.

401(k) Savings Plans - A significant number of employees participate in defined contribution retirement plans (401(k) savings plans). Alliant Energy common stock directly held by participants represented 11.5% and 12.6% of total assets in the 401(k) savings plans at December 31, 2017 and 2016, respectively. Costs related to the 401(k) savings plans, which are partially based on the participants' contributions and include allocated costs associated with Corporate Services employees for IPL and WPL, were as follows (in millions):

	Alliant Energy			IPL			WPL		
	2017	2016	2015	**2017**	2016	2015	**2017**	2016	2015
401(k) costs	**$24.8**	$23.6	$24.9	**$12.8**	$12.0	$12.7	**$11.1**	$10.7	$11.2

NOTE 12(b) Equity-based Compensation Plans - In 2015, Alliant Energy's shareowners approved the Amended and Restated OIP, which permits the grant of shares of Alliant Energy common stock, restricted stock, restricted stock units, performance shares, performance units, and other stock-based or cash-based awards to key employees. At December 31, 2017, performance shares, performance-contingent restricted stock and restricted stock units (performance- and time-vesting) were outstanding under the Amended and Restated OIP, and 7.1 million shares of Alliant Energy's common stock remained available for grants under the Amended and Restated OIP. Alliant Energy satisfies share payouts related to equity awards under the Amended and Restated OIP through the issuance of new shares of its common stock. Alliant Energy also has the DLIP, which permits the grant of cash-based long-term awards, including performance units, restricted cash awards and restricted units, to certain key employees. At December 31, 2017, performance units, performance-contingent cash awards and restricted units (performance- and time-vesting) were outstanding under the DLIP. There is no limit to the number of grants that can be made under the DLIP and Alliant Energy satisfies all payouts under the DLIP through cash payments. Nonvested awards generally do not have non-forfeitable rights to dividends or dividend equivalents when dividends are paid to common shareowners.

A summary of compensation expense, including amounts allocated to IPL and WPL, and the related income tax benefits recognized for share-based compensation awards was as follows (in millions):

	Alliant Energy			IPL			WPL		
	2017	2016	2015	**2017**	2016	2015	**2017**	2016	2015
Compensation expense	**$15.1**	$18.0	$10.7	**$8.3**	$9.5	$5.7	**$6.4**	$7.9	$4.7
Income tax benefits	**6.2**	7.4	4.4	**3.4**	4.0	2.4	**2.6**	3.2	1.9

As of December 31, 2017, Alliant Energy's, IPL's and WPL's total unrecognized compensation cost related to share-based compensation awards was $5.6 million, $3.1 million and $2.2 million, respectively, which is expected to be recognized over a weighted average period of between one and two years. Share-based compensation expense is recognized on a straight-line basis over the requisite service periods and is primarily recorded in "Other operation and maintenance" in the income statements.

Performance Shares and Performance Units - Payouts of performance shares under the Amended and Restated OIP and performance units under the DLIP to key employees are contingent upon achievement over three-year periods of specified performance criteria, which currently include metrics of total shareowner return relative to an investor-owned utility peer group. Performance shares can be paid out in shares of Alliant Energy's common stock, cash or a combination of cash and stock. Performance units must be paid out in cash. Alliant Energy assumes it will make future payouts of its performance shares and performance units in cash; therefore, performance shares and performance units are accounted for as liability awards. A summary of the performance shares and performance units activity, with amounts representing the target number of awards, was as follows:

	Performance Shares			Performance Units		
	2017	2016	2015	**2017**	2016	2015
Nonvested awards, January 1	**257,599**	288,430	288,848	**93,320**	116,412	127,330
Granted	**65,350**	68,585	90,806	**21,558**	23,918	35,674
Vested	**(99,438)**	(98,186)	(91,224)	**(37,395)**	(42,760)	(45,690)
Forfeited	—	(1,230)	—	**(5,746)**	(4,250)	(902)
Nonvested awards, December 31	**223,511**	257,599	288,430	**71,737**	93,320	116,412

Granted Awards - Each performance share's value is based on the closing market price of one share of Alliant Energy's common stock at the end of the performance period. For performance units granted in 2017 and 2016, the value is based on the closing market price of one share of Alliant Energy's common stock at the end of the performance period. For performance units granted in 2015, the value is based on the closing market price of one share of Alliant Energy's common stock on the grant date of the award. The actual payout for performance shares and performance units is dependent upon actual performance and may range from zero to 200% of the target number of awards. Compensation expense for performance shares and performance units is recorded ratably over the performance period based on the fair value of the awards at each reporting period.

Vested Awards - Certain performance shares and performance units vested, resulting in payouts (a combination of cash and common stock for the performance shares and cash only for the performance units) as follows:

	Performance Shares			Performance Units		
	2017	2016	2015	**2017**	2016	2015
	2014 Grant	2013 Grant	2012 Grant	**2014 Grant**	2013 Grant	2012 Grant
Performance awards vested	**99,438**	98,186	91,224	**37,395**	42,760	45,690
Percentage of target number of performance awards	**147.5%**	165.0%	167.5%	**147.5%**	165.0%	167.5%
Aggregate payout value (in millions)	**$5.6**	$5.1	$5.1	**$1.5**	$1.7	$1.6
Payout - cash (in millions)	**$5.1**	$2.9	$3.2	**$1.5**	$1.7	$1.6
Payout - common stock shares issued	**5,185**	22,408	21,950	**N/A**	N/A	N/A

Fair Value of Awards - Information related to fair values of nonvested performance shares and performance units at December 31, 2017, by year of grant, were as follows:

	Performance Shares			Performance Units		
	2017 Grant	2016 Grant	2015 Grant	2017 Grant	2016 Grant	2015 Grant
Nonvested awards at target	65,350	67,355	90,806	18,600	21,227	31,910
Alliant Energy common stock closing price on December 29, 2017	$42.61	$42.61	$42.61	$42.61	$42.61	N/A
Alliant Energy common stock closing price on grant date	N/A	N/A	N/A	N/A	N/A	$32.55
Estimated payout percentage based on performance criteria	105%	150%	138%	105%	150%	138%
Fair values of each nonvested award	$44.74	$63.92	$58.80	$44.74	$63.92	$44.92

Performance Restricted Stock Units and Performance Restricted Units - Alliant Energy granted new types of share-based compensation awards to key employees beginning in 2016 referred to as performance restricted stock units under the Amended and Restated OIP, and performance restricted units and key employee performance restricted units under the DLIP. Payouts of these units are based on the achievement of certain performance targets (currently specified growth of consolidated income from continuing operations) during a three-year performance period. The actual number of units that will be paid out upon vesting is dependent upon actual performance and may range from zero to 200% of the target number of units. If performance targets are not met during the performance period, these units are forfeited. As of December 31, 2017, the amount of nonvested performance restricted units and key employee performance restricted units was not material.

Performance Restricted Stock Units - Performance restricted stock units generally must be paid out in shares and are accounted for as equity awards. Each performance restricted stock unit's value is based on the closing market price of one share of Alliant Energy's common stock on the grant date of the award. Compensation expense is recorded ratably over the performance period based on a probability assessment of payouts for the awards at each reporting period. A summary of the performance restricted stock units activity, with amounts representing the target number of units, was as follows:

	2017		2016	
	Units	**Weighted Average Grant Date Fair Value**	Units	Weighted Average Grant Date Fair Value
Nonvested units, January 1	**67,355**	**$33.96**	—	$—
Granted	**65,350**	**39.12**	68,585	33.96
Forfeited	**—**	**—**	(1,230)	33.90
Nonvested units, December 31	**132,705**	**36.50**	67,355	33.96

Restricted Stock Units and Restricted Units - Alliant Energy granted new types of share-based compensation awards to key employees beginning in 2016 referred to as restricted stock units under the Amended and Restated OIP and restricted units under the DLIP. Payouts of these units are based on the expiration of a three-year time-vesting period. Each restricted stock unit's value is based on the closing market price of one share of Alliant Energy's common stock at the end of the time-vesting period. Compensation expense is recorded ratably over the performance period based on the fair value of the awards at each reporting period. Restricted stock units can be paid out in shares of Alliant Energy common stock, cash or a combination of cash and stock. Alliant Energy assumes it will make future payouts of its restricted stock units in cash; therefore, restricted stock units are accounted for as liability awards. As of December 31, 2017, the amount of nonvested restricted units was not material. A summary of the restricted stock units activity was as follows:

	2017	2016
Nonvested units, January 1	**57,736**	—
Granted	**56,013**	58,790
Forfeited	**—**	(1,054)
Nonvested units, December 31	**113,749**	57,736

Performance-Contingent Restricted Stock and Performance-Contingent Cash Awards - As of December 31, 2017, the amount of nonvested performance-contingent restricted stock and performance-contingent cash awards was not material.

NOTE 12(c) Deferred Compensation Plan - Alliant Energy maintains a DCP under which key employees may defer up to 100% of base salary and short-term cash incentive compensation and directors may elect to defer all or part of their retainer and committee fees. Key employees who have made the maximum allowed contribution to the Alliant Energy 401(k) Savings Plan may receive an additional credit to the DCP. Key employees and directors may elect to have their deferrals credited to a company stock account, an interest account, equity accounts or mutual fund accounts based on certain benchmark funds.

Company Stock Account - The DCP does not permit diversification of deferrals credited to the company stock account and all distributions from participants' company stock accounts are made in the form of shares of Alliant Energy common stock. The deferred compensation obligations for participants' company stock accounts are recorded in "Additional paid-in capital" and the shares of Alliant Energy common stock held in a rabbi trust to satisfy this obligation are recorded in "Shares in deferred compensation trust" on Alliant Energy's balance sheets. At December 31, the carrying value of the deferred compensation obligation for the company stock account and the shares in the deferred compensation trust based on the historical value of the shares of Alliant Energy common stock contributed to the rabbi trust, and the fair market value of the shares held in the rabbi trust, were as follows (in millions):

	2017	2016
Carrying value	**$11.1**	$10.0
Fair market value	**19.7**	16.7

Interest, Equity and Mutual Fund Accounts - Distributions from participants' interest, equity and mutual fund accounts are in the form of cash payments. The deferred compensation obligations for participants' interest, equity and mutual fund accounts are recorded in "Pension and other benefit obligations" on the balance sheets. At December 31, 2017 and 2016, the carrying value of Alliant Energy's deferred compensation obligations for participants' interest, equity and mutual fund accounts, which approximates fair market value, was $21.8 million and $19.4 million, respectively.

NOTE 13. ASSET RETIREMENT OBLIGATIONS

Recognized AROs relate to legal obligations for the removal, closure or dismantlement of several assets including, but not limited to, ash ponds, wind farms, active ash landfills, solar generation and above ground storage tanks. Recognized AROs also include legal obligations for the management and final disposition of asbestos, polychlorinated biphenyls and lead-based paint. AROs are recorded in "Other current liabilities" and "Other liabilities" on the balance sheets. Refer to Note 2 for information regarding regulatory assets related to AROs. A reconciliation of the changes in AROs associated with long-lived assets is as follows (in millions):

	Alliant Energy		IPL		WPL	
	2017	2016	**2017**	2016	**2017**	2016
Balance, January 1	**$195.7**	$214.0	**$124.7**	$132.9	**$61.4**	$71.9
Revisions in estimated cash flows	**4.3**	(13.3)	**7.0**	(5.8)	**(2.7)**	(7.5)
Liabilities settled	**(23.5)**	(14.0)	**(13.1)**	(6.8)	**(10.4)**	(7.2)
Liabilities incurred	**2.0**	2.6	**11.7**	0.7	—	1.9
Accretion expense	**6.0**	6.4	**3.8**	3.7	**2.1**	2.3
Balance, December 31	**$184.5**	$195.7	**$134.1**	$124.7	**$50.4**	$61.4

In addition, certain AROs related to EGU assets have not been recognized. Due to an indeterminate remediation date, the fair values of the AROs for these assets cannot be currently estimated. A liability for these AROs will be recorded when fair value is determinable. Removal costs of these EGUs are being recovered in rates and are recorded in regulatory liabilities.

NOTE 14. FAIR VALUE MEASUREMENTS

Valuation Hierarchy - Fair value measurement accounting establishes three levels of fair value hierarchy that prioritize the inputs to valuation techniques used to measure fair value. Level 1 pricing inputs are quoted prices available in active markets for identical assets or liabilities as of the reporting date. Level 2 pricing inputs are quoted prices for similar assets or liabilities in active markets or quoted prices for identical or similar assets or liabilities in markets that are not active as of the reporting date. Level 3 pricing inputs are unobservable inputs for assets or liabilities for which little or no market data exist and require significant management judgment or estimation.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability.

Valuation Techniques -

Derivative assets and derivative liabilities - Derivative instruments are used for risk management purposes to mitigate exposures to fluctuations in certain commodity prices, transmission congestion costs and rail transportation costs. Risk policies are maintained that govern the use of such derivative instruments. Derivative instruments were not designated as hedging instruments and included the following:

Risk management purpose	Type of instrument
Mitigate pricing volatility for:	
Electricity purchased to supply customers	Electric physical forward contracts (WPL)
Fuel used to supply natural gas-fired EGUs	Natural gas swap, options and physical forward contracts (IPL and WPL)
Natural gas supplied to retail customers	Natural gas options and physical forward contracts (IPL and WPL)
	Natural gas swap contracts (IPL)
Fuel used at coal-fired EGUs	Coal physical forward contracts (IPL and WPL)
Optimize the value of natural gas pipeline capacity	Natural gas physical forward contracts (IPL and WPL)
	Natural gas swap contracts (IPL)
Manage transmission congestion costs	FTRs (IPL and WPL)
Manage rail transportation costs	Diesel fuel swap contracts (WPL)

Swap, option and physical forward commodity contracts were non-exchange-based derivative instruments and were valued using indicative price quotations from a pricing vendor that provides daily exchange forward price settlements, from broker or dealer quotations, from market publications or from on-line exchanges. The indicative price quotations reflected the average of the bid-ask mid-point prices and were obtained from sources believed to provide the most liquid market for the commodity. A portion of these indicative price quotations were corroborated using quoted prices for similar assets or

liabilities in active markets and categorized derivative instruments based on such indicative price quotations as Level 2. Commodity contracts that were valued using indicative price quotations based on significant assumptions such as seasonal or monthly shaping and indicative price quotations that could not be readily corroborated were categorized as Level 3. Swap, option and physical forward commodity contracts were predominately at liquid trading points. FTRs were valued using auction prices and were categorized as Level 3. Refer to Note 15 for additional details of derivative assets and derivative liabilities.

Deferred proceeds (sales of receivables) - The fair value of IPL's deferred proceeds related to its sales of accounts receivable program was calculated each reporting date using the cost approach valuation technique. The fair value represents the carrying amount of receivables sold less the allowance for doubtful accounts associated with the receivables sold and cash amounts received from the receivables sold due to the short-term nature of the collection period. These inputs were considered unobservable and deferred proceeds were categorized as Level 3. Deferred proceeds represent IPL's maximum exposure to loss related to the receivables sold. Refer to Note 5(b) for additional information regarding deferred proceeds.

Long-term debt (including current maturities) - The fair value of long-term debt instruments was based on quoted market prices for similar liabilities at each reporting date or on a discounted cash flow methodology, which utilizes assumptions of current market pricing curves at each reporting date, and was substantially classified as Level 2. Refer to Note 9(b) for additional information regarding long-term debt.

Cumulative preferred stock - The fair value of IPL's 5.1% cumulative preferred stock was based on its closing market price quoted by the New York Stock Exchange at each reporting date, and was classified as Level 1. Refer to Note 8 for additional information regarding cumulative preferred stock.

Fair Value of Financial Instruments - The carrying amounts of current assets and current liabilities approximate fair value because of the short maturity of such financial instruments. Carrying amounts and the related estimated fair values of other financial instruments at December 31 were as follows (in millions):

Alliant Energy	2017					2016				
		Fair Value					Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total	Carrying Amount	Level 1	Level 2	Level 3	Total
Assets:										
Derivatives	**$25.1**	**$—**	**$4.1**	**$21.0**	**$25.1**	$41.4	$—	$4.6	$36.8	$41.4
Deferred proceeds	**222.1**	**—**	**—**	**222.1**	**222.1**	211.1	—	—	211.1	211.1
Liabilities and equity:										
Derivatives	**41.7**	**—**	**8.5**	**33.2**	**41.7**	28.6	—	0.5	28.1	28.6
Long-term debt (incl. current maturities)	**4,866.3**	**—**	**5,444.6**	**2.9**	**5,447.5**	4,320.2	—	4,795.7	3.3	4,799.0
Cumulative preferred stock of IPL	**200.0**	**203.8**	**—**	**—**	**203.8**	200.0	194.8	—	—	194.8

IPL	2017					2016				
		Fair Value					Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total	Carrying Amount	Level 1	Level 2	Level 3	Total
Assets:										
Derivatives	**$17.1**	**$—**	**$2.0**	**$15.1**	**$17.1**	$20.8	$—	$2.8	$18.0	$20.8
Deferred proceeds	**222.1**	**—**	**—**	**222.1**	**222.1**	211.1	—	—	211.1	211.1
Liabilities and equity:										
Derivatives	**19.4**	**—**	**2.9**	**16.5**	**19.4**	8.3	—	0.4	7.9	8.3
Long-term debt (incl. current maturities)	**2,406.0**	**—**	**2,665.7**	**—**	**2,665.7**	2,153.5	—	2,352.3	—	2,352.3
Cumulative preferred stock	**200.0**	**203.8**	**—**	**—**	**203.8**	200.0	194.8	—	—	194.8

WPL	2017					2016				
		Fair Value					Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total	Carrying Amount	Level 1	Level 2	Level 3	Total
Assets:										
Derivatives	**$8.0**	**$—**	**$2.1**	**$5.9**	**$8.0**	$20.6	$—	$1.8	$18.8	$20.6
Liabilities and equity:										
Derivatives	**22.3**	**—**	**5.6**	**16.7**	**22.3**	20.3	—	0.1	20.2	20.3
Long-term debt	**1,833.4**	**—**	**2,147.9**	**—**	**2,147.9**	1,535.2	—	1,807.4	—	1,807.4

Information for fair value measurements using significant unobservable inputs (Level 3 inputs) was as follows (in millions):

Alliant Energy	Commodity Contract Derivative Assets and (Liabilities), net		Deferred Proceeds	
	2017	2016	**2017**	2016
Beginning balance, January 1	**$8.7**	($32.7)	**$211.1**	$172.0
Total net gains (losses) included in changes in net assets (realized/unrealized)	**(32.9)**	30.7	**—**	—
Transfers into Level 3	**—**	0.9	**—**	—
Transfers out of Level 3	**12.2**	1.2	**—**	—
Purchases	**28.3**	22.0	**—**	—
Sales	**(0.3)**	(1.0)	**—**	—
Settlements (a)	**(28.2)**	(12.4)	**11.0**	39.1
Ending balance, December 31	**($12.2)**	$8.7	**$222.1**	$211.1
The amount of total net gains (losses) for the period included in changes in net assets attributable to the change in unrealized gains (losses) relating to assets and liabilities held at December 31	**($31.0)**	$32.7	**$—**	$—

IPL	Commodity Contract Derivative Assets and (Liabilities), net		Deferred Proceeds	
	2017	2016	**2017**	2016
Beginning balance, January 1	**$10.1**	($1.9)	**$211.1**	$172.0
Total net gains (losses) included in changes in net assets (realized/unrealized)	**(14.8)**	7.3	**—**	—
Transfers into Level 3	**—**	0.5	**—**	—
Transfers out of Level 3	**3.1**	0.2	**—**	—
Purchases	**24.6**	20.6	**—**	—
Sales	**(0.2)**	(1.0)	**—**	—
Settlements (a)	**(24.2)**	(15.6)	**11.0**	39.1
Ending balance, December 31	**($1.4)**	$10.1	**$222.1**	$211.1
The amount of total net gains (losses) for the period included in changes in net assets attributable to the change in unrealized gains (losses) relating to assets and liabilities held at December 31	**($13.5)**	$8.5	**$—**	$—

WPL	Commodity Contract Derivative Assets and (Liabilities), net	
	2017	2016
Beginning balance, January 1	**($1.4)**	($30.8)
Total net gains (losses) included in changes in net assets (realized/unrealized)	**(18.1)**	23.4
Transfers into Level 3	**—**	0.4
Transfers out of Level 3	**9.1**	1.0
Purchases	**3.7**	1.4
Sales	**(0.1)**	—
Settlements	**(4.0)**	3.2
Ending balance, December 31	**($10.8)**	($1.4)
The amount of total net gains (losses) for the period included in changes in net assets attributable to the change in unrealized gains (losses) relating to assets and liabilities held at December 31	**($17.5)**	$24.2

(a) Settlements related to deferred proceeds are due to the change in the carrying amount of receivables sold less the allowance for doubtful accounts associated with the receivables sold and cash amounts received from the receivables sold.

Commodity Contracts - The fair value of electric, natural gas, coal and diesel fuel commodity contracts categorized as Level 3 was recognized as net derivative assets (liabilities) at December 31 as follows (in millions):

	Alliant Energy		IPL		WPL	
	Excluding FTRs	FTRs	Excluding FTRs	FTRs	Excluding FTRs	FTRs
2017	**($23.5)**	**$11.3**	**($11.5)**	**$10.1**	**($12.0)**	**$1.2**
2016	(2.3)	11.0	0.1	10.0	(2.4)	1.0

NOTE 15. DERIVATIVE INSTRUMENTS

Commodity Derivatives -

Purpose - Derivative instruments are used for risk management purposes to mitigate exposures to fluctuations in certain commodity prices, transmission congestion costs and rail transportation costs. Refer to Note 14 for detailed discussion of derivative instruments.

Notional Amounts - As of December 31, 2017, gross notional amounts and settlement/delivery years related to outstanding swap contracts, option contracts, physical forward contracts and FTRs that were accounted for as commodity derivative instruments were as follows (units in thousands):

	Electricity		FTRs		Natural Gas		Coal		Diesel Fuel	
	MWhs	Years	MWhs	Years	Dths	Years	Tons	Years	Gallons	Years
Alliant Energy	1,314	2018	8,970	2018	170,463	2018-2026	8,177	2018-2020	6,552	2018-2019
IPL	—	—	5,886	2018	72,662	2018-2026	3,339	2018-2020	—	—
WPL	1,314	2018	3,084	2018	97,801	2018-2026	4,838	2018-2020	6,552	2018-2019

Financial Statement Presentation - Derivative instruments are recorded at fair value each reporting date on the balance sheet as assets or liabilities. At December 31, the fair values of current derivative assets are included in "Other current assets," non-current derivative assets are included in "Deferred charges and other," current derivative liabilities are included in "Other current liabilities" and non-current derivative liabilities are included in "Other liabilities" on the balance sheets as follows (in millions):

	Alliant Energy		IPL		WPL	
	2017	2016	**2017**	2016	**2017**	2016
Current derivative assets	**$21.1**	$29.4	**$15.8**	$19.1	**$5.3**	$10.3
Non-current derivative assets	**4.0**	12.0	**1.3**	1.7	**2.7**	10.3
Current derivative liabilities	**18.7**	13.3	**5.0**	2.7	**13.7**	10.6
Non-current derivative liabilities	**23.0**	15.3	**14.4**	5.6	**8.6**	9.7

Credit Risk-related Contingent Features - Various agreements contain credit risk-related contingent features, including requirements to maintain certain credit ratings and/or limitations on liability positions under the agreements based on credit ratings. Certain of these agreements with credit risk-related contingency features are accounted for as derivative instruments. In the event of a material change in creditworthiness or if liability positions exceed certain contractual limits, credit support may need to be provided in the form of letters of credit or cash collateral up to the amount of exposure under the contracts, or the contracts may need to be unwound and underlying liability positions paid. At December 31, 2017 and 2016, the aggregate fair value of all derivative instruments with credit risk-related contingent features in a net liability position was not materially different than amounts that would be required to be posted as credit support to counterparties by Alliant Energy, IPL or WPL if the most restrictive credit risk-related contingent features for derivative agreements in a net liability position were triggered.

Balance Sheet Offsetting - The fair value amounts of derivative instruments subject to a master netting arrangement are not netted by counterparty on the balance sheets. However, if the fair value amounts of derivative instruments by counterparty were netted, amounts would not be materially different from gross amounts of derivative assets and derivative liabilities at December 31, 2017 and 2016. Fair value amounts recognized for the right to reclaim cash collateral (receivable) or the obligation to return cash collateral (payable) are not offset against fair value amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement.

NOTE 16. COMMITMENTS AND CONTINGENCIES

NOTE 16(a) Capital Purchase Obligations - Various contractual obligations contain minimum future commitments related to capital expenditures for certain construction projects. IPL's projects include the expansion of wind generation and installation of an SCR system at Ottumwa Unit 1 to reduce NOx emissions at the EGU. WPL's projects include West Riverside. At December 31, 2017, Alliant Energy's, IPL's and WPL's minimum future commitments related to certain contractual obligations for these projects were $82 million, $15 million and $67 million, respectively.

NOTE 16(b) Other Purchase Obligations - Various commodity supply, transportation and storage contracts help meet obligations to provide electricity and natural gas to utility customers. In addition, there are various purchase obligations associated with other goods and services. At December 31, 2017, minimum future commitments related to these purchase obligations were as follows (in millions):

Alliant Energy	2018	2019	2020	2021	2022	Thereafter	Total
Purchased power (a)	$188	$159	$135	$149	$140	$461	$1,232
Natural gas	229	140	130	110	84	253	946
Coal (b)	107	59	21	5	—	—	192
Other (c)	21	6	6	3	2	2	40
	$545	$364	$292	$267	$226	$716	$2,410

IPL	2018	2019	2020	2021	2022	Thereafter	Total
Purchased power (a)	$130	$144	$135	$149	$140	$461	$1,159
Natural gas	126	58	44	32	22	102	384
Coal (b)	51	31	11	5	—	—	98
Other (c)	15	3	3	3	2	2	28
	$322	$236	$193	$189	$164	$565	$1,669

WPL	2018	2019	2020	2021	2022	Thereafter	Total
Purchased power (a)	$58	$15	$—	$—	$—	$—	$73
Natural gas	103	82	86	78	62	151	562
Coal (b)	56	28	10	—	—	—	94
Other (c)	5	1	—	—	—	—	6
	$222	$126	$96	$78	$62	$151	$735

(a) Includes payments required by PPAs for capacity rights and minimum quantities of MWhs required to be purchased.
(b) Corporate Services entered into system-wide coal contracts on behalf of IPL and WPL that include minimum future commitments. These commitments were assigned to IPL and WPL based on information available as of December 31, 2017 regarding expected future usage, which is subject to change.
(c) Includes individual commitments incurred during the normal course of business that exceeded $1 million at December 31, 2017.

Certain contracts are considered leases and are therefore not included here, but are included in Note 10.

NOTE 16(c) Legal Proceedings -

Flood Damage Claims - In 2013, several plaintiffs purporting to represent a class of residential and commercial property owners filed a complaint against CRANDIC, Alliant Energy and various other defendants in the Iowa District Court for Linn County. Plaintiffs assert claims of negligence and strict liability based on their allegations that CRANDIC (along with other defendants) caused or exacerbated flooding of the Cedar River in June 2008. In February 2016, the Iowa District Court for Linn County ruled in favor of Alliant Energy and CRANDIC and dismissed all claims against them, resulting in no loss. In August 2016, the Iowa District Court for Linn County dismissed all claims against the remaining defendants. In September 2016, plaintiffs filed a notice of appeal with the Supreme Court of Iowa. Alliant Energy does not currently believe any material losses for this complaint are both probable and reasonably estimated, and therefore has not recognized any material loss contingency amounts as of December 31, 2017.

Other - Alliant Energy, IPL and WPL are involved in other legal and administrative proceedings before various courts and agencies with respect to matters arising in the ordinary course of business. Although unable to predict the outcome of these matters, Alliant Energy, IPL and WPL believe that appropriate reserves have been established and final disposition of these actions will not have a material effect on their financial condition or results of operations.

NOTE 16(d) Guarantees and Indemnifications -

Whiting Petroleum - In 2004, Alliant Energy sold its remaining interest in Whiting Petroleum. Whiting Petroleum is an independent oil and gas company. Alliant Energy Resources, LLC, as the successor to a predecessor entity that owned Whiting Petroleum, and a wholly-owned subsidiary of AEF, continues to guarantee the partnership obligations of an affiliate of Whiting Petroleum under general partnership agreements in the oil and gas industry, including with respect to the future abandonment of certain platforms off the coast of California and related onshore plant and equipment owned by the partnerships. The guarantees do not include a maximum limit. As of December 31, 2017, the present value of the abandonment obligations is estimated at $33 million. Alliant Energy is not aware of any material liabilities related to these guarantees of which it is probable that Alliant Energy Resources, LLC will be obligated to pay and therefore has not recognized any material liabilities related to this guarantee as of December 31, 2017.

Non-utility Wind Investment in Oklahoma - In July 2017, a wholly-owned subsidiary of AEF acquired a cash equity ownership interest in a non-utility wind farm located in Oklahoma. The wind farm provides electricity to a third-party under a long-term PPA. Alliant Energy provided a parent guarantee of its subsidiary's indemnification obligations under the related operating agreement and PPA. Alliant Energy's obligations under the operating agreement were $98 million as of December 31, 2017 and will reduce annually until expiring in July 2047. Alliant Energy's obligations under the PPA are subject to a maximum limit of $17 million and expire in December 2031, subject to potential extension. Alliant Energy is not aware of any material liabilities related to this guarantee that it is probable that it will be obligated to pay and therefore has not recognized any material liabilities related to this guarantee as of December 31, 2017. Refer to Note 6(a) for further discussion of the non-utility wind investment.

IPL's Minnesota Electric Distribution Assets - IPL provided indemnifications associated with the July 2015 sale of its Minnesota electric distribution assets for losses resulting from potential breach of IPL's representations, warranties and obligations under the sale agreement. Alliant Energy and IPL believe the likelihood of having to make any material cash payments under these indemnifications is remote. IPL has not recorded any material liabilities related to these indemnifications as of December 31, 2017. The general terms of the indemnifications provided by IPL included a maximum limit of $17 million and expire in October 2020. Refer to Note 3 for further discussion of the sale of IPL's Minnesota electric distribution assets.

NOTE 16(e) Environmental Matters - Alliant Energy, IPL and WPL are subject to environmental regulations as a result of their current and past operations. These regulations are designed to protect public health and the environment and have resulted in compliance, remediation, containment and monitoring obligations, which are recorded as current and non-current environmental liabilities. Substantially all of the environmental liabilities recorded on the balance sheets relate to MGP sites.

MGP Sites - IPL and WPL have current or previous ownership interests in various sites that are previously associated with the production of gas for which IPL and WPL have, or may have in the future, liability for investigation, remediation and monitoring costs. IPL and WPL are working pursuant to the requirements of various federal and state agencies to investigate, mitigate, prevent and remediate, where necessary, the environmental impacts to property, including natural resources, at and around these former MGP sites in order to protect public health and the environment. At December 31, 2017, estimated future costs expected to be incurred for the investigation, remediation and monitoring of the MGP sites, as well as environmental liabilities recorded on the balance sheets for these sites, which are not discounted, were as follows (in millions). At December 31, 2017, such amounts for WPL were not material.

	Alliant Energy	IPL
Range of estimated future costs	$11 - $30	$9 - $27
Current and non-current environmental liabilities	15	13

WPL Consent Decree - In 2013, the U.S. District Court for the Western District of Wisconsin approved a Consent Decree that WPL, along with the other owners of Edgewater and Columbia, entered into with the EPA and the Sierra Club, thereby resolving claims against WPL. Such claims included allegations that the owners of Edgewater, Nelson Dewey and Columbia violated the Prevention of Significant Deterioration program requirements, Title V Operating Permit requirements of the CAA and the Wisconsin State Implementation Plan designed to implement the CAA.

WPL has completed various requirements under the Consent Decree. WPL's remaining requirements include installing an SCR system at Columbia Unit 2 and fuel switching or retiring Edgewater Unit 4 by December 31, 2018. The Consent Decree also establishes SO2, NOx and particulate matter emission rate limits for Columbia Units 1 and 2, and Edgewater Units 4 and 5. In addition, the Consent Decree includes annual plant-wide SO2 and NOx emission caps for Columbia and Edgewater. Alliant Energy and WPL currently expect to recover material costs incurred by WPL related to compliance with the terms of the Consent Decree from WPL's electric customers.

IPL Consent Decree - In 2015, the U.S. District Court for the Northern District of Iowa approved a Consent Decree that IPL entered into with the EPA, the Sierra Club, the State of Iowa and Linn County in Iowa, thereby resolving potential CAA issues associated with emissions from IPL's coal-fired generating facilities in Iowa. IPL has completed various requirements under the Consent Decree. IPL's remaining requirements include installing an SCR system or equivalent NOx reduction system at Ottumwa by December 31, 2019, and fuel switching or retiring Burlington by December 31, 2021 and Prairie Creek Units 1 and 3 by December 31, 2025.

The Consent Decree also establishes SO2, NOx and particulate matter emission rate limits with varying averaging times for Burlington, Lansing, M.L. Kapp, Ottumwa and Prairie Creek. In addition, the Consent Decree includes calendar-year SO2 and NOx emission caps for Prairie Creek, and calendar-year SO2 and NOx emission caps in aggregate for Burlington, Lansing, M.L. Kapp, Ottumwa and Prairie Creek. Alliant Energy and IPL currently expect to recover material costs incurred by IPL related to compliance with the terms of the Consent Decree from IPL's electric customers.

Other Environmental Contingencies - In addition to the environmental liabilities discussed above, various environmental rules are monitored that may have a significant impact on future operations. Several of these environmental rules are subject to legal challenges, reconsideration and/or other uncertainties. Given uncertainties regarding the outcome, timing and compliance plans for these environmental matters, the complete financial impact of each of these rules is not able to be determined; however future capital investments and/or modifications to EGUs to comply with certain of these rules could be significant. Specific current, proposed or potential environmental matters include, among others: CSAPR, Effluent Limitation Guidelines, CCR Rule, and various legislation and EPA regulations to monitor and regulate the emission of GHG, including carbon emissions from new (CAA Section 111(b)) and existing (CAA Section 111(d)) fossil-fueled EGUs.

NOTE 16(f) Credit Risk - IPL provides retail electric and gas services in Iowa and wholesale electric service in Minnesota, Illinois and Iowa. WPL provides retail electric and gas services and wholesale electric service in Wisconsin. The geographic concentration of IPL's and WPL's customers did not contribute significantly to overall credit risk exposure. In addition, as a result of a diverse customer base, IPL and WPL did not have any significant credit risk concentration for receivables arising from the sale of electricity or gas services.

Alliant Energy, IPL and WPL are subject to credit risk related to the ability of counterparties to meet their contractual payment obligations or the potential non-performance of counterparties to deliver contracted commodities and other goods or services at the contracted price. Credit policies are maintained to mitigate credit risk. These credit policies include evaluation of the financial condition of certain counterparties, use of credit risk-related contingent provisions in certain agreements that require credit support from counterparties not meeting specific criteria, diversification of counterparties to reduce concentrations of credit risk and the use of standardized agreements that facilitate the netting of cash flows associated with certain counterparties. Based on these credit policies and counterparty diversification, as well as utility cost recovery mechanisms, it is unlikely that counterparty non-performance would have a material effect on financial condition or results of operations. However, there is no assurance that these items will protect against all losses from counterparty non-performance.

Refer to Notes 5(a) and 15 for details of allowances for doubtful accounts and credit risk-related contingent features, respectively.

NOTE 17. SEGMENTS OF BUSINESS

In the fourth quarter of 2017, Alliant Energy and WPL modified the segment reporting related to their ATC Investment, consistent with information used by their chief operating decision maker to evaluate performance and allocate resources. As of December 31, 2017, the ATC Investment is no longer included in Alliant Energy's utility electric operations reportable segment or WPL's electric operations reportable segment. As a result, all prior period amounts impacted by this change were reclassified to conform to the new presentation. Alliant Energy's related amounts were reclassified from "Electric Utility" to "ATC Investment, Non-Utility, Parent and Other." WPL's related amounts were reclassified from "Electric" to "Other."

Alliant Energy - Alliant Energy's principal businesses as of December 31, 2017 are:

- **Utility -** includes the operations of IPL and WPL, which primarily serve retail customers in Iowa and Wisconsin. The utility business has three reportable segments: a) utility electric operations; b) utility gas operations; and c) utility other, which includes steam operations and the unallocated portions of the utility business. Various line items in the following tables are not allocated to the electric and gas segments for management reporting purposes, and therefore, are included only in "Total Utility."
- **ATC Investment, Non-utility, Parent and Other -** includes the operations of AEF and its subsidiaries, Corporate Services, the Alliant Energy parent company, and any Alliant Energy parent company consolidating adjustments. AEF is comprised of Alliant Energy's ATC Investment, Transportation, a non-utility wind investment, the Sheboygan Falls Energy Facility and other non-utility investments, which are described in Note 1(a).

Alliant Energy's administrative support services are directly charged to the applicable segment where practicable. In all other cases, administrative support services are allocated to the applicable segment based on services agreements. Intersegment revenues were not material to Alliant Energy's operations and there was no single customer whose revenues were 10% or more of Alliant Energy's consolidated revenues. All of Alliant Energy's operations and assets are located in the U.S.

Certain financial information relating to Alliant Energy's business segments, which represent the services provided to its customers, was as follows (in millions):

	Utility				ATC Investment, Non-utility,	Alliant Energy
2017	Electric	Gas	Other	Total	Parent and Other	Consolidated
Operating revenues	**$2,894.7**	**$400.9**	**$47.5**	**$3,343.1**	**$39.1**	**$3,382.2**
Depreciation and amortization	**412.0**	**38.2**	**7.7**	**457.9**	**3.9**	**461.8**
Operating income (loss)	**586.5**	**45.3**	**(11.7)**	**620.1**	**33.3**	**653.4**
Interest expense				**206.2**	**9.4**	**215.6**
Equity income from unconsolidated investments, net	**(0.7)**	**—**	**—**	**(0.7)**	**(44.1)**	**(44.8)**
Income taxes				**51.0**	**15.7**	**66.7**
Net income attributable to Alliant Energy common shareowners				**403.4**	**53.9**	**457.3**
Total assets	**11,396.2**	**1,199.8**	**766.5**	**13,362.5**	**825.3**	**14,187.8**
Investments in equity method subsidiaries	**8.3**	**—**	**—**	**8.3**	**373.1**	**381.4**
Construction and acquisition expenditures	**1,154.9**	**125.2**	**1.7**	**1,281.8**	**185.1**	**1,466.9**

	Utility				ATC Investment, Non-utility,	Alliant Energy
2016	Electric	Gas	Other	Total	Parent and Other	Consolidated
Operating revenues	$2,875.5	$355.4	$48.6	$3,279.5	$40.5	$3,320.0
Depreciation and amortization	367.0	34.2	2.1	403.3	8.3	411.6
Operating income (loss)	571.9	30.7	(4.8)	597.8	(60.8)	537.0
Interest expense				194.6	1.6	196.2
Equity income from unconsolidated investments, net	(0.7)	—	—	(0.7)	(38.9)	(39.6)
Income tax expense (benefit)				71.4	(12.0)	59.4
Net income (loss) attributable to Alliant Energy common shareowners				385.2	(13.7)	371.5
Total assets	10,722.9	1,091.1	781.0	12,595.0	778.8	13,373.8
Investments in equity method subsidiaries	7.7	—	—	7.7	318.3	326.0
Construction and acquisition expenditures	994.0	137.1	0.1	1,131.2	65.6	1,196.8

2015	Utility				ATC Investment, Non-utility, Parent and Other	Alliant Energy Consolidated
	Electric	Gas	Other	Total		
Operating revenues	$2,770.5	$381.2	$57.9	$3,209.6	$44.0	$3,253.6
Depreciation and amortization	358.6	31.1	1.8	391.5	9.8	401.3
Operating income	514.1	34.6	1.9	550.6	26.4	577.0
Interest expense				189.2	(2.1)	187.1
Equity income from unconsolidated investments, net	(0.9)	—	—	(0.9)	(32.9)	(33.8)
Income taxes				46.2	24.2	70.4
Net income attributable to Alliant Energy common shareowners				343.4	34.8	378.2
Total assets	9,918.0	939.3	828.9	11,686.2	809.0	12,495.2
Investments in equity method subsidiaries	8.7	—	—	8.7	294.2	302.9
Construction and acquisition expenditures	852.5	106.4	1.4	960.3	74.0	1,034.3

IPL - IPL is a utility primarily serving retail customers in Iowa and includes three reportable segments: a) electric operations; b) gas operations; and c) other, which includes steam operations and the unallocated portions of the utility business. Various line items in the following tables are not allocated to the electric and gas segments for management reporting purposes, and therefore, are included only in "Total." Intersegment revenues were not material to IPL's operations and there was no single customer whose revenues were 10% or more of IPL's consolidated revenues. All of IPL's operations and assets are located in the U.S. Certain financial information relating to IPL's business segments, which represent the services provided to its customers, was as follows (in millions):

2017	Electric	Gas	Other	Total
Operating revenues	**$1,598.9**	**$226.0**	**$45.4**	**$1,870.3**
Depreciation and amortization	**215.1**	**22.2**	**7.7**	**245.0**
Operating income (loss)	**281.1**	**20.8**	**(5.0)**	**296.9**
Interest expense				**112.4**
Income tax benefit				**(10.9)**
Earnings available for common stock				**216.8**
Total assets	**6,524.4**	**727.9**	**353.7**	**7,606.0**
Construction and acquisition expenditures	**594.1**	**80.7**	**1.2**	**676.0**

2016	Electric	Gas	Other	Total
Operating revenues	$1,569.7	$204.0	$46.7	$1,820.4
Depreciation and amortization	189.4	19.3	2.1	210.8
Operating income	252.0	15.5	3.3	270.8
Interest expense				103.2
Income tax benefit				(5.9)
Earnings available for common stock				215.6
Total assets	6,278.2	653.3	373.2	7,304.7
Construction and acquisition expenditures	598.1	91.5	0.1	689.7

2015	Electric	Gas	Other	Total
Operating revenues	$1,503.8	$217.3	$53.4	$1,774.5
Depreciation and amortization	187.9	17.5	1.8	207.2
Operating income	218.8	17.7	5.4	241.9
Interest expense				96.8
Income tax benefit				(22.7)
Earnings available for common stock				186.0
Total assets	5,754.1	548.2	406.8	6,709.1
Construction and acquisition expenditures	561.2	56.7	1.4	619.3

WPL - WPL is a utility serving customers in Wisconsin and includes three reportable segments: a) electric operations; b) gas operations; and c) other, which includes WPL's investment in ATC in 2015 and 2016, and the unallocated portions of the utility business. Refer to Note 6(a) for discussion of WPL's transfer of its investment in ATC to ATI as of December 31, 2016. Various line items in the following tables are not allocated to the electric and gas segments for management reporting purposes, and therefore, are included only in "Total." Intersegment revenues were not material to WPL's operations and there was no single customer whose revenues were 10% or more of WPL's consolidated revenues. All of WPL's operations and assets are located in the U.S. Certain financial information relating to WPL's business segments, which represent the services provided to its customers, was as follows (in millions):

2017	Electric	Gas	Other	Total
Operating revenues	**$1,295.8**	**$174.9**	**$2.1**	**$1,472.8**
Depreciation and amortization	**196.9**	**16.0**	**—**	**212.9**
Operating income (loss)	**305.4**	**24.5**	**(6.7)**	**323.2**
Interest expense				**93.8**
Equity income from unconsolidated investments	**(0.7)**	**—**	**—**	**(0.7)**
Income taxes				**61.9**
Earnings available for common stock				**186.6**
Total assets	**4,871.8**	**471.9**	**412.8**	**5,756.5**
Investments in equity method subsidiaries	**8.3**	**—**	**—**	**8.3**
Construction and acquisition expenditures	**592.4**	**44.5**	**0.5**	**637.4**

2016	Electric	Gas	Other	Total
Operating revenues	$1,305.8	$151.4	$1.9	$1,459.1
Depreciation and amortization	177.6	14.9	—	192.5
Operating income (loss)	319.9	15.2	(8.1)	327.0
Interest expense				91.4
Equity income from unconsolidated investments	(0.7)	—	(39.1)	(39.8)
Income taxes				93.3
Earnings available for common stock				190.4
Total assets	4,444.7	437.8	407.8	5,290.3
Investments in equity method subsidiaries	7.7	—	—	7.7
Construction and acquisition expenditures	395.9	45.6	11.5	453.0

2015	Electric	Gas	Other	Total
Operating revenues	$1,266.7	$163.9	$4.5	$1,435.1
Depreciation and amortization	170.7	13.6	—	184.3
Operating income (loss)	295.3	16.9	(3.5)	308.7
Interest expense				92.4
Equity income from unconsolidated investments	(0.9)	—	(34.2)	(35.1)
Income taxes				82.9
Earnings available for common stock				176.3
Total assets	4,163.9	391.1	715.4	5,270.4
Investments in equity method subsidiaries	8.7	—	293.3	302.0
Construction and acquisition expenditures	291.3	49.7	3.3	344.3

NOTE 18. RELATED PARTIES

Service Agreements - Pursuant to service agreements, IPL and WPL receive various administrative and general services from an affiliate, Corporate Services. These services are billed to IPL and WPL at cost based on expenses incurred by Corporate Services for the benefit of IPL and WPL, respectively. These costs consisted primarily of employee compensation and benefits, fees associated with various professional services, depreciation and amortization of property, plant and equipment, and a return on net assets. Corporate Services also acts as agent on behalf of IPL and WPL pursuant to the service agreements. As agent, Corporate Services enters into energy, capacity, ancillary services, and transmission sale and purchase transactions within MISO. Corporate Services assigns such sales and purchases among IPL and WPL based on statements received from MISO. The amounts billed for services provided, sales credited and purchases were as follows (in millions):

	IPL			WPL		
	2017	2016	2015	**2017**	2016	2015
Corporate Services billings	**$177**	$161	$150	**$135**	$133	$121
Sales credited	**23**	8	10	**13**	7	24
Purchases billed	**364**	433	366	**115**	102	66

As of December 31, net intercompany payables to Corporate Services were as follows (in millions):

	2017	2016
IPL	**$114**	$104
WPL	**61**	72

ATC - Pursuant to various agreements, WPL receives a range of transmission services from ATC. WPL provides operation, maintenance, and construction services to ATC. WPL and ATC also bill each other for use of shared facilities owned by each party. The related amounts billed between the parties were as follows (in millions):

	2017	2016	2015
ATC billings to WPL	**$105**	$110	$101
WPL billings to ATC	**10**	13	13

As of December 31, 2017 and 2016, WPL owed ATC net amounts of $9 million and $8 million, respectively.

Refer to Note 6(a) for discussion of WPL's transfer of its investment in ATC to ATI on December 31, 2016.

WPL's Sheboygan Falls Energy Facility Lease - Refer to Note 10(b) for discussion of WPL's Sheboygan Falls Energy Facility lease.

Franklin County Wind Farm - Refer to Note 3 for discussion of the transfer of the Franklin County wind farm from AEF to IPL in April 2017.

NOTE 19. SELECTED CONSOLIDATED QUARTERLY FINANCIAL DATA (UNAUDITED)

Alliant Energy - All "per share" references refer to earnings per diluted share. Summation of the individual quarters may not equal annual totals due to rounding.

	2017				2016			
	March 31	**June 30**	**Sep. 30**	**Dec. 31**	March 31	June 30	Sep. 30	Dec. 31
	(in millions, except per share data)							
Operating revenues	**$853.9**	**$765.3**	**$906.9**	**$856.1**	$843.8	$754.6	$924.6	$797.0
Operating income	**142.9**	**149.3**	**231.5**	**129.7**	145.9	128.6	162.6	99.9
Amounts attributable to Alliant Energy common shareowners:								
Income from continuing operations, net of tax	**99.0**	**94.3**	**168.8**	**93.8**	97.6	84.4	128.8	63.0
Income (loss) from discontinued operations, net of tax	**1.4**	**—**	**—**	**—**	(1.1)	(0.5)	(0.4)	(0.3)
Net income	**100.4**	**94.3**	**168.8**	**93.8**	96.5	83.9	128.4	62.7
Earnings per weighted average common share attributable to Alliant Energy common shareowners:								
Income from continuing operations, net of tax	**0.43**	**0.41**	**0.73**	**0.41**	0.43	0.37	0.57	0.28
Income from discontinued operations, net of tax	**0.01**	**—**	**—**	**—**	—	—	—	—
Net income	**0.44**	**0.41**	**0.73**	**0.41**	0.43	0.37	0.57	0.28

IPL - Earnings per share data is not disclosed for IPL given Alliant Energy is the sole shareowner of all shares of IPL's common stock outstanding during the periods presented.

	2017				2016			
	March 31	**June 30**	**Sep. 30**	**Dec. 31**	March 31	June 30	Sep. 30	Dec. 31
	(in millions)							
Operating revenues	**$450.5**	**$420.2**	**$527.4**	**$472.2**	$458.7	$411.0	$516.2	$434.5
Operating income	**49.6**	**66.3**	**131.8**	**49.2**	62.0	48.0	125.9	34.9
Net income	**39.8**	**45.3**	**123.0**	**18.9**	48.2	34.4	116.7	26.5
Earnings available for common stock	**37.2**	**42.8**	**120.4**	**16.4**	45.6	31.9	114.1	24.0

WPL - Earnings per share data is not disclosed for WPL given Alliant Energy is the sole shareowner of all shares of WPL's common stock outstanding during the periods presented.

	2017				2016			
	March 31	**June 30**	**Sep. 30**	**Dec. 31**	March 31	June 30	Sep. 30	Dec. 31
	(in millions)							
Operating revenues	**$393.1**	**$334.8**	**$370.2**	**$374.7**	$375.6	$334.3	$397.0	$352.2
Operating income	**86.0**	**73.7**	**90.7**	**72.8**	78.8	75.0	115.0	58.2
Net income	**45.5**	**38.1**	**49.8**	**53.2**	47.0	43.7	69.6	32.5
Earnings available for common stock	**45.5**	**38.1**	**49.8**	**53.2**	46.5	43.2	69.0	31.7

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Alliant Energy's, IPL's and WPL's management evaluated, with the participation of each of Alliant Energy's, IPL's and WPL's Chief Executive Officer, Chief Financial Officer and Disclosure Committee, the effectiveness of the design and operation of Alliant Energy's, IPL's and WPL's disclosure controls and procedures as of the end of the quarter ended December 31, 2017 pursuant to the requirements of the Securities Exchange Act of 1934, as amended. Based on their evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that Alliant Energy's, IPL's and WPL's disclosure controls and procedures were effective as of the end of the quarter ended December 31, 2017.

There was no change in Alliant Energy's, IPL's and WPL's internal control over financial reporting that occurred during the quarter ended December 31, 2017 that has materially affected, or is reasonably likely to materially affect, Alliant Energy's, IPL's and WPL's internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting - The management of Alliant Energy, IPL and WPL are responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Alliant Energy's, IPL's and WPL's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Because of the inherent limitations of internal control over financial reporting, misstatements may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Alliant Energy's, IPL's and WPL's management assessed the effectiveness of their respective internal control over financial reporting as of December 31, 2017 using the criteria set forth in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on these assessments, Alliant Energy's, IPL's and WPL's management concluded that, as of December 31, 2017, their respective internal control over financial reporting was effective.

Deloitte & Touche LLP, Alliant Energy's independent registered public accounting firm, has audited Alliant Energy's internal control over financial reporting. That report is included herein. This report does not include an attestation report of IPL's and WPL's independent registered public accounting firm regarding its assessment of IPL's and WPL's internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareowners of Alliant Energy Corporation

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Alliant Energy Corporation and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States (U.S.)) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2017, of the Company and our report dated February 23, 2018, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP
DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 23, 2018

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The directors of Alliant Energy, IPL and WPL are the same, and therefore, the information required by Item 10 relating to directors and nominees for election of directors is the same for all registrants. The information required by Item 10 relating to directors and nominees for election of directors at the 2018 Annual Meeting of Shareowners, the timely filing of reports under Section 16 of the Securities Exchange Act of 1934, audit committees and audit committee financial experts, and Alliant Energy's, IPL's and WPL's Code of Conduct is incorporated herein by reference to the relevant information in the 2018 Alliant Energy Proxy Statement, which will be filed with the SEC within 120 days after the end of Alliant Energy's, IPL's and WPL's fiscal years. The code of ethics, also referred to as the Code of Conduct, of Alliant Energy, IPL and WPL are the same. Information regarding executive officers of Alliant Energy, IPL and WPL may be found in Part I of this report under the caption "Executive Officers of the Registrants."

ITEM 11. EXECUTIVE COMPENSATION

The directors and executive officers of Alliant Energy, IPL and WPL for which compensation information must be included are the same. Therefore, the information required by Item 11 for each of Alliant Energy, IPL and WPL is incorporated herein by reference to the relevant information in the 2018 Alliant Energy Proxy Statement, which will be filed with the SEC within 120 days after the end of Alliant Energy's, IPL's and WPL's fiscal years.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

ALLIANT ENERGY

Information regarding Alliant Energy's equity compensation plans as of December 31, 2017 was as follows:

Plan Category	(A) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(B) Weighted-average exercise price of outstanding options, warrants and rights	(C) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (A))
Equity compensation plans approved by shareowners	769,881 (a)	$35.86	7,098,777 (b)
Equity compensation plans not approved by shareowners (c)	N/A	N/A	N/A (d)
	769,881	$35.86	7,098,777

(a) Represents performance shares, performance restricted stock units and restricted stock units granted under the OIP. Performance shares may be paid out in shares of Alliant Energy's common stock, cash, or a combination of cash and stock and performance restricted stock units are paid out in shares of Alliant Energy's common stock. The performance share and performance restricted stock unit awards are adjusted by a performance multiplier, which ranges from zero to 200%, based on the performance criteria. The performance share and performance restricted stock unit awards included in column (A) of the table reflect an assumed payout in the form of Alliant Energy's common stock at the maximum performance multiplier of 200% for the 2017 and 2016 grants and at the estimated payout percentage of 138% for the 2015 performance share grants. Also included are restricted stock units granted under the OIP, which may be paid out in shares of Alliant Energy's common stock, cash, or a combination of cash and stock at the expiration of a three-year time-vesting period.

(b) All of the available shares under the Amended and Restated OIP may be issued as awards in the form of shares of Alliant Energy's common stock, restricted stock, restricted stock units, performance shares, performance units and other stock-based or cash-based awards. As of December 31, 2017, there were performance shares, restricted stock awards, performance restricted stock units and restricted stock units outstanding under the Amended and Restated OIP. Excludes 90,806 shares of nonvested performance-contingent restricted stock previously issued and outstanding under the Amended and Restated OIP at December 31, 2017.

(c) As of December 31, 2017, there were 463,365 shares of Alliant Energy's common stock held under the DCP, which is described in Note 12(c).

(d) There is no limit on the number of shares of Alliant Energy's common stock that may be held under the DCP.

The remainder of the information required by Item 12 is incorporated herein by reference to the relevant information in the 2018 Alliant Energy Proxy Statement, which will be filed with the SEC within 120 days after the end of Alliant Energy's fiscal year.

IPL AND WPL

None of IPL's directors or executive officers own any shares of preferred stock in IPL. The remainder of the information required by Item 12 is incorporated herein by reference to the relevant information in the 2018 Alliant Energy Proxy Statement, which will be filed with the SEC within 120 days after the end of IPL's and WPL's fiscal years.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by Item 13 for each of Alliant Energy, IPL and WPL is incorporated herein by reference to the relevant information in the 2018 Alliant Energy Proxy Statement, which will be filed with the SEC within 120 days after the end of Alliant Energy's, IPL's and WPL's fiscal years.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

ALLIANT ENERGY

The information required by Item 14 is incorporated herein by reference to the relevant information in the 2018 Alliant Energy Proxy Statement, which will be filed with the SEC within 120 days after the end of Alliant Energy's fiscal year.

IPL AND WPL

Each of IPL's and WPL's Audit Committee of the Board of Directors has adopted a policy that requires advance approval of all audit, audit-related, tax and other permitted services performed by the independent registered public accounting firm. The policy provides for pre-approval by the Audit Committee of specifically defined audit and non-audit services after the Audit Committee is provided with the appropriate level of details regarding the specific services to be provided. The policy does not permit delegation of the Audit Committee's authority to management. In the event the need for specific services arises between Audit Committee meetings, the Audit Committee has delegated to the Chairperson of the Audit Committee authority to approve permitted services provided that the Chairperson reports any decisions to the Audit Committee at its next scheduled meeting. The principal accounting fees billed to Alliant Energy by its independent registered public accounting firm, all of which were approved in advance by the Audit Committee, directly related and allocated to IPL and WPL were as follows (in thousands):

	IPL				WPL			
	2017		2016		**2017**		2016	
	Fees	**% of Total**	Fees	% of Total	**Fees**	**% of Total**	Fees	% of Total
Audit fees	**$1,083**	**90%**	$1,035	93%	**$1,070**	**93%**	$1,008	95%
Audit-related fees	**67**	**5%**	64	6%	**42**	**4%**	41	4%
Tax fees	**9**	**1%**	—	—%	**2**	**—%**	—	—%
All other fees	**44**	**4%**	8	1%	**36**	**3%**	7	1%
	$1,203	**100%**	$1,107	100%	**$1,150**	**100%**	$1,056	100%

IPL's and WPL's audit fees for 2017 and 2016 consisted of the respective fees billed for the audits of the financial statements of IPL and its subsidiary and WPL and its subsidiary, for reviews of financial statements included in Form 10-Q filings, and for services normally provided in connection with statutory and regulatory filings, such as financing transactions. IPL's and WPL's audit fees also included their respective portion of fees for the 2017 and 2016 audits of Alliant Energy's financial statements and effectiveness of internal controls over financial reporting. IPL's and WPL's audit-related fees for 2017 and 2016 consisted of the fees billed for services rendered related to employee benefits plan audits and other attest services. IPL's and WPL's tax fees for 2017 consisted of the fees billed for professional services rendered for tax compliance, tax advice and tax planning, including all services performed by the tax professional staff of affiliates of the independent registered public accounting firm, except those rendered in connection with the audit. IPL and WPL did not have any tax fees for 2016. All other fees for 2017 and 2016 for IPL and WPL consisted of license fees for accounting research software products and seminars, and, with respect to 2017, consultation services. The Audit Committee does not consider the provision of non-audit services by the independent registered public accounting firm described above to be incompatible with maintaining independence of the independent registered public accounting firm.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(1) Consolidated Financial Statements - Refer to Item 8 Financial Statements and Supplementary Data.

(2) Financial Statement Schedules -

SCHEDULE I - CONDENSED PARENT COMPANY FINANCIAL STATEMENTS

ALLIANT ENERGY CORPORATION (Parent Company Only)
CONDENSED STATEMENTS OF INCOME

	Year Ended December 31,		
	2017	2016	2015
		(in millions)	
Operating revenues	**$—**	$1	$2
Operating expenses	**2**	3	3
Operating loss	**(2)**	(2)	(1)
Interest expense and other:			
Equity earnings from consolidated subsidiaries	**(457)**	(374)	(379)
Interest expense	**3**	3	3
Interest income	**—**	(2)	(3)
Total interest expense and other	**(454)**	(373)	(379)
Income before income taxes	**452**	371	378
Income tax benefit	**(6)**	(1)	(1)
Net income	**$458**	$372	$379

The accompanying Notes to Condensed Financial Statements are an integral part of these statements.

ALLIANT ENERGY CORPORATION (Parent Company Only)
CONDENSED BALANCE SHEETS

	December 31,	
	2017	2016
	(in millions)	
ASSETS		
Current assets:		
Notes receivable from affiliated companies	**$50**	$74
Other	**7**	5
Total current assets	**57**	79
Investments:		
Investments in consolidated subsidiaries	**4,676**	4,211
Other	**2**	2
Total investments	**4,678**	4,213
Other assets	**78**	64
Total assets	**$4,813**	$4,356
LIABILITIES AND EQUITY		
Current liabilities:		
Commercial paper	**$295**	$192
Notes payable to affiliated companies	**305**	275
Other	**12**	12
Total current liabilities	**612**	479
Other liabilities	**20**	18
Common equity:		
Common stock and additional paid-in capital	**1,848**	1,695
Retained earnings	**2,344**	2,174
Shares in deferred compensation trust	**(11)**	(10)
Total common equity	**4,181**	3,859
Total liabilities and equity	**$4,813**	$4,356

The accompanying Notes to Condensed Financial Statements are an integral part of these statements.

ALLIANT ENERGY CORPORATION (Parent Company Only)
CONDENSED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017	2016	2015
		(in millions)	
Net cash flows from operating activities	**$273**	$254	$262
Cash flows from (used for) investing activities:			
Capital contributions to consolidated subsidiaries	**(290)**	(250)	(165)
Capital repayments from consolidated subsidiaries	**—**	130	—
Net change in notes receivable from and payable to affiliates	**54**	294	2
Other	**—**	10	—
Net cash flows from (used for) investing activities	**(236)**	184	(163)
Cash flows used for financing activities:			
Common stock dividends	**(288)**	(267)	(247)
Proceeds from issuance of common stock, net	**150**	27	151
Payments to retire long-term debt	**—**	(250)	—
Net change in commercial paper	**103**	52	(1)
Other	**(2)**	—	(2)
Net cash flows used for financing activities	**(37)**	(438)	(99)
Net increase (decrease) in cash and cash equivalents	**—**	—	—
Cash and cash equivalents at beginning of period	**—**	—	—
Cash and cash equivalents at end of period	**$—**	$—	$—
Supplemental cash flows information:			
Cash paid during the period for:			
Interest, net of capitalized interest	**($3)**	($3)	($3)
Income taxes, net	**—**	(37)	(9)

The accompanying Notes to Condensed Financial Statements are an integral part of these statements.

ALLIANT ENERGY CORPORATION
(Parent Company Only)
NOTES TO CONDENSED FINANCIAL STATEMENTS

Pursuant to rules and regulations of the SEC, the Condensed Financial Statements of Alliant Energy Corporation (Parent Company Only) do not reflect all of the information and notes normally included with financial statements prepared in accordance with GAAP. Therefore, these Condensed Financial Statements should be read in conjunction with the Financial Statements and related Notes included in the combined 2017 Form 10-K, Part II, Item 8, which is incorporated herein by reference.

In the Condensed Financial Statements of Alliant Energy Corporation (Parent Company Only), investments in subsidiaries are accounted for using the equity method.

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Description	Balance, January 1	Additions: Charged to Expense	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance, December 31
			(in millions)		
Valuation and Qualifying Accounts Which are Deducted in the Balance Sheet From the Assets to Which They Apply:					
Accumulated Provision for Uncollectible Accounts:					
Alliant Energy (c)					
Year ended December 31, 2017	$8.7	$15.1	$5.4	$17.2	$12.0
Year ended December 31, 2016	4.8	17.4	8.8	22.3	8.7
Year ended December 31, 2015	5.1	8.1	3.0	11.4	4.8
IPL (c)					
Year ended December 31, 2017	$1.1	$14.9	$—	$14.7	$1.3
Year ended December 31, 2016	0.6	17.2	—	16.7	1.1
Year ended December 31, 2015	0.4	8.1	—	7.9	0.6
WPL					
Year ended December 31, 2017	$7.1	$0.2	$5.4	$2.0	$10.7
Year ended December 31, 2016	3.7	0.1	8.8	5.5	7.1
Year ended December 31, 2015	4.2	—	3.0	3.5	3.7
Note: The above provisions relate to various customer, notes and other receivable balances included in various line items on the respective balance sheets.					
Other Reserves:					
Accumulated Provision for Other Reserves (d):					
Alliant Energy					
Year ended December 31, 2017	$25.1	$3.3	$5.1	$10.5	$23.0
Year ended December 31, 2016	27.1	6.1	—	8.1	25.1
Year ended December 31, 2015	32.6	6.5	—	12.0	27.1
IPL					
Year ended December 31, 2017	$8.7	$0.3	$—	$1.4	$7.6
Year ended December 31, 2016	9.4	1.0	—	1.7	8.7
Year ended December 31, 2015	10.6	2.1	—	3.3	9.4
WPL					
Year ended December 31, 2017	$8.1	$0.1	$—	$1.8	$6.4
Year ended December 31, 2016	11.4	1.8	—	5.1	8.1
Year ended December 31, 2015	16.3	0.7	—	5.6	11.4

(a) Accumulated provision for uncollectible accounts: In accordance with its regulatory treatment, certain amounts provided by WPL are recorded in regulatory assets. WPL expenses these amounts when an uncollectible account is written-off.
Accumulated provision for other reserves: In 2017, Alliant Energy recorded amounts to deferred tax liabilities related to the impacts of Tax Reform, which is discussed in Note 11.

(b) Deductions are of the nature for which the reserves were created. In the case of the accumulated provision for uncollectible accounts, deductions from this reserve are reduced by recoveries of amounts previously written off.

(c) Refer to Note 5(b) for discussion of IPL's sales of accounts receivable program.

(d) Other reserves are largely related to injury and damage claims arising in the ordinary course of business, and the impacts of Tax Reform.

NOTE: All other schedules are omitted because they are not applicable or not required, or because that required information is shown either in the financial statements or in the notes thereto.

(3) Exhibits Required by SEC Regulation S-K - Pursuant to Item 601(b)(4)(iii) of Regulation S-K, the registrants agree to furnish to the SEC, upon request, any instrument defining the rights of holders of unregistered long-term debt not filed as an exhibit to this combined Form 10-K. No such instrument authorizes securities in excess of 10% of the total assets of Alliant Energy, IPL or WPL, as the case may be. The following exhibits for Alliant Energy, IPL and WPL are filed herewith or incorporated herein by reference.

Exhibit Number	Description
1.1	Distribution Agreement dated May 9, 2017, among Alliant Energy; Wells Fargo Securities, LLC; Barclays Capital Inc.; and MUFG Securities Americas Inc. (incorporated by reference to Exhibit 1.1 to Alliant Energy's Form 8-K, filed May 9, 2017 (File No. 1-9894))
3.1	Restated Articles of Incorporation of Alliant Energy, as amended (incorporated by reference to Exhibit 4.1 to Alliant Energy's Registration Statement on Form S-8 (Reg. No. 333-117654))
3.1a	Articles of Amendment to Restated Articles of Incorporation of Alliant Energy, as amended, effective May 4, 2016 (incorporated by reference to Exhibit 3.1 to Alliant Energy's Form 10-Q for the quarter ended March 31, 2016 (File No. 1-9894))
3.2	Amended and Restated Bylaws of Alliant Energy, effective May 7, 2015 (incorporated by reference to Exhibit 3.1 to Alliant Energy's Form 8-K, filed May 13, 2015 (File No. 1-9894))
3.3	Amended and Restated Articles of Incorporation of WPL, effective May 9, 2013 (incorporated by reference to Exhibit 3.4 to WPL's Form 8-K, filed May 13, 2013 (File No. 0-337))
3.4	Amended and Restated Bylaws of WPL, effective May 7, 2015 (incorporated by reference to Exhibit 3.3 to WPL's Form 8-K, filed May 13, 2015 (File No. 0-337))
3.5	Amended and Restated Articles of Incorporation of IPL, effective May 10, 2013 (incorporated by reference to Exhibit 3.2 to IPL's Form 8-K, filed May 13, 2013 (File No. 1-4117))
3.6	Amended and Restated Bylaws of IPL, effective May 7, 2015 (incorporated by reference to Exhibit 3.2 to IPL's Form 8-K, filed May 13, 2015 (File No. 1-4117))
4.1	Five-Year Master Credit Agreement, dated as of August 16, 2017, among Alliant Energy, IPL, WPL, Wells Fargo Bank, National Association and the lender parties set forth therein (incorporated by reference to Exhibit 4.1 to Alliant Energy's Form 8-K, filed August 21, 2017 (File No. 1-9894))
4.2	Senior Note Indenture, dated as of September 30, 2009, between Alliant Energy and Wells Fargo Bank, National Association (N.A.) (incorporated by reference to Exhibit 4.28 to Alliant Energy's Registration Statement on Form S-3 (Reg. No. 333-162214))
4.3	Indenture, dated as of June 20, 1997, between WPL and Wells Fargo Bank, N.A., Successor, as Trustee (incorporated by reference to Exhibit 4.33 to Amendment No. 2 to WPL's Registration Statement on Form S-3 (Reg. No. 033-60917))
4.4	Officers' Certificate, dated as of July 28, 2004, creating WPL's 6.25% Debentures due July 31, 2034 (incorporated by reference to Exhibit 4.1 to WPL's Form 8-K, filed August 2, 2004 (File No. 0-337))
4.5	Officers' Certificate, dated as of August 8, 2007, creating WPL's 6.375% Debentures due August 15, 2037 (incorporated by reference to Exhibit 4.1 to WPL's Form 8-K, filed August 9, 2007 (File No. 0-337))
4.6	Officer's Certificate, dated as of October 1, 2008, creating WPL's 7.60% Debentures due October 1, 2038 (incorporated by reference to Exhibit 4.2 to WPL's Form 8-K, filed October 2, 2008 (File No. 0-337))
4.7	Officers' Certificate, dated as of July 7, 2009, creating WPL's 5.00% Debentures due July 15, 2019 (incorporated by reference to Exhibit 4.2 to WPL's Form 8-K, filed July 8, 2009 (File No. 0-337))
4.8	Officers' Certificate, dated as of June 10, 2010, creating WPL's 4.60% Debentures due June 15, 2020 (incorporated by reference to Exhibit 4.2 to WPL's Form 8-K, filed June 11, 2010 (File No. 0-337))
4.9	Officers' Certificate, dated as of November 19, 2012, creating WPL's 2.25% Debentures due November 15, 2022 (incorporated by reference to Exhibit 4.1 to WPL's Form 8-K, filed November 19, 2012 (File No. 0-337))
4.10	Officers' Certificate, dated as of October 14, 2014, creating WPL's 4.10% Debentures due October 15, 2044 (incorporated by reference to Exhibit 4.1 to WPL's Form 8-K, filed October 14, 2014 (File No. 0-337))
4.11	Officers' Certificate, dated as of October 10, 2017, creating WPL's 3.05% Debentures due October 15, 2027 (incorporated by reference to Exhibit 4.1 to WPL's Form 8-K, filed October 10, 2017 (File No. 0-337))
4.12	Indenture (For Senior Unsecured Debt Securities), dated as of August 20, 2003, between IPL and The Bank of New York Mellon Trust Co., N.A. (f/k/a The Bank of New York Trust Co., N.A.), as Trustee (incorporated by reference to Exhibit 4.11 to IPL's Registration Statement on Form S-3 (Reg. No. 333-108199))
4.13	Officer's Certificate, dated as of September 10, 2003, creating IPL's 5.875% Senior Debentures due September 15, 2018 (incorporated by reference to Exhibit 4.1 to IPL's Form 8-K, filed September 11, 2003 (File No. 1-4117))
4.14	Officer's Certificate, dated as of October 14, 2003, creating IPL's 6.45% Senior Debentures due October 15, 2033 (incorporated by reference to Exhibit 4.1 to IPL's Form 8-K, filed October 15, 2003 (File No. 1-4117))
4.15	Officer's Certificate, dated as of May 3, 2004, creating IPL's 6.30% Senior Debentures due May 1, 2034 (incorporated by reference to Exhibit 4.1 to IPL's Form 8-K, filed May 5, 2004 (File No. 1-4117))
4.15a	Officer's Certificate, dated as of August 2, 2004, reopening IPL's 6.30% Senior Debentures due May 1, 2034 (incorporated by reference to Exhibit 4.1 to IPL's Form 8-K, filed August 5, 2004 (File No. 1-4117))
4.16	Officer's Certificate, dated as of July 18, 2005, creating IPL's 5.50% Senior Debentures due July 15, 2025 (incorporated by reference to Exhibit 4 to IPL's Form 8-K, filed July 19, 2005 (File No. 1-4117))

Exhibit Number	Description
4.17	Officer's Certificate, dated as of October 1, 2008, creating IPL's 7.25% Senior Debentures due October 1, 2018 (incorporated by reference to Exhibit 4.1 to IPL's Form 8-K, filed October 2, 2008 (File No. 1-4117))
4.18	Officer's Certificate, dated as of July 7, 2009, creating IPL's 6.25% Senior Debentures due July 15, 2039 (incorporated by reference to Exhibit 4.1 to IPL's Form 8-K, filed July 8, 2009 (File No. 1-4117))
4.19	Officer's Certificate, dated as of August 23, 2010, creating IPL's 3.65% Senior Debentures due September 1, 2020 (incorporated by reference to Exhibit 4.1 to IPL's Form 8-K, filed August 24, 2010 (File No. 1-4117))
4.20	Officer's Certificate, dated as of October 8, 2013, creating IPL's 4.70% Senior Debentures due October 15, 2043 (incorporated by reference to Exhibit 4.1 to IPL's Form 8-K, filed October 8, 2013 (File No. 1-4117))
4.21	Officer's Certificate, dated as of November 24, 2014, creating IPL's 3.25% Senior Debentures due December 1, 2024 (incorporated by reference to Exhibit 4.1 to IPL's Form 8-K, filed November 24, 2014 (File No. 1-4117))
4.21a	Officer's Certificate, dated as of November 15, 2017, reopening IPL's 3.25% Senior Debentures due December 1, 2024 (incorporated by reference to Exhibit 4.1 to IPL's Form 8-K, filed November 15, 2017 (File No. 1-4117))
4.22	Officer's Certificate, dated as of August 18, 2015, creating IPL's 3.40% Senior Debentures due August 15, 2025 (incorporated by reference to Exhibit 4.1 to IPL's Form 8-K, filed August 18, 2015 (File No. 1-4117))
4.23	Officer's Certificate, dated as of September 15, 2016, creating IPL's 3.70% Senior Debentures due September 15, 2046 (incorporated by reference to Exhibit 4.1 to IPL's Form 8-K, filed September 15, 2016 (File No. 1-4117))
4.24	Form of Preferred Stock Certificate of IPL (incorporated by reference to Exhibit 4.1 to IPL's Form 8-K, filed March 20, 2013 (File No. 1-4117))
10.1	Term Loan Credit Agreement, dated as of October 7, 2016, among AEF, Alliant Energy, JPMorgan Chase Bank, N.A. and the lender parties set forth therein (incorporated by reference to Exhibit 10.1 to Alliant Energy's Form 8-K, filed October 7, 2016 (File No. 1-9894))
10.2#	OIP (incorporated by reference to Appendix A to Alliant Energy's definitive proxy statement filed on Schedule 14A on April 1, 2010 (File No. 1-9894))
10.2a#	Amendment to the OIP (incorporated by reference to Exhibit 10.1 to Alliant Energy's Form 8-K, filed December 5, 2011 (File No. 1-9894))
10.2b#	Form of Performance Share Agreement amended in 2015, pursuant to the OIP, amended in 2012 (incorporated by reference to Exhibit 10.3c to Alliant Energy's Form 10-K for the year 2014 (File No. 1-9894))
10.2c#	Form of Performance Contingent Restricted Stock Agreement amended in 2015, pursuant to the OIP, amended in 2012 (incorporated by reference to Exhibit 10.3e to Alliant Energy's Form 10-K for the year 2014 (File No. 1-9894))
10.3#	Amended and Restated OIP, amended in 2015 (incorporated by reference to Appendix A to Alliant Energy's definitive proxy statement filed on Schedule 14A on March 24, 2015 (File No. 1-9894))
10.3a#	Form of Performance Share Agreement pursuant to the Amended and Restated OIP, amended in 2015 (incorporated by reference to Exhibit 10.4a to Alliant Energy's Form 10-K for the year 2015 (File No. 1-9894))
10.3b#	Form of Restricted Stock Unit Agreement pursuant to the Amended and Restated OIP, amended in 2015 (incorporated by reference to Exhibit 10.4b to Alliant Energy's Form 10-K for the year 2015 (File No. 1-9894))
10.3c#	Form of Performance Restricted Stock Unit Agreement pursuant to the Amended and Restated OIP, amended in 2015 (incorporated by reference to Exhibit 10.4c to Alliant Energy's Form 10-K for the year 2015 (File No. 1-9894))
10.4#	DLIP, for director-level employees, amended in 2012 (incorporated by reference to Exhibit 10.5c to Alliant Energy's Form 10-K for the year 2011 (File No. 1-9894))
10.4a#	Form of Restricted Cash Agreement pursuant to the DLIP, amended in 2012 (incorporated by reference to Exhibit 10.5d to Alliant Energy's Form 10-K for the year 2011 (File No. 1-9894))
10.4b#	Form of Performance Restricted Award Agreement pursuant to the DLIP, amended in 2012 (incorporated by reference to Exhibit 10.5e to Alliant Energy's Form 10-K for the year 2011 (File No. 1-9894))
10.5#	DLIP, for director-level employees, amended in 2016 (incorporated by reference to Exhibit 10.6 to Alliant Energy's Form 10-K for the year 2016 (File No. 1-9894))
10.5a#	Form of Performance Unit Agreement pursuant to the DLIP, amended in 2016 (incorporated by reference to Exhibit 10.6a to Alliant Energy's Form 10-K for the year 2016 (File No. 1-9894))
10.5b#	Form of Performance Restricted Unit Agreement pursuant to the DLIP, amended in 2016 (incorporated by reference to Exhibit 10.6b to Alliant Energy's Form 10-K for the year 2016 (File No. 1-9894))
10.5c#	Form of Restricted Unit Agreement pursuant to the DLIP, amended in 2016 (incorporated by reference to Exhibit 10.6c to Alliant Energy's Form 10-K for the year 2016 (File No. 1-9894))
10.6#	DCP, as amended and restated effective January 1, 2011 (incorporated by reference to Exhibit 10.1 to Alliant Energy's Form 8-K, filed December 14, 2010 (File No. 1-9894))

Exhibit Number	Description
10.6a#	Amendment to the DCP, as amended and restated (incorporated by reference to Exhibit 10.2 to Alliant Energy's Form 8-K, filed December 5, 2011 (File No. 1-9894))
10.7#	IES Industries Inc. Amended and Restated Key Employee Deferred Compensation Agreement, as amended (incorporated by reference to Exhibit 10.7 to Alliant Energy's Form 10-K for the year 2015 (File No. 1-9894))
10.8#	Alliant Energy Rabbi Trust Agreement for DCPs (incorporated by reference to Exhibit 10.19 to Alliant Energy's Form 10-K for the year 2005 (File No. 1-9894))
10.8a#	Amendment to the Alliant Energy Rabbi Trust Agreement for DCPs (incorporated by reference to Exhibit 10.2 to Alliant Energy's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-9894))
10.8b#	Second Amendment to the Alliant Energy Rabbi Trust Agreement for DCPs (incorporated by reference to Exhibit 10.3 to Alliant Energy's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-9894))
10.9#	Alliant Energy Excess Retirement Plan (incorporated by reference to Exhibit 10.1 to Alliant Energy's Form 10-Q for the quarter ended September 30, 2008 (File No. 1-9894))
10.9a#	Amendment to the Alliant Energy Excess Retirement Plan (incorporated by reference to Exhibit 10.4 to Alliant Energy's Form 8-K, filed December 5, 2011 (File No. 1-9894))
10.10#	Form of Supplemental Retirement Plan (SRP) Agreement by and between Alliant Energy and each of P.L. Kampling and J.O. Larsen (incorporated by reference to Exhibit 10.3 to Alliant Energy's Form 8-K, filed December 12, 2008 (File No. 1-9894))
10.11#	Alliant Energy Defined Contribution SRP (incorporated by reference to Exhibit 10.1 to Alliant Energy's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-9894))
10.11a#	Amendment to the Alliant Energy Defined Contribution SRP (incorporated by reference to Exhibit 10.3 to Alliant Energy's Form 8-K, filed December 5, 2011 (File No. 1-9894))
10.11b#	Amendment to the Alliant Energy Defined Contribution SRP (incorporated by reference to Exhibit 10.1 to Alliant Energy's Form 8-K, filed March 12, 2014 (File No. 1-9894))
10.12#	Form of Key Executive Employment and Severance Agreement (KEESA), by and between Alliant Energy and P.L. Kampling (incorporated by reference to Exhibit 10.1 to Alliant Energy's Form 8-K, filed October 29, 2010 (File No. 1-9894))
10.13#	Form of KEESA, by and between Alliant Energy and each of J.H. Gallegos, D.R. Kopp, J.O. Larsen, W.A. Reschke and R.J. Durian (incorporated by reference to Exhibit 10.3 to Alliant Energy's Form 10-Q for the quarter ended June 30, 2008 (File No. 1-9894))
10.13a#	Form of Amendment to KEESA, by and between Alliant Energy and each of J.H. Gallegos, D.R. Kopp, J.O. Larsen, W.A. Reschke and R.J. Durian (incorporated by reference to Exhibit 10.1 to Alliant Energy's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-9894))
10.14#	Form of Amendment Number One to KEESA, by and between Alliant Energy and each of P.L. Kampling, J.H. Gallegos, D.R. Kopp, J.O. Larsen, W.A. Reschke and R.J. Durian (incorporated by reference to Exhibit 10.6 to Alliant Energy's Form 8-K, filed December 5, 2011 (File No. 1-9894))
10.15#	Executive Severance Benefit under the Alliant Energy Severance Plan Summary Plan Description, effective March 19, 2008 (incorporated by reference to Exhibit 10.1 to Alliant Energy's Form 8-K, filed March 24, 2008 (File No. 1-9894))
10.15a#	Amendment to the Executive Severance Benefit under the Alliant Energy Severance Plan Summary Plan Description (incorporated by reference to Exhibit 10.5 to Alliant Energy's Form 8-K, filed December 5, 2011 (File No. 1-9894))
10.16#	Terms of Alliant Energy Executive Performance Pay Plan (incorporated by reference to Exhibit 10.18 to Alliant Energy's Form 10-K for the year 2015 (File No. 1-9894))
10.17#	Summary of Compensation and Benefits for Non-Employee Directors of Alliant Energy, IPL and WPL, effective January 1, 2018
12.1	Ratio of Earnings to Fixed Charges for Alliant Energy
12.2	Ratio of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements for IPL
12.3	Ratio of Earnings to Fixed Charges for WPL
21.1	Subsidiaries of Alliant Energy
23.1	Consent of Independent Registered Public Accounting Firm for Alliant Energy
23.2	Consent of Independent Registered Public Accounting Firm for IPL
23.3	Consent of Independent Registered Public Accounting Firm for WPL
31.1	Certification of the Chairman and Chief Executive Officer for Alliant Energy
31.2	Certification of the Senior Vice President, Chief Financial Officer and Treasurer for Alliant Energy
31.3	Certification of the Chairman and Chief Executive Officer for IPL
31.4	Certification of the Senior Vice President, Chief Financial Officer and Treasurer for IPL
31.5	Certification of the Chairman and Chief Executive Officer for WPL
31.6	Certification of the Senior Vice President, Chief Financial Officer and Treasurer for WPL
32.1	Written Statement of the Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C.§1350 for Alliant Energy

Exhibit Number	Description
32.2	Written Statement of the Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C.§1350 for IPL
32.3	Written Statement of the Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C.§1350 for WPL
101.INS	Extensible Business Reporting Language (XBRL) Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

A management contract or compensatory plan or arrangement.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrants have duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized on the 23rd day of February 2018.

ALLIANT ENERGY CORPORATION	INTERSTATE POWER AND LIGHT COMPANY	WISCONSIN POWER AND LIGHT COMPANY
By: /s/ Patricia L. Kampling	By: /s/ Patricia L. Kampling	By: /s/ Patricia L. Kampling
Patricia L. Kampling	Patricia L. Kampling	Patricia L. Kampling
Chairman and Chief Executive Officer	Chairman and Chief Executive Officer	Chairman and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrants and in the capacities indicated on the 23rd day of February 2018.

ALLIANT ENERGY CORPORATION	INTERSTATE POWER AND LIGHT COMPANY	WISCONSIN POWER AND LIGHT COMPANY
By: /s/ Patricia L. Kampling	By: /s/ Patricia L. Kampling	By: /s/ Patricia L. Kampling
Patricia L. Kampling	Patricia L. Kampling	Patricia L. Kampling
Chairman, Chief Executive Officer and Director (Principal Executive Officer)	Chairman, Chief Executive Officer and Director (Principal Executive Officer)	Chairman, Chief Executive Officer and Director (Principal Executive Officer)
/s/ Robert J. Durian	/s/ Robert J. Durian	/s/ Robert J. Durian
Robert J. Durian	Robert J. Durian	Robert J. Durian
Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Benjamin M. Bilitz	/s/ Benjamin M. Bilitz	/s/ Benjamin M. Bilitz
Benjamin M. Bilitz	Benjamin M. Bilitz	Benjamin M. Bilitz
Chief Accounting Officer and Controller (Principal Accounting Officer)	Chief Accounting Officer and Controller (Principal Accounting Officer)	Chief Accounting Officer and Controller (Principal Accounting Officer)
/s/ Patrick E. Allen	/s/ Patrick E. Allen	/s/ Patrick E. Allen
Patrick E. Allen, Director	Patrick E. Allen, Director	Patrick E. Allen, Director
/s/ Michael L. Bennett	/s/ Michael L. Bennett	/s/ Michael L. Bennett
Michael L. Bennett, Director	Michael L. Bennett, Director	Michael L. Bennett, Director
/s/ Deborah B. Dunie	/s/ Deborah B. Dunie	/s/ Deborah B. Dunie
Deborah B. Dunie, Director	Deborah B. Dunie, Director	Deborah B. Dunie, Director
/s/ Darryl B. Hazel	/s/ Darryl B. Hazel	/s/ Darryl B. Hazel
Darryl B. Hazel, Director	Darryl B. Hazel, Director	Darryl B. Hazel, Director
/s/ Singleton B. McAllister	/s/ Singleton B. McAllister	/s/ Singleton B. McAllister
Singleton B. McAllister, Director	Singleton B. McAllister, Director	Singleton B. McAllister, Director
/s/ Thomas F. O'Toole	/s/ Thomas F. O'Toole	/s/ Thomas F. O'Toole
Thomas F. O'Toole, Director	Thomas F. O'Toole, Director	Thomas F. O'Toole, Director
/s/ Dean C. Oestreich	/s/ Dean C. Oestreich	/s/ Dean C. Oestreich
Dean C. Oestreich, Director	Dean C. Oestreich, Director	Dean C. Oestreich, Director
/s/ Carol P. Sanders	/s/ Carol P. Sanders	/s/ Carol P. Sanders
Carol P. Sanders, Director	Carol P. Sanders, Director	Carol P. Sanders, Director
/s/ Susan D. Whiting	/s/ Susan D. Whiting	/s/ Susan D. Whiting
Susan D. Whiting, Director	Susan D. Whiting, Director	Susan D. Whiting, Director

Exhibit 10.17

ALLIANT ENERGY CORPORATION
INTERSTATE POWER AND LIGHT COMPANY
WISCONSIN POWER AND LIGHT COMPANY

Summary of Compensation and Benefits for
Non-Employee Directors
Effective January 1, 2018

Effective January 1, 2018, the aggregate compensation for non-employee members of the Board of Directors (the "Board") of Alliant Energy Corporation, Interstate Power and Light Company and Wisconsin Power and Light Company will be as follows:

Non-employee members of the Board will be entitled to receive the following annual retainers as applicable:

- $225,000 for each non-employee director;
- $25,000 for the Lead Independent Director of the Board;
- $20,000 for the Chairperson of the Audit Committee of the Board;
- $5,000 for each member of the Audit Committee of the Board other than the Chairperson;
- $15,000 for the Chairperson of the Compensation and Personnel Committee of the Board; and
- $12,500 for the Chairperson of each of the Nominating and Governance Committee, and the Safety, Environmental, Policy and Operations Committee of the Board.

Payments of all retainers shall be in cash and shall be paid quarterly in advance.

Each director may, and is encouraged to, voluntarily elect an amount of any of the cash compensation retainers to purchase common stock of Alliant Energy Corporation under the Shareowner Direct Plan or to have an amount be deferred in the Alliant Energy Deferred Compensation Plan Stock Account.

Alliant Energy Corporation maintains a Director's Charitable Award Program for directors who were elected or appointed to the Board on or prior to January 1, 2005. Under the Program, when a director dies, Alliant Energy Corporation will donate a total of $500,000 to one qualified charitable organization or divide that amount among a maximum of five qualified charitable organizations selected by the individual director. All deductions for charitable contributions are taken by Alliant Energy Corporation, and the donations are funded by Alliant Energy Corporation through life insurance policies on the directors.

Directors are eligible to participate in the Alliant Energy Foundation, Inc. (the "Foundation") matching gift program, which is generally available to all employees and retirees. Under this program, the Foundation matches 100% of charitable donations over $50 to eligible charities up to a maximum of $2,500 per year for each director.

Directors are reimbursed for travel and other necessary expenses incurred in the performance of their responsibilities as members of the Board of Directors.

Exhibit 12.1

ALLIANT ENERGY CORPORATION

RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(dollars in millions)				
EARNINGS:					
Net income from continuing operations attributable to Alliant Energy Corporation common shareowners	$455.9	$373.8	$380.7	$385.5	$364.2
Income taxes (a)	66.7	59.4	70.4	44.3	53.9
Subtotal	522.6	433.2	451.1	429.8	418.1
Fixed charges as defined	229.8	210.2	202.3	195.7	189.0
Adjustment for undistributed equity earnings	(6.7)	(11.3)	(3.2)	(4.0)	(8.3)
Less:					
Interest capitalized	0.5	0.2	1.3	1.0	0.5
Preferred dividend requirements of subsidiaries (pre-tax basis) (b)	11.7	11.8	12.0	11.3	13.0
Total earnings as defined	$733.5	$620.1	$636.9	$609.2	$585.3
FIXED CHARGES:					
Interest expense	$215.6	$196.2	$187.1	$180.6	$172.8
Interest capitalized	0.5	0.2	1.3	1.0	0.5
Estimated interest component of rent expense	2.0	2.0	1.9	2.8	2.7
Preferred dividend requirements of subsidiaries (pre-tax basis) (b)	11.7	11.8	12.0	11.3	13.0
Total fixed charges as defined	$229.8	$210.2	$202.3	$195.7	$189.0
Ratio of Earnings to Fixed Charges (c)	3.19	2.95	3.15	3.11	3.10

(a) Includes net interest related to unrecognized tax benefits.

(b) Preferred dividend requirements of subsidiaries (pre-tax basis) are computed by dividing the preferred dividend requirements of subsidiaries by one hundred percent minus the respective annual effective income tax rate. Excludes the impact of charges related to Interstate Power and Light Company's and Wisconsin Power and Light Company's preferred stock redemptions in 2013.

(c) The ratio calculation in the above table relates to Alliant Energy Corporation's continuing operations.

Exhibit 12.2

INTERSTATE POWER AND LIGHT COMPANY

RATIO OF EARNINGS TO FIXED CHARGES AND RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED DIVIDEND REQUIREMENTS

	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(dollars in millions)				
EARNINGS:					
Net income	$227.0	$225.8	$196.2	$191.8	$188.3
Income tax benefit (a)	(10.9)	(5.9)	(22.7)	(48.9)	(36.3)
Income before income taxes	216.1	219.9	173.5	142.9	152.0
Fixed charges as defined	113.0	103.7	97.2	91.0	82.3
Total earnings as defined	$329.1	$323.6	$270.7	$233.9	$234.3
FIXED CHARGES:					
Interest expense	$112.4	$103.2	$96.8	$89.9	$81.3
Estimated interest component of rent expense	0.6	0.5	0.4	1.1	1.0
Total fixed charges as defined	$113.0	$103.7	$97.2	$91.0	$82.3
Ratio of Earnings to Fixed Charges	2.91	3.12	2.78	2.57	2.85
Preferred dividend requirements (pre-tax basis) (b)	$9.7	$9.9	$9.0	$7.6	$8.7
Fixed charges and preferred dividend requirements	$122.7	$113.6	$106.2	$98.6	$91.0
Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements	2.68	2.85	2.55	2.37	2.57

(a) Includes net interest related to unrecognized tax benefits.

(b) Preferred dividend requirements (pre-tax basis) are computed by dividing the preferred dividend requirements by one hundred percent minus the respective annual effective income tax rate. Excludes the impact of charges related to Interstate Power and Light Company's preferred stock redemption in 2013.

Exhibit 12.3

WISCONSIN POWER AND LIGHT COMPANY

RATIO OF EARNINGS TO FIXED CHARGES

	Year ended December 31,				
	2017	2016	2015	2014	2013
	(dollars in millions)				
EARNINGS:					
Net income	$186.6	$192.8	$177.6	$181.1	$179.1
Income taxes (a)	61.9	93.3	82.9	85.3	85.6
Income before income taxes	248.5	286.1	260.5	266.4	264.7
Fixed charges as defined	95.2	92.7	93.7	87.7	86.4
Adjustment for undistributed equity earnings	(0.6)	(11.5)	(4.5)	(6.4)	(8.3)
Total earnings as defined	$343.1	$367.3	$349.7	$347.7	$342.8
FIXED CHARGES:					
Interest expense	$93.8	$91.4	$92.4	$86.4	$85.0
Estimated interest component of rent expense	1.4	1.3	1.3	1.3	1.4
Total fixed charges as defined	$95.2	$92.7	$93.7	$87.7	$86.4
Ratio of Earnings to Fixed Charges	3.60	3.96	3.73	3.96	3.97

(a) Includes net interest related to unrecognized tax benefits.

Exhibit 21.1

ALLIANT ENERGY CORPORATION
SUBSIDIARIES OF THE REGISTRANT

The following are deemed to be significant subsidiaries of Alliant Energy Corporation as of December 31, 2017:

Name of Subsidiary	State of Incorporation
Interstate Power and Light Company	Iowa
Wisconsin Power and Light Company	Wisconsin

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-211148, 333-168812, 333-117654, and 333-51126 on Form S-8 and Registration Statement Nos. 333-222076 and 333-221355 on Form S-3 of our reports dated February 23, 2018, relating to the consolidated financial statements and financial statement schedules of Alliant Energy Corporation and subsidiaries (the "Company"), and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Alliant Energy Corporation for the year ended December 31, 2017.

/s/ DELOITTE & TOUCHE LLP
DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 23, 2018

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-222076-02 on Form S-3 of our report dated February 23, 2018, relating to the consolidated financial statements and financial statement schedule of Interstate Power and Light Company and subsidiary appearing in this Annual Report on Form 10-K of Interstate Power and Light Company for the year ended December 31, 2017.

/s/ DELOITTE & TOUCHE LLP
DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 23, 2018

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-222076-01 on Form S-3 of our report dated February 23, 2018, relating to the consolidated financial statements and financial statement schedule of Wisconsin Power and Light Company and subsidiary appearing in this Annual Report on Form 10-K of Wisconsin Power and Light Company for the year ended December 31, 2017.

/s/ DELOITTE & TOUCHE LLP
DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 23, 2018

Exhibit 31.1

Certification of the Chairman and Chief Executive Officer
for Alliant Energy Corporation

I, Patricia L. Kampling, certify that:

1. I have reviewed this annual report on Form 10-K of Alliant Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2018

/s/ Patricia L. Kampling

Patricia L. Kampling

Chairman and Chief Executive Officer

Exhibit 31.2

Certification of the Senior Vice President, Chief Financial Officer and Treasurer for Alliant Energy Corporation

I, Robert J. Durian, certify that:

1. I have reviewed this annual report on Form 10-K of Alliant Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2018

/s/ Robert J. Durian

Robert J. Durian

Senior Vice President, Chief Financial Officer and Treasurer

Exhibit 31.3

Certification of the Chairman and Chief Executive Officer
for Interstate Power and Light Company

I, Patricia L. Kampling, certify that:

1. I have reviewed this annual report on Form 10-K of Interstate Power and Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2018

/s/ Patricia L. Kampling

Patricia L. Kampling

Chairman and Chief Executive Officer

Exhibit 31.4

Certification of the Senior Vice President, Chief Financial Officer and Treasurer for Interstate Power and Light Company

I, Robert J. Durian, certify that:

1. I have reviewed this annual report on Form 10-K of Interstate Power and Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2018

/s/ Robert J. Durian

Robert J. Durian

Senior Vice President, Chief Financial Officer and Treasurer

Exhibit 31.5

Certification of the Chairman and Chief Executive Officer
for Wisconsin Power and Light Company

I, Patricia L. Kampling, certify that:

1. I have reviewed this annual report on Form 10-K of Wisconsin Power and Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2018

/s/ Patricia L. Kampling

Patricia L. Kampling

Chairman and Chief Executive Officer

Exhibit 31.6

Certification of the Senior Vice President, Chief Financial Officer and Treasurer for Wisconsin Power and Light Company

I, Robert J. Durian, certify that:

1. I have reviewed this annual report on Form 10-K of Wisconsin Power and Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2018

/s/ Robert J. Durian

Robert J. Durian

Senior Vice President, Chief Financial Officer and Treasurer

Exhibit 32.1

Written Statement of the Chief Executive Officer and Chief Financial Officer
Pursuant to 18 U.S.C. §1350

Solely for the purposes of complying with 18 U.S.C. §1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, we, the undersigned Chief Executive Officer and Chief Financial Officer of Alliant Energy Corporation (the "Company"), hereby certify, based on our knowledge, that the Annual Report on Form 10-K of the Company for the year ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Patricia L. Kampling
Patricia L. Kampling
Chairman and Chief Executive Officer

/s/ Robert J. Durian

Robert J. Durian

Senior Vice President, Chief Financial Officer and Treasurer

February 23, 2018

Exhibit 32.2

Written Statement of the Chief Executive Officer and Chief Financial Officer
Pursuant to 18 U.S.C. §1350

Solely for the purposes of complying with 18 U.S.C. §1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, we, the undersigned Chief Executive Officer and Chief Financial Officer of Interstate Power and Light Company (the "Company"), hereby certify, based on our knowledge, that the Annual Report on Form 10-K of the Company for the year ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Patricia L. Kampling

Patricia L. Kampling

Chairman and Chief Executive Officer

/s/ Robert J. Durian

Robert J. Durian

Senior Vice President, Chief Financial Officer and Treasurer

February 23, 2018

Exhibit 32.3

Written Statement of the Chief Executive Officer and Chief Financial Officer
Pursuant to 18 U.S.C. §1350

Solely for the purposes of complying with 18 U.S.C. §1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, we, the undersigned Chief Executive Officer and Chief Financial Officer of Wisconsin Power and Light Company (the "Company"), hereby certify, based on our knowledge, that the Annual Report on Form 10-K of the Company for the year ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Patricia L. Kampling

Patricia L. Kampling

Chairman and Chief Executive Officer

/s/ Robert J. Durian

Robert J. Durian

Senior Vice President, Chief Financial Officer and Treasurer

February 23, 2018

Section 1: 10-K (FORM 10-K)

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

(**X**) Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2017**

( ) Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from _____to_____

Commission File Number **0-53713**

OTTER TAIL CORPORATION

(Exact name of registrant as specified in its charter)

MINNESOTA	**27-0383995**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
215 SOUTH CASCADE STREET, BOX 496, FERGUS FALLS, MINNESOTA	**56538-0496**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **866-410-8780**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
COMMON SHARES, par value $5.00 per share	**The NASDAQ Stock Market LLC**

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ☑	Accelerated Filer ☐
Non-Accelerated Filer ☐	Smaller Reporting Company ☐
(Do not check if a smaller reporting company)	Emerging Growth Company ☐

If an emerging growth company, indicate by checkmark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

The aggregate market value of common stock held by non-affiliates, computed by reference to the last sales price on June 30, 2017 was **$1,500,154,049.**

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: **39,626,594 Common Shares ($5 par value) as of February 8, 2018.**

Documents Incorporated by Reference:

Proxy Statement for the 2018 Annual Meeting-Portions incorporated by reference into Part III

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OTTER TAIL CORPORATION
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S&P Global Market Intelligence

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Definitions

The following abbreviations or acronyms are used in the text. References in this report to "the Company", "we", "us" and "our" are to Otter Tail Corporation.

ADP	Advance Determination of Prudence
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AQCS	Air Quality Control System
ARO	Accumulated Asset Retirement Obligation
ASC	Accounting Standards Codification
ASC 606	ASC Topic 606 – *Revenue from Contracts with Customers*
ASC 718	ASC Topic 718 – *Compensation—Stock Compensation*
ASC 820	ASC Topic 820 – *Fair Value Measurement*
ASC 980	ASC Topic 980 – *Regulated Operations*
ASM	Ancillary Services Market
ASU	Accounting Standards Update
BACT	Best-Available Control Technology
BTD	BTD Manufacturing, Inc.
Btu	British Thermal Unit
CAA	Clean Air Act
CCMC	Coyote Creek Mining Company, L.L.C.
CCR	Coal Combustion Residuals
CIP	Conservation Improvement Program
CO_2	carbon dioxide
CON	Certificate of Need
CPEC	Central Power Electric Cooperative
CPP	Clean Power Plan

CSAPR	Cross-State Air Pollution Rule
CWIP	Construction Work in Progress
D.C. Circuit	United States Court of Appeals for the District of Columbia
DRR	Data Requirement Rule
ECR	Environmental Cost Recovery
EDF	EDF Renewable Development, Inc.
EEI	Edison Electric Institute
EEP	Energy Efficiency Plan
EPA	Environmental Protection Agency
ESSRP	Executive Survivor and Supplemental Retirement Plan
Exchange Act	The Securities Exchange Act of 1934
FASB	Financial Accounting Standards Board
FCA	Fuel Clause Adjustment
FERC	Federal Energy Regulatory Commission
Foley	Foley Company
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas
Impulse	Impulse Manufacturing, Inc.
IRP	Integrated Resource Plan
JPMS	J.P. Morgan Securities LLC
kV	kiloVolt
kW	kiloWatt
kwh	kilowatt-hour
LSA	Lignite Sales Agreement
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator, Inc.
MISO Tariff	MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff
MNCIP	Minnesota Conservation Improvement Program
MNDOC	Minnesota Department of Commerce
MPCA	Minnesota Pollution Control Agency
MPU Act	The Minnesota Public Utilities Act
MPUC	Minnesota Public Utilities Commission

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MRO	Midwest Reliability Organization
MVP	Multi-Value Project
MW	megawatts
NAAQS	National Ambient Air Quality Standards
NAEMA	North American Energy Marketers Association
NDPSC	North Dakota Public Service Commission
NDRRA	North Dakota Renewable Resource Adjustment
NERC	North American Electric Reliability Corporation
NETOs	New England Transmission Owners
NPDES	National Pollutant Discharge Elimination System
Northern Pipe	Northern Pipe Products, Inc.
NO_x	nitrogen oxide
NSPS	New Source Performance Standards
OTP	Otter Tail Power Company
PACE	Partnership in Assisting Community Expansion
ppb	parts per billion
PSD	Prevention of Significant Deterioration
PTCs	Production Tax Credits
PVC	Polyvinyl Chloride
ROE	Return on Equity
RSG	Revenue Sufficiency Guarantee
RTO Adder	Incentive of additional 50-basis points for Regional Transmission Organization participation
SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission
SF_6	sulfur hexaflouride
SO_2	sulfur dioxide
SPP	Southwest Power Pool
Standex	Standex International Corporation
T.O. Plastics	T.O. Plastics, Inc.
TCR	Transmission Cost Recovery
TCJA	2017 Tax Cuts and Jobs Act
Varistar	Varistar Corporation
VIE	Variable Interest Entity
Vinyltech	Vinyltech Corporation
WIIN	Water Infrastructure Improvements for the Nation

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PART I

Item 1. BUSINESS

(a) General Development of Business

Otter Tail Power Company was incorporated in 1907 under the laws of the State of Minnesota. In 2001, the name was changed to "Otter Tail Corporation" to more accurately represent the broader scope of consolidated operations and the name Otter Tail Power Company (OTP) was retained for use by the electric utility. On July 1, 2009 Otter Tail Corporation completed a holding company reorganization whereby OTP, which had previously been operated as a division of Otter Tail Corporation, became a wholly owned subsidiary of the new parent holding company named Otter Tail Corporation (the Company). The new parent holding company was incorporated in June 2009 under the laws of the State of Minnesota in connection with the holding company reorganization. The Company's executive offices are located at 215 South Cascade Street, P.O. Box 496, Fergus Falls, Minnesota 56538-0496 and 4334 18th Avenue SW, Suite 200, P.O. Box 9156, Fargo, North Dakota 58106-9156. The Company's telephone number is (866) 410-8780.

The Company makes available free of charge at its website (www.ottertail.com) its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, Forms 3, 4 and 5 filed on behalf of directors and executive officers and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission (SEC). Information on the Company's website is not deemed to be incorporated by reference into this Annual Report on Form 10-K.

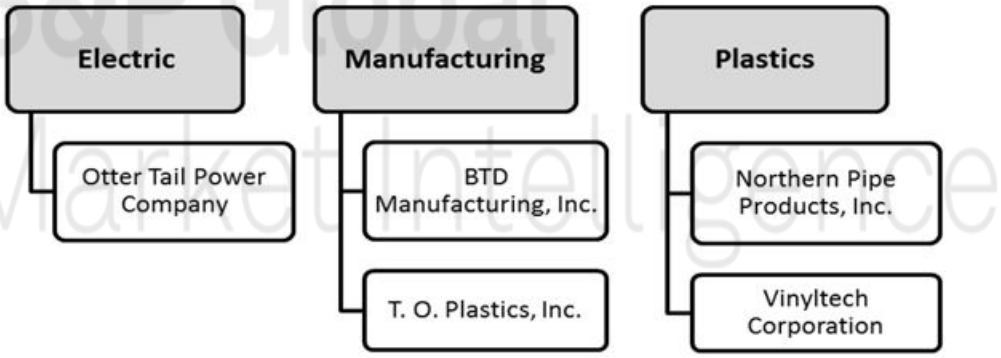
Otter Tail Corporation and its subsidiaries conduct business primarily in the United States. The Company had approximately 2,097 full-time employees in its continuing operations at December 31, 2017. The Company's businesses have been classified in three segments to be consistent with its business strategy and the reporting and review process used by the Company's chief operating decision maker. The three segments are Electric, Manufacturing and Plastics.

From 2011 through 2015, the Company sold several businesses in order to realign its business portfolio to reduce its risk profile and dedicate a greater portion of its resources toward electric utility operations. Recent divestitures include:

- In 2012 the Company completed the sale of the assets of its former wind tower company.
- In 2013 the Company sold substantially all the assets of its former dock and boatlift company.
- In 2015 the Company sold the assets of AEV, Inc., its former energy and electrical construction contractor and the Company sold Foley Company, its former water, wastewater, power and industrial construction contractor. With the sale of these two companies the Company eliminated its Construction segment.

On September 1, 2015 the Company acquired the assets of Impulse Manufacturing Inc. (Impulse) of Dawsonville, Georgia, now operating under the name BTD-Georgia, for $29.3 million. BTD-Georgia offers a wide range of metal fabrication services ranging from simple laser cutting services and high volume stamping to complex weldments and assemblies for metal fabrication buyers and original equipment manufacturers.

The chart below indicates the companies included in each of the Company's reporting segments.



- Electric includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota by OTP. In addition, OTP is a participant in the Midcontinent Independent System Operator, Inc. (MISO) markets. OTP's operations have been the Company's primary business since 1907.

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- Manufacturing consists of businesses in the following manufacturing activities: contract machining, metal parts stamping, fabrication and painting, and production of plastic thermoformed horticultural containers, life science and industrial packaging, and material handling components. These businesses have manufacturing facilities in Georgia, Illinois and Minnesota and sell products primarily in the United States.
- Plastics consists of businesses producing polyvinyl chloride (PVC) pipe at plants in North Dakota and Arizona. The PVC pipe is sold primarily in the upper Midwest and Southwest regions of the United States.

OTP is a wholly owned subsidiary of the Company. The Company's manufacturing and plastic pipe businesses are owned by its wholly owned subsidiary, Varistar Corporation (Varistar). The Company's corporate operating costs include items such as corporate staff and overhead costs, the results of the Company's captive insurance company and other items excluded from the measurement of operating segment performance that are not allocated to its subsidiary companies. Corporate assets consist primarily of cash, prepaid expenses, investments and fixed assets. Corporate is not an operating segment. Rather, it is added to operating segment totals to reconcile to totals on the Company's consolidated financial statements.

The Company has lowered its overall risk by investing in rate base growth opportunities in its Electric segment and divesting certain nonelectric operating companies that no longer fit the Company's portfolio criteria. This strategy has provided a more predictable earnings stream, improved the Company's credit quality and preserved its ability to fund the dividend. The Company's goal is to deliver annual growth in earnings per share between four to seven percent over the next several years, using 2017 diluted earnings per share from continuing operations as the base for measurement. The growth is expected to come from the substantial increase in the Company's regulated utility rate base and from planned increased earnings from existing capacity in place at the Company's manufacturing and plastic pipe businesses, including the 2015 acquisition of BTD-Georgia and the facilities expansion and addition of paint services at BTD Manufacturing Inc.'s Minnesota facilities completed in 2016. The Company will continue to

review its business portfolio to see where additional opportunities exist to improve its risk profile, improve credit metrics and generate additional sources of cash to support the growth opportunities in its electric utility. The Company will also evaluate opportunities to allocate capital to potential acquisitions in its Manufacturing and Plastics segments. Over time, the Company expects the electric utility business will provide approximately 75% to 85% of its overall earnings. The Company expects its manufacturing and plastic pipe businesses will provide 15% to 25% of its earnings, and will continue to be a fundamental part of its strategy. The actual mix of earnings from continuing operations in 2017 was 69% from the electric utility and 31% from the manufacturing and plastic pipe businesses, including unallocated corporate costs.

The Company maintains criteria in evaluating whether its operating companies are a strategic fit. The operating company should:

- Maintain a threshold level of net earnings and a return on invested capital in excess of the Company's weighted average cost of capital.
- Have a strategic differentiation from competitors and a sustainable cost advantage.
- Operate within a stable and growing industry and be able to quickly adapt to changing economic cycles.
- Have a strong management team committed to operational excellence.

For a discussion of the Company's results of operations, see "Management's Discussion and Analysis of Financial Condition and Results of Operations," on pages 37 through 59 of this Annual Report on Form 10-K.

(b) Financial Information about Industry Segments

The Company is engaged in businesses classified into three segments: Electric, Manufacturing and Plastics. Financial information about the Company's segments and geographic areas is included in note 2 of "Notes to Consolidated Financial Statements" on pages 76 through 79 of this Annual Report on Form 10-K.

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(c) Narrative Description of Business

ELECTRIC

General

Electric includes OTP which is headquartered in Fergus Falls, Minnesota, and provides electricity to more than 130,000 customers in a service area encompassing 70,000 square miles of western Minnesota, eastern North Dakota and northeastern South Dakota. The Company derived 51%, 53% and 52% of its consolidated operating revenues and 72%, 81% and 80% of its consolidated operating income from its Electric segment for the years ended December 31, 2017, 2016 and 2015, respectively.

The breakdown of retail electric revenues by state is as follows:

State	2017	2016
Minnesota	52.8%	53.0%
North Dakota	38.5	38.4
South Dakota	8.7	8.6
Total	100.0%	100.0%

The territory served by OTP is predominantly agricultural. The aggregate population of OTP's retail electric service area is approximately 230,000. In this service area of 422 communities and adjacent rural areas and farms, approximately 126,000 people live in communities having a population of more than 1,000, according to the 2010 census. The only communities served which have a population in excess of 10,000 are Jamestown, North Dakota (15,427); Bemidji, Minnesota (13,431); and Fergus Falls, Minnesota (13,138). As of December 31, 2017 OTP served 132,146 customers. Although there are relatively few large customers, sales to commercial and industrial customers are significant. One customer accounted for 12% of the 2017 revenue from the Electric segment.

The following table provides a breakdown of electric revenues by customer category. All other sources include gross wholesale sales from utility generation and sales to municipalities.

Customer Category	2017	2016
Commercial	35.2%	36.1%
Residential	31.1	30.8
Industrial	31.8	31.0
All Other Sources	1.9	2.1
Total	100.0%	100.0%

Capacity and Demand

As of December 31, 2017 OTP's owned net-plant dependable kilowatt (kW) capacity was:

Baseload Plants	
Big Stone Plant	258,100 kW
Coyote Station	149,800
Hoot Lake Plant	139,700
Total Baseload Net Plant	547,600 kW
Combustion Turbine and Small Diesel Units	109,900 kW
Hydroelectric Facilities	2,800 kW
Owned Wind Facilities (rated at nameplate)	
Luverne Wind Farm (33 turbines)	49,500 kW
Ashtabula Wind Center (32 turbines)	48,000
Langdon Wind Center (27 turbines)	40,500

Total Owned Wind Facilities	138,000 kW

The baseload net plant capacity for Big Stone Plant and Coyote Station constitutes OTP's ownership percentages of 53.9% and 35%, respectively. OTP owns 100% of the Hoot Lake Plant. During 2017, about 56% of OTP's retail kilowatt-hour (kwh) sales were supplied from OTP generating plants with the balance supplied by purchased power.

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In addition to the owned facilities described above, OTP had the following purchased power agreements in place on December 31, 2017:

Purchased Wind Power Agreements (rated at nameplate and greater than 2,000 kW)	
Ashtabula Wind III	62,400kW
Edgeley	21,000
Langdon	19,500
Total Purchased Wind	102,900kW
Purchase of Capacity (in excess of 1 year and 500 kW)	
Great River Energy[1]	80,000kW

[1] *80,000 kW through May 2019 and 50,000 kW June 2019 – May 2021.*

OTP has a direct control load management system which provides some flexibility to OTP to effect reductions of peak load. OTP also offers rates to customers which encourage off-peak usage.

OTP's capacity requirement is based on MISO Module E requirements. OTP is required to have sufficient Zonal Resource Credits to meet its monthly weather-normalized forecast demand, plus a reserve obligation. OTP met its MISO obligation for the 2017-2018 MISO planning year. OTP generating capacity combined with additional capacity under purchased power agreements (as described above) and load management control capabilities is expected to meet 2018 system demand and MISO reserve requirements.

Fuel Supply

Coal is the principal fuel burned at the Big Stone, Coyote and Hoot Lake generating plants. Coyote Station, a mine-mouth facility, burns North Dakota lignite coal. Hoot Lake Plant and Big Stone Plant burn western subbituminous coal.

The following table shows the sources of energy used to generate OTP's net output of electricity for 2017 and 2016:

	2017		2016	
Sources	Net kwhs Generated (Thousands)	% of Total kwhs Generated	Net kwhs Generated (Thousands)	% of Total kwhs Generated
Subbituminous Coal	1,440,017	49.1%	1,419,901	50.3%
Lignite Coal	920,451	31.4	844,225	29.9
Wind and Hydro	534,474	18.2	517,396	18.4
Natural Gas and Oil	36,703	1.3	40,257	1.4
Total	2,931,645	100.0%	2,821,779	100.0%

OTP has the following primary coal supply agreements:

Plant	Coal Supplier	Type of Coal	Expiration Date
Big Stone Plant	Contura Coal Sales, LLC	Wyoming subbituminous	December 31, 2019
Big Stone Plant	Peabody COALSALES, LLC	Wyoming subbituminous	December 31, 2018
Coyote Station	Coyote Creek Mining Company, L.L.C.	North Dakota lignite	December 31, 2040
Hoot Lake Plant	Cloud Peak Energy Resources LLC	Montana subbituminous	December 31, 2023

The above contracts for Big Stone Plant do not provide for 100% of Big Stone Plant's anticipated coal needs in 2018 and 2019.

In October 2012 the Coyote Station owners, including OTP, entered into a lignite sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (CCMC), a subsidiary of The North American Coal Corporation, for the purchase of coal to meet the coal supply requirements of Coyote Station for the period beginning in May 2016 and ending in December 2040. The price per ton being paid by the Coyote Station owners under the LSA reflects the cost of production, along with an agreed profit and capital charge. The LSA provides for the Coyote Station owners to purchase the membership interests in CCMC in the event of certain early termination events and also at the end of the term of the LSA.

OTP's coal supply requirements for Hoot Lake Plant are secured under contract through December 2023.

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Railroad transportation services to the Big Stone Plant and Hoot Lake Plant are provided under a common carrier rate by the BNSF Railway. The common carrier rate is subject to a mileage-based fuel surcharge. The basis for the fuel surcharge is the U.S. average price of retail on-highway diesel fuel. No coal transportation agreement is needed for Coyote Station as a mine-mouth facility.

The average cost of fuel consumed (including handling charges to the plant sites) per million British Thermal Units (Btu) for the years 2017, 2016, and 2015 was $2.224, $2.146 and $2.281, respectively.

General Regulation

OTP is subject to regulation of rates and other matters in each of the three states in which it operates and by the federal government for certain interstate operations.

S&P Global Market Intelligence

A breakdown of electric rate regulation by each jurisdiction follows:

		2017		2016	
Rates	Regulation	% of Electric Revenues	% of kwh Sales	% of Electric Revenues	% of kwh Sales
MN Retail Sales	MN Public Utilities Commission	46.4%	54.0%	47.5%	54.0%
ND Retail Sales	ND Public Service Commission	33.9	37.1	34.4	37.1
SD Retail Sales	SD Public Utilities Commission	7.7	8.9	7.8	8.9
Transmission & Wholesale	Federal Energy Regulatory Commission	12.0	--	10.3	--
Total		100.0%	100.0%	100.0%	100.0%

OTP operates under approved retail electric tariffs in all three states it serves. OTP has an obligation to serve any customer requesting service within its assigned service territory. The pattern of electric usage can vary dramatically during a 24-hour period and from season to season. OTP's tariffs are designed to recover the costs of providing electric service. To the extent peak usage can be reduced or shifted to periods of lower usage, the cost to serve all customers is reduced. In order to shift usage from peak times, OTP has approved tariffs in all three states for residential demand control, general service time of use and time of day, real-time pricing, and controlled and interruptible service. Each of these specialized rates is designed to improve efficient use of OTP resources, while giving customers more control over their electric bill. OTP also has approved tariffs in its three service territories which allow qualifying customers to release and sell energy back to OTP when wholesale energy prices make such transactions desirable.

With a few minor exceptions, OTP's electric retail rate schedules currently provide for adjustments in rates based on the cost of fuel delivered to OTP's generating plants, as well as for adjustments based on the cost of electric energy purchased by OTP. OTP also credits certain margins from wholesale sales to the fuel and purchased power adjustment. The adjustments for fuel and purchased power costs are presently based on a two month moving average in Minnesota and by the Federal Energy Regulatory Commission (FERC), a three month moving average in South Dakota and a four month moving average in North Dakota. These adjustments are applied to the next billing period after becoming applicable. These adjustments also include an over or under recovery mechanism, which is calculated on an annual basis in Minnesota and on a monthly basis in North Dakota and South Dakota.

2017 Tax Cuts and Jobs Act (TCJA)

The TCJA reduced the Federal Income Tax rate from 35% to 21%. Currently, all OTP rates have been developed using a 35% tax rate. The Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the FERC have all initiated dockets or proceedings to begin working with utilities to assess the impact of the lower income tax rate under the TCJA on electric rates, and to develop regulatory strategies to incorporate the tax change into future rates, if warranted. The MPUC required its regulated utilities to make filings by January 30, 2018 and February 15, 2018, but has not made a determination on rate treatment. OTP currently has an active rate case in North Dakota and anticipates incorporating the impact of the tax changes to North Dakota rates within that proceeding. The SDPUC required initial comments by February 1, 2018 and indicated that revenues collected subsequent to December 31, 2017 would be subject to refund, pending determination of the impacts of the TCJA. OTP is still assessing these impacts and will continue to work with the respective Commissions to determine if any rate adjustments are necessary and, if so, to determine the appropriate timing and approach for making those adjustments.

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Major Capital Expenditure Projects

Below are descriptions of OTP's major capital expenditure projects that have had, or will have, a significant impact on OTP's revenue requirements, rates and alternative revenue recovery mechanisms, followed by summaries of the material regulations of each jurisdiction applicable to OTP's electric operations, as well as any specific electric rate proceedings during the last three years with the MPUC, the NDPSC, the SDPUC and the FERC. The Company's manufacturing and plastic pipe businesses are not subject to direct regulation by any of these agencies.

Big Stone South–Ellendale Multi-Value Transmission Project (MVP)—This is a 345 kiloVolt (kV) transmission line that will extend 163 miles between a substation near Big Stone City, South Dakota and a substation near Ellendale, North Dakota. OTP jointly developed this project with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., and the parties will have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff) in December 2011. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple areas within the MISO region. The cost allocation is designed to ensure the costs of transmission projects with regional benefits are properly assigned to those who benefit. Construction began on this line in the second quarter of 2016 and is expected to be completed in 2019. OTP's capitalized costs on this project as of December 31, 2017 were approximately $90 million, which includes assets that are 100% owned by OTP.

Big Stone South–Brookings MVP—This 345-kV transmission line extends approximately 70 miles between a substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Northern States Power – Minnesota, a subsidiary of Xcel Energy Inc., jointly developed this project and the parties have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Tariff in December 2011. Construction began on this line in the third quarter of 2015 and the line was energized on September 8, 2017. OTP's capitalized costs on this project as of December 31, 2017 were approximately $73 million, which includes assets that are 100% owned by OTP.

Fargo–Monticello 345-kV Project—OTP invested approximately $81 million and has a 14.2% ownership interest in the jointly-owned assets of this 240-mile transmission line, and owns 100% of certain assets of the project. The final phase of this project was energized on April 2, 2015.

Brookings–Southeast Twin Cities 345-kV Project—OTP invested approximately $26 million and has a 4.8% ownership interest in this 250-mile transmission line. The MISO granted unconditional approval of this project as an MVP under the MISO Tariff in December 2011. The final segments of this line were energized on March 26, 2015.

Big Stone Plant Air Quality Control System (AQCS)—OTP completed construction and testing of the Big Stone Plant AQCS in the fourth quarter of 2015 and placed the AQCS into commercial operation on December 29, 2015. OTP's capitalized cost of the project, excluding allowance for funds used during construction, was approximately $200 million.

Recovery of OTP's major transmission investments is through the MISO Tariff (several as MVPs) and, currently, North Dakota and South Dakota Transmission Cost Recovery (TCR) Riders.

Minnesota

Under the Minnesota Public Utilities Act (the MPU Act), OTP is subject to the jurisdiction of the MPUC with respect to rates, issuance of securities, depreciation rates, public utility services, construction of major utility facilities, establishment of exclusive assigned service areas, contracts and arrangements with subsidiaries and other

affiliated interests, and other matters. The MPUC has the authority to assess the need for large energy facilities and to issue or deny certificates of need, after public hearings, within one year of an application to construct such a facility.

Pursuant to the Minnesota Power Plant Siting Act, the MPUC has authority to select or designate sites in Minnesota for new electric power generating plants (50,000 kW or more) and routes for transmission lines (100 kV or more) in an orderly manner compatible with environmental preservation and the efficient use of resources, and to certify such sites and routes as to environmental compatibility after an environmental impact study has been conducted by the Minnesota Department of Commerce (MNDOC) and the Office of Administrative Hearings has conducted contested case hearings.

The Minnesota Division of Energy Resources, part of the MNDOC, is responsible for investigating all matters subject to the jurisdiction of the MNDOC or the MPUC, and for the enforcement of MPUC orders. Among other things, the MNDOC is authorized to collect and analyze data on energy including the consumption of energy, develop recommendations as to energy policies for the governor and the legislature of Minnesota and evaluate policies governing the establishment of rates and prices for energy as related to energy conservation. The MNDOC also has the power, in the event of energy shortage or for a long-term basis, to prepare and adopt regulations to conserve and allocate energy.

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2016 General Rate Case—The MPUC rendered its final decision in OTP's 2016 general rate case in March 2017 and issued its written order on May 1, 2017. Pursuant to the order, OTP's allowed rate of return on rate base decreased from 8.61% to 7.5056% and its allowed rate of return on equity decreased from 10.74% to 9.41%. On July 6, 2017 the MPUC denied OTP's request for reconsideration of certain of the MPUC's rulings in the rate case and confirmed its May 1, 2017 order.

The MPUC's order also included: (1) the determination that all costs (including FERC allocated costs and revenues) of the Big Stone South–Brookings and Big Stone South–Ellendale MVP projects will be included in the Minnesota TCR rider and jurisdictionally allocated to OTP's Minnesota customers, and (2) approval of OTP's proposal to transition rate base, expenses and revenues from Environmental Cost Recovery (ECR) and TCR riders to base rate recovery, with the transition occurring when final rates are implemented. The rate base balances, expense levels and revenue levels existing in the riders at the time of implementation of final rates were used to establish the amounts transitioned to base rates. Certain MISO expenses and revenues will remain in the TCR rider to allow for the ongoing refund or recovery of these variable revenues and costs.

Information on interim and final rate increases and interim revenue refunds accrued is detailed in the tables below:

($ in thousands)	Interim Rates Authorized April 14, 2016	Final Rates
Revenue Increase – Annualized based on Test Year Data	$ 16,816	$ 10,471
Revenue Percent Increase	9.56%	5.34%
Return on Rate Base	8.07%	7.5056%
Jurisdictional Rate Base based on Test Year Data	$ 483,000	$ 471,000
Return on Equity	10.40%	9.41%
Based on Equity to Total Capital of	52.50%	52.50%
Debt to Total Capital	47.50%	47.50%

Interim Revenue *(in thousands)*	April 16, 2016 through October 31, 2017
Billed	$ 23,289
Accrued Refund	$ 8,779
Net Interim Revenue	$ 14,510
Interest on Refundable Amount	$ 265
Final Refund	$ 9,044

The final interim rate refund, including interest was applied as a credit to Minnesota customers' electric bills beginning November 17, 2017.

In addition to the interim rate refund, OTP will be required to refund the difference between (1) amounts collected under its Minnesota ECR and TCR riders based on the return on equity (ROE) approved in its most recent rider update and (2) amounts that would have been collected based on the lower 9.41% ROE approved in its 2016 general rate case going back to April 16, 2016, the date interim rates were implemented. As of October 31, 2017 the revenues collected under the Minnesota ECR and TCR riders subject to refund due to the lower ROE rate and other adjustments were $0.9 million and $1.4 million, respectively. These amounts will be refunded to Minnesota customers over a 12-month period through reductions in the Minnesota ECR and TCR rider rates in effect November 1, 2017, as approved by the MPUC. The TCR rate is provisional and subject to revision under a separate docket.

Integrated Resource Plan (IRP)—Minnesota law requires utilities to submit to the MPUC for approval a 15-year advance IRP. A resource plan is a set of resource options a utility could use to meet the service needs of its customers over a forecast period, including an explanation of the utility's supply and demand circumstances, and the extent to which each resource option would be used to meet those service needs. The MPUC's findings of fact and conclusions regarding resource plans shall be considered prima facie evidence, subject to rebuttal, in Certificate of Need (CON) hearings, rate reviews and other proceedings. Typically, the filings are submitted every two years.

On April 26, 2017 the MPUC issued an order approving OTP's 2017-2031 IRP filing with modifications and setting requirements for the next resource plan. The approved plan with modifications included the following items:

- The addition of 200 megawatts (MW) of wind resources in the 2018 to 2020 timeframe.
- The addition of 30 MW of solar resources by 2020 to comply with Minnesota's Solar Energy Standard.
- The addition of up to 250 MW of peaking capacity in 2021.
- Average annual energy savings of 46.8 gigawatt-hours (1.6% of retail sales).
- Modification of OTP's IRP to include 100 MW to 200 MW of wind in the 2022 to 2023 timeframe.

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The MPUC ordered OTP to file its next IRP no later than June 3, 2019.

Fuel and Purchased Power Costs Recovery—On December 19, 2017, the MPUC issued an order authorizing the implementation of a new fuel clause adjustment mechanism to be implemented July 1, 2019. Prior to implementation, OTP will be required to submit forecasted monthly fuel cost rates for the twelve-month period beginning July 1, 2019.

Upon approval by the MPUC, those rates will be published in advance of each year to give customers notice of the next years' monthly fuel rates, and those will be the rates OTP will charge per kWh to cover fuel costs. OTP will track its actual costs throughout the year and then file an annual report with the MPUC comparing the actual cost per kWh to the billed cost per kwh to determine if any over or under collection of costs occurred. OTP would refund any over-collections, or in the case of an under-collection, need to show prudence of costs before allowed recovery of under-collections. The refund of any over-collection or recovery of any under-collection would be handled through a true-up mechanism. OTP will be working with other Minnesota utilities, the MNDOC and other stakeholders to address questions and further develop the mechanism prior to implementation.

On implementation of the order, OTP will be required to reserve revenues, accrue a liability and refund amounts of fuel and purchased power and related costs collected in excess of amounts for which it was granted recovery in its rate case or annual fuel cost adjustment filing that preceded the annual period of recovery. OTP will no longer be able to accrue revenue and a regulatory asset for fuel and purchased power costs incurred in excess of amounts it was allowed to recover unless and until recovery of those excess amounts has been granted through a true-up mechanism that will be provided for in a subsequent order to be issued by the MPUC. This mechanism for recovery of fuel and purchased power and related costs incurred to serve Minnesota customers could result in reductions in Electric segment operating income margins and variability in the Company's consolidated net income in future periods if those costs exceed forecasted costs.

Renewable Energy Standards, Conservation, Renewable Resource Riders—Minnesota law favors conservation over the addition of new resources. In addition, Minnesota law requires the use of renewable resources where new supplies are needed, unless the utility proves that a renewable energy facility is not in the public interest. An existing environmental externality law requires the MPUC, to the extent practicable, to quantify the environmental costs associated with each method of electricity generation, and to use such monetized values in evaluating generation resources. The MPUC must disallow any nonrenewable rate base additions (whether within or outside of the state) or any related rate recovery, and may not approve any nonrenewable energy facility in an IRP, unless the utility proves that a renewable energy facility is not in the public interest. The state has prioritized the acceptability of new generation with wind and solar ranked first, the highest ranking and coal and nuclear ranked fifth, the lowest ranking. The MPUC's currently applicable estimate of the range of costs of future carbon dioxide (CO_2) regulation to be used in modeling analyses for resource plans is $9.00 to $34.00 per ton of CO_2 commencing in 2022. The MPUC is required to annually update these estimates. The MNDOC and the Minnesota Pollution Control Agency (MPCA) have recommended the new range to be $5.00 to $25.00 per ton beginning in 2025. The MPUC will likely rule on this docket during the second quarter of 2018.

Minnesota has a renewable energy standard which requires OTP to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 17% by 2016; 20% by 2020 and 25% by 2025. In addition, Minnesota law requires 1.5% of total Minnesota electric sales by public utilities to be supplied by solar energy by 2020. For a public utility with between 50,000 and 200,000 retail electric customers, such as OTP, at least 10% of the 1.5% requirement must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 40 kWs or less. If approved by the MPUC, individual customer subscriptions to an OTP-operated community solar garden program of 40 kWs or less could be applied toward the 10% requirement. OTP has purchased enough utility-scale solar energy credits to meet its expected 2020 Minnesota obligation. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards. OTP has acquired sufficient renewable resources to currently comply with Minnesota renewable energy standards. OTP is evaluating potential options for maintaining compliance and meeting the solar energy standard. Projected capital expenditures include $30 million for solar generation in 2021. OTP's compliance with the Minnesota renewable energy standard will be measured through the Midwest Renewable Energy Tracking System.

Under the Next Generation Energy Act of 2007, an automatic adjustment mechanism was established to allow Minnesota electric utilities to recover investments and costs incurred to satisfy the requirements of the renewable energy standard. The MPUC is authorized to approve a rate schedule rider to enable utilities to recover the costs of qualifying renewable energy projects that supply renewable energy to Minnesota customers. Cost recovery for qualifying renewable energy projects can be authorized outside of a rate case proceeding, provided that such renewable projects have received previous MPUC approval. Renewable resource costs eligible for recovery may include return on investment, depreciation, operation and maintenance costs, taxes, renewable energy delivery costs and other related expenses.

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Minnesota Conservation Improvement Programs (MNCIP)—Under Minnesota law, every regulated public utility that furnishes electric service must make annual investments and expenditures in energy conservation improvements, or make a contribution to the state's energy and conservation account, in an amount equal to at least 1.5% of its gross operating revenues from service provided in Minnesota. On May 25, 2016 the MPUC adopted the MNDOC's proposed changes to the MNCIP financial incentive. The new model provides utilities an incentive of 13.5% of 2017 net benefits, 12% of 2018 net benefits and 10% of 2019 net benefits, assuming the utility achieves 1.7% savings compared to retail sales. The new model will reduce the MNCIP financial incentive by approximately 50% compared to the previous incentive mechanism.

The MNDOC may require a utility to make investments and expenditures in energy conservation improvements whenever it finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of a new supply of energy. Such MNDOC orders can be appealed to the MPUC. Investments made pursuant to such orders generally are recoverable costs in rate cases, even though ownership of the improvement may belong to the property owner rather than the utility. OTP recovers conservation related costs not included in base rates under the MNCIP through the use of an annual recovery mechanism approved by the MPUC.

On July 9, 2015 the MPUC granted approval of OTP's 2014 financial incentive of $3.0 million along with an updated surcharge with an effective date of October 1, 2015.

Based on results from the 2015 MNCIP program year, OTP recognized a financial incentive of $4.2 million. The 2015 MNCIP program resulted in an approximate 39% increase in energy savings compared to 2014 program results. On April 1, 2016 OTP requested approval for recovery of its 2015 MNCIP program costs not included in base rates, a $4.3 million financial incentive and an update to the MNCIP surcharge from the MPUC. On July 19, 2016 the MPUC issued an order approving OTP's request with an effective date of October 1, 2016.

Based on results from the 2016 MNCIP program year, OTP recognized MNCIP financial incentives of $5.1 million in 2016, which included a $0.1 million true-up of 2015 financial incentives earned. The 2016 program resulted in an approximate 18% increase in energy savings compared to 2015 program results. On March 31, 2017 OTP requested approval for recovery of its 2016 MNCIP program costs not included in base rates, $5.0 million in performance incentives and an update to the MNCIP surcharge from the MPUC. On September 15, 2017 the MPUC issued an order approving OTP's request with an effective date of October 1, 2017.

Based on results from the 2017 MNCIP program year, OTP recognized a financial incentive of $2.6 million in 2017. The 2017 program resulted in an approximate 10% decrease in energy savings compared to 2016 program results. OTP will request approval for recovery of its 2017 MNCIP program costs not included in base rates, a $2.6 million financial incentive and an update to the MNCIP surcharge from the MPUC by April 1, 2018.

In 2016 the MNDOC opened a docket to investigate how investor-owned utilities calculate their avoided costs pertaining to transmission and distribution. Avoided costs are the basis of MNCIP program benefits which, going forward, will establish OTP's financial incentive. On May 23, 2016 the MNDOC accepted OTP's 2017 avoided costs calculation, but is requiring Minnesota investor-owned utilities to undergo an analysis of transmission and distribution avoided costs for 2018 and 2019. OTP is participating in a stakeholder group with the MNDOC, Xcel Energy Inc., and Minnesota Power to determine the best method for calculating avoided costs. On September 29, 2017, MNDOC issued a decision on utilities' transmission and distribution avoided costs. The decision did not require OTP to update avoided costs or cost-effectiveness for the 2017-2019 MNCIP triennial plan. The decision directed OTP to use the discrete approach methodology to calculate avoided transmission and distribution costs as part of

OTP's 2020-2022 MNCIP triennial plans.

Transmission Cost Recovery Rider—The MPU Act provides a mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that have been previously approved by the MPUC in a CON proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or exempt from the requirement to obtain a Minnesota CON. The MPUC may also authorize cost recovery via such TCR riders for charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the MISO to benefit the utility or integrated transmission system. The MPU Act also authorizes TCR riders to recover the costs of new transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that state, and determined by the MISO to benefit the utility or integrated transmission system. Finally, under certain circumstances, the MPU Act also authorizes TCR riders to recover the costs associated with distribution planning and investments in distribution facilities to modernize the utility grid. Such TCR riders allow a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule. MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from other MISO customers.

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On February 18, 2015 the MPUC approved OTP's 2014 TCR rider annual update with an effective date of March 1, 2015. OTP filed an annual update to its Minnesota TCR rider on September 30, 2015 requesting revenue recovery of approximately $7.8 million. A supplemental filing to the update was made on December 21, 2015 to address an issue surrounding the proration of accumulated deferred income taxes and, in an unrelated adjustment, the TCR rider update revenue request was reduced to $7.2 million. On March 9, 2016 the MPUC issued an order approving OTP's annual update to its TCR rider, with an effective date of April 1, 2016.

OTP filed an update to its TCR rider on April 29, 2016 to incorporate the impact of bonus depreciation for income taxes, an adjusted rate of return on rate base and allocation factors to align with its 2016 general rate case request. On July 5, 2016 the MPUC issued an order approving the proposed rates on a provisional basis, as recommended by the MNDOC. The proposed rate changes went into effect on September 1, 2016. On October 30, 2017 the MPUC issued an order resetting OTP's Minnesota TCR rates in effect since September 1, 2016 to refund $3.3 million previously collected under the rider, beginning November 1, 2017. The reset rates were approved on a provisional basis in the Minnesota general rate case docket, subject to revision in a separate docket.

In OTP's 2016 general rate case order issued on May 1, 2017, the MPUC ordered OTP to include, in the TCR rider retail rate base, Minnesota's jurisdictional share of OTP's investment in the Big Stone South–Brookings and Big Stone South–Ellendale MVP Projects and all revenues received from other utilities under MISO's tariffed rates as a credit in its TCR revenue requirement calculations. In doing so, the MPUC's order diverts interstate wholesale revenues that have been approved by the FERC to offset FERC-approved expenses, effectively reducing OTP's recovery of those FERC-approved expense levels. The MPUC-ordered treatment will result in the projects being treated as retail investments for Minnesota retail ratemaking purposes. Because the FERC's revenue requirements and authorized returns will vary from the MPUC revenue requirements and authorized returns for the project investments over the lives of the projects, the impact of this decision will vary over time and be dependent on the differences between the revenue requirements and returns in the two jurisdictions at any given time. On August 18, 2017 OTP filed an appeal of the MPUC order with the Minnesota Court of Appeals to contest the portion of the order requiring OTP to allocate costs between jurisdictions of the FERC MVP transmission projects in the TCR rider. OTP believes the MPUC-ordered treatment conflicts with federal authority over transmission of electricity in interstate commerce and rates for the transmission of electricity subject to the jurisdiction of the FERC as set forth in the Federal Power Act of 1935, as amended (Federal Power Act). The decision is expected in late 2018.

Environmental Cost Recovery Rider—The Minnesota ECR rider provided for recovery of OTP's Minnesota jurisdictional share of the revenue requirements of its investment in the Big Stone Plant AQCS. The ECR rider provided for a return on the project's construction work in progress (CWIP) balance at the level approved in OTP's 2010 general rate case. OTP filed its 2015 annual update on July 31, 2015, with a request to keep the 2014 annual update rate in place. On December 21, 2015 OTP filed a supplemental filing with updated financial information. The MPUC issued an order on March 9, 2016 approving OTP's request to leave the 2014 annual update rate in place. OTP filed an update to its Minnesota ECR rider on April 29, 2016 to incorporate the impact of bonus depreciation for income taxes, an adjusted rate of return on rate base and allocation factors to align with its 2016 general rate case request, with an effective date of September 1, 2016. On July 5, 2016 the MPUC issued an order approving the proposed rates on a provisional basis. On October 30, 2017 the MPUC issued an order resetting OTP's Minnesota ECR rate in effect since September 1, 2016 to refund $1.9 million previously collected under the rider, beginning November 1, 2017. In its 2016 general rate case order, the MPUC approved OTP's proposal to transition eligible rate base and expense recovery from the ECR rider to base rate recovery, effective with implementation of final rates in November 2017.

Reagent Costs and Emission Allowances—On July 31, 2014 OTP filed a request with the MPUC to revise its Fuel Clause Adjustment (FCA) rider in Minnesota to include recovery of reagent and emission allowance costs. On March 12, 2015 the MPUC denied OTP's request to revise its FCA rider to include recovery of these costs. These costs were included in OTP's 2016 general rate case in Minnesota and were considered for recovery either through the FCA rider or general rates. In its 2016 general rate case order issued May 1, 2017 the MPUC again denied OTP's request for recovery of test-year reagent costs and emission allowances in base fuel costs or through the FCA rider. Instead, the test-year costs will be recovered in general rates and variability of those costs in excess of amounts included in general rates will only be recovered to the extent actual kwh sales exceed forecasted kwh sales used to establish general rates.

Capital Structure Petition—Minnesota law requires an annual filing of a capital structure petition with the MPUC. In this filing the MPUC reviews and approves the capital structure for OTP. Once the petition is approved, OTP may issue securities without further petition or approval, provided the issuance is consistent with the purposes and amounts set forth in the approved capital structure petition. The MPUC approved OTP's most recent capital structure petition on September 1, 2017, allowing for an equity to total capitalization ratio between 47.4% and 58.0%, with total capitalization not to exceed $1,178,024,000 until the MPUC issues a new capital structure order for 2018. OTP is required to file its 2018 capital structure petition no later than May 1, 2018.

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North Dakota

OTP is subject to the jurisdiction of the NDPSC with respect to rates, services, certain issuances of securities, construction of major utility facilities and other matters. The NDPSC periodically performs audits of gas and electric utilities over which it has rate setting jurisdiction to determine the reasonableness of overall rate levels. In the past, these audits have occasionally resulted in settlement agreements adjusting rate levels for OTP.

The North Dakota Energy Conversion and Transmission Facility Siting Act grants the NDPSC the authority to approve sites in North Dakota for large electric generating facilities and high voltage transmission lines. This Act is similar to the Minnesota Power Plant Siting Act described above and applies to proposed wind energy electric power generating plants exceeding 500 kW of electricity, non-wind energy electric power generating plants exceeding 50,000 kW and transmission lines with a design in excess of 115 kV. OTP is required to submit a ten-year plan to the NDPSC biennially.

The NDPSC reserves the right to review the issuance of stocks, bonds, notes and other evidence of indebtedness of a public utility. However, the issuance by a public utility of securities registered with the SEC is expressly exempted from review by the NDPSC under North Dakota state law.

General Rates—On November 2, 2017 OTP filed a request with the NDPSC for a rate review and an effective increase in annual revenues from non-fuel base rates of $13.1 million or 8.72%. In the request, OTP proposed an allowed return on rate base of 7.97% and an allowed rate of return on equity of 10.30%. On December 20, 2017 the NDPSC approved OTP's request for interim rates to increase annual revenue collections by $12.8 million, effective January 1, 2018. OTP used a lower rate of return on equity in the calculation of interim rates based on the rate of return on equity used in its 2018 test-year rate request.

OTP's most recent general rate increase in North Dakota of $3.6 million, or approximately 3.0%, was granted by the NDPSC in an order issued on November 25, 2009 and effective December 2009. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.62%, and its allowed rate of return on equity was set at 10.75%.

Renewable Resource Adjustment—OTP has a North Dakota Renewable Resource Adjustment (NDRRA) which enables OTP to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. This rider allows OTP to recover costs associated with new renewable energy projects as they are completed, along with a return on investment. The NDPSC approved OTP's 2014 annual update to the NDRRA, including a change in rate design from an amount per kwh consumed to a percentage of a customer's bill, on March 25, 2015 with an effective date of April 1, 2015. OTP submitted its 2015 annual update to the NDRRA rider rate on December 31, 2015 with a requested implementation date of April 1, 2016. On February 25, 2016 OTP made a supplemental filing to address the impact of bonus depreciation for income taxes and related deferred tax assets on the NDRRA, as well as an adjustment to the estimated amount of Federal Production Tax Credits used. The NDPSC approved the NDRRA 2015 annual update on June 22, 2016 with an effective date of July 1, 2016. The updated NDRRA reflects a reduction in the ROE component of the rate from 10.75%, approved in OTP's most recent general rate case, to 10.50%. OTP submitted its 2016 annual update to the NDRRA rider rate on December 30, 2016, requesting a decrease to the NDRRA rate from 7.573% to 7.005%. The NDPSC approved the NDRRA 2016 annual update on March 15, 2017 with an effective date of April 1, 2017.

In conjunction with OTP's November 2, 2017 general rate case filing, OTP submitted an updated proposal to adjust the NDRRA rate to reflect updated costs and collections, as well as reflect a rate of return and capital structure level consistent with those proposed in the general rate case. The NDPSC approved the update to the NDRRA rate in conjunction with approving the rate case interim rates. The new NDRRA rate increased from 7.005% to 7.756% with an effective date of January 1, 2018.

Transmission Cost Recovery Rider—North Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. For qualifying projects, the law authorizes a current return on CWIP and a return on investment at the level approved in the utility's most recent general rate case.

On August 31, 2015 OTP filed its 2015 annual update to its North Dakota TCR rider rate requesting recovery of approximately $10.2 million for 2016 compared with $8.5 million for 2015, including costs assessed by the MISO as well as costs from the Southwest Power Pool (SPP) that OTP began incurring January 1, 2016. These costs are associated with OTP's load connected to the transmission system of Central Power Electric Cooperative (CPEC). OTP's load became subject to SPP transmission-related charges when CPEC transmission assets were added to the SPP. The NDPSC approved OTP's 2015 annual update to its TCR rider rate on December 16, 2015, with an effective date of January 1, 2016.

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On September 1, 2016 OTP filed its annual update to the TCR rider requesting a revenue requirement of $5.7 million, which includes a reduction of $2.6 million for a projected over-collection for 2016. Primary drivers of the decrease from the 2015 updated rider rate include the impact of federal bonus depreciation and unresolved MISO ROE complaint proceedings. OTP filed a supplemental filing on September 14, 2016, requesting that the over-collection balance be spread over the next two years for purposes of reducing the volatility of the rates from year to year. The NDPSC approved the update on December 14, 2016. The new rates went into effect on January 1, 2017.

On August 31, 2017 OTP filed its annual update to the TCR rider requesting a revenue requirement of $8.6 million. OTP filed a supplemental filing on November 2, 2017, reducing its revenue requirement request by $0.6 million to $8.0 million to reflect the rate of return and allocation factors used in its submitted general rate case also filed on November 2, 2017. The NDPSC approved the update for recovery of the $8.0 million revenue requirement on November 29, 2017. The new rates went into effect on January 1, 2018.

Environmental Cost Recovery Rider—OTP has an ECR rider in North Dakota to recover its North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant Mercury and Air Toxics Standards (MATS) projects. The ECR rider provides for a return on investment at the level approved in OTP's most recent general rate case and for recovery of OTP's North Dakota share of reagent and emission allowance costs.

On March 31, 2015 OTP filed its annual update to the ECR. This update included a request to increase the ECR rider rate from 7.531% to 9.193% of base rates. The NDPSC approved the annual update on June 17, 2015 with an effective date of July 1, 2015, along with the approval of recovery of OTP's North Dakota jurisdictional share of Hoot Lake Plant MATS project costs.

On March 31, 2016 OTP filed its annual update to the ECR rider requesting a reduction in the rate from 9.193% to 7.904% of base rates, or a revenue requirement reduction from $12.2 million to $10.4 million, effective July 1, 2016. The rate reduction request was primarily due to the Company's 2015 bonus depreciation election for income taxes, which reduces revenue requirements. The filing was approved on June 22, 2016.

On March 31, 2017 OTP filed its annual update to the ECR rider requesting a reduction in the rate from 7.904% to 7.633% of base rates, or a revenue requirement reduction from $10.4 million to $9.9 million, effective July 1, 2016. The rate reduction request was primarily due to a reduction in the projects' unrecovered costs and lower net book values as a result of depreciation. The filing was approved on July 12, 2017.

In conjunction with OTP's November 2, 2017 general rate case filing, OTP submitted an updated proposal to adjust the ECR rider rate to reflect updated costs and collections, as well as reflect a rate of return and capital structure level consistent with those proposed in the general rate case. The NDPSC approved the update to the ECR rider rate in conjunction with approving the general rate case interim rates. The new ECR rate decreased from 7.633% to 6.629% with an effective date of January 1, 2018.

Reagent Costs and Emission Allowances—On July 31, 2014 OTP filed a request with the NDPSC to revise its FCA rider in North Dakota to include recovery of new reagent and emission allowance costs. On February 25, 2015 the NDPSC approved recovery of these costs through modification of the ECR rider, instead of recovery through the FCA as OTP had proposed. The ECR rider reagent and emissions allowance charge became effective May 1, 2015.

South Dakota

Under the South Dakota Public Utilities Act, OTP is subject to the jurisdiction of the SDPUC with respect to rates, public utility services, construction of major utility facilities, establishment of assigned service areas and other matters. Under the South Dakota Energy Facility Permit Act, the SDPUC has the authority to approve sites in South Dakota for large energy conversion facilities (100,000 kW or more) and most transmission lines with a design of 115 kV or more.

2010 General Rate Case—OTP's most recent general rate increase in South Dakota of approximately $643,000 or approximately 2.32% was granted by the SDPUC in an order issued on April 21, 2011 and effective with bills rendered on and after June 1, 2011. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.50%.

Transmission Cost Recovery Rider—South Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. OTP has a TCR rider in South Dakota to recover its South Dakota jurisdictional share of the revenue requirements associated with its investment in new or modified electric transmission facilities. The SDPUC approved OTP's 2014 annual update on February 13, 2015 with an effective date of March 1, 2015. OTP filed its 2015 annual update on October 30, 2015 with a proposed effective date of March 1, 2016. A supplemental filing was made on February 3, 2016 to

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true-up the filing to include the impact of bonus depreciation elected for 2015, the inclusion of a deferred tax asset relating to a net operating loss and the proration of accumulated deferred income taxes. This update included the recovery of new SPP transmission costs OTP began to incur on January 1, 2016. On February 12, 2016 the SDPUC approved OTP's annual update to its TCR rider, with an effective date of March 1, 2016. On November 1, 2016 OTP filed the annual update to the South Dakota TCR rider. OTP made a supplemental filing on January 20, 2017 to include updated costs through December 2016 as well as updated forecast information. On February 17, 2017 the SDPUC approved OTP's annual update to its TCR rider, with an effective date of March 1, 2017. On November 1, 2017 OTP filed the annual update to the South Dakota TCR rider with a requested annual revenue requirement of $1.8 million and effective date of March 1, 2018. A supplemental filing was made on January 29, 2018 to reflect updated costs and collections and incorporate the impact of the reduction in the federal corporate income tax rate from 35% to 21% effective January 1, 2018. The updated revenue requirement requested is $1,778,992.

Environmental Cost Recovery Rider— OTP has an ECR rider in South Dakota to recover its South Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects. On August 31, 2015 OTP filed its annual update to the South Dakota ECR requesting recovery of approximately $2.7 million in annual revenue. The SDPUC approved the request on October 15, 2015 with an effective date of November 1, 2015. On August 31, 2016 OTP filed its 2016 update to the ECR rider, requesting recovery of approximately $2.3 million in annual revenue. The SDPUC approved the request on October 26, 2016 with an effective date of November 1, 2016. The lower revenue requirement is a result of the implementation of federal bonus depreciation taken on the Big Stone Plant AQCS. On August 31, 2017 OTP filed its 2017 update to the ECR rider, requesting recovery of approximately $2.1 million in annual revenue. The SDPUC approved the request on October 13, 2017 with an effective date of November 1, 2017.

Reagent Costs and Emission Allowances—OTP's South Dakota jurisdictional share of reagent costs and emission allowances is currently being recovered in its South Dakota FCA rider.

Energy Efficiency Plan (EEP)—The SDPUC has encouraged all investor-owned utilities in South Dakota to be part of an Energy Efficiency Partnership to significantly reduce energy use. The plan is being implemented with program costs, carrying costs and a financial incentive being recovered through an approved rider.

On May 1, 2015 OTP filed its 2014 South Dakota EEP Status Report, financial incentive and surcharge adjustment along with a request for approval of an incentive of $105,000 and EEP surcharge increase to $0.00152/kwh. On July 14, 2015 the SDPUC issued a written order approving OTP's 2014 EEP Status Report, incentive and surcharge increases.

On April 29, 2016 OTP filed its 2015 South Dakota EEP Status Report, financial incentive and surcharge adjustment with the SDPUC. The filing requested approval of an incentive of $105,900 and a decrease in the EEP surcharge from $0.00152/kwh to $0.00114/kwh effective July 1, 2016. The SDPUC approved the request. On April 29, 2016 OTP also filed its 2017-2019 goals and budgets for its South Dakota EEP triennial plan. For the 2017, 2018 and 2019 EEP planning years, OTP has proposed energy savings goals and budgets of 3,804,094 kwh and $449,000 in 2017, 3,805,177 kwh and $449,000 in 2018 and 3,806,262 kwh and $449,000 in 2019. On November 22, 2016 the SDPUC approved OTP's 2017-2019 EEP triennial plan with certain conditions.

On May 1, 2017 OTP filed its 2016 South Dakota EEP Status Report, financial incentive and surcharge adjustment with the SDPUC. The filing requested approval of an incentive of $105,900 and an increase in the EEP surcharge from $0.00114/kwh to $0.00138/kwh effective July 1, 2017. The SDPUC approved the request on June 21, 2017.

FERC

Wholesale power sales and transmission rates are subject to the jurisdiction of the FERC under the Federal Power Act. The FERC is an independent agency with jurisdiction over rates for wholesale electricity sales, transmission and sale of electric energy in interstate commerce, interconnection of facilities, and accounting policies and practices. Filed rates are effective after a one day suspension period, subject to ultimate approval by the FERC.

Multi-Value Transmission Projects—On December 16, 2010 the FERC approved the cost allocation for a new classification of projects in the MISO region called MVPs. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple transmission zones within the MISO region. The cost allocation is designed to ensure that the costs of transmission projects with regional benefits are properly assigned to those who benefit. On October 20, 2011 the FERC reaffirmed the MVP cost allocation on rehearing.

Effective January 1, 2012 the FERC authorized OTP to recover 100% of prudently incurred CWIP and Abandoned Plant Recovery on two projects approved by MISO as MVPs in MISO's 2011 Transmission Expansion Plan: the Big Stone South–Brookings MVP and the Big Stone South–Ellendale MVP.

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On November 12, 2013 a group of industrial customers and other stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff. The complainants sought to reduce the 12.38% ROE used in MISO's transmission rates to a proposed 9.15%. The complaint established a 15-month refund period from November 12, 2013 to February 11, 2015. A non-binding decision by the presiding Administrative Law Judge (ALJ) was issued on December 22, 2015 finding that the MISO transmission owners' ROE should be 10.32%, and the FERC issued an order on September 28, 2016 setting the base ROE at 10.32%. A number of parties requested rehearing of the September 2016 order and the requests are pending FERC action.

On November 6, 2014 a group of MISO transmission owners, including OTP, filed for a FERC incentive of an additional 50-basis points for Regional Transmission Organization participation (RTO Adder). On January 5, 2015 the FERC granted the request, deferring collection of the RTO Adder until the FERC issued its order in the ROE complaint proceeding. Based on the FERC adjustment to the MISO Tariff ROE resulting from the November 12, 2013 complaint and OTP's incentive rate filing, OTP's ROE will be 10.82% (a 10.32% base ROE plus the 0.5% RTO Adder) effective September 28, 2016.

On February 12, 2015 another group of stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff from 12.38% to a proposed 8.67%. This second complaint established a second 15-month refund period from February 12, 2015 to May 11, 2016. The FERC issued an order on June 18, 2015 setting the complaint for hearings before an ALJ, which were held the week of February 16, 2016. A non-binding decision by the presiding ALJ was issued on June 30, 2016 finding that the MISO transmission owners' ROE should be 9.7%. OTP is currently waiting for the issuance of a FERC order on the second complaint.

Based on the probable reduction by the FERC in the ROE component of the MISO Tariff, OTP had a $2.7 million liability on its balance sheet as of December 31, 2016, representing OTP's best estimate of the refund obligations that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on a reduced ROE. MISO processed the refund for the FERC-ordered reduction in the MISO Tariff allowed ROE for the first 15-month refund period in its February and June 2017 billings. The refund, in combination with a decision in the 2016 Minnesota general rate case that affected the Minnesota TCR rider, has resulted in a reduction in OTP's accrued MISO Tariff ROE refund liability from $2.7 million on December 31, 2016 to $1.6 million as of December 31, 2017.

In June 2014, the FERC adopted a two-step ROE methodology for electric utilities in an order issued in a complaint proceeding involving New England Transmission Owners (NETOs). The issue of how to apply the FERC ROE methodology has been contested in various complaint proceedings, including the two ROE complaints involving MISO transmission owners discussed above. In April 2017 the Court of Appeals for the District of Columbia (D.C. Circuit) vacated and remanded the FERC's June 2014 ROE order in the NETOs' complaint. The D.C. Circuit found that the FERC had not properly determined that the ROE authorized for NETOs prior to June 2014 was unjust and unreasonable. The D.C. Circuit also found that the FERC failed to justify the new ROE methodology. OTP will await the FERC response to the April 2017 action of the D.C. Circuit before determining if an adjustment to its accrued refund liability is required. On September 29, 2017 the MISO transmission owners filed a motion to dismiss the second complaint based on the D.C. Circuit decision in the NETO complaint. If the FERC were to act on a motion to dismiss, it would eliminate the refund obligation from the second complaint and the ROE from the first complaint would remain in effect.

Together with as many as 200 utilities, generators and power marketers, OTP participated in proceedings before the FERC regarding the calculation, assessment and implementation of MISO Revenue Sufficiency Guarantee (RSG) charges for entities participating in the MISO wholesale energy market since that market's start on April 1, 2005 until the conclusion of the proceedings on May 2, 2015. The proceedings fundamentally concerned MISO's application of its MISO RSG rate on file with the FERC to market participants, revisions to the RSG rate based on several FERC orders, and the FERC's decision to not resettle the markets based on MISO application of the RSG rate to market participants. Several of the FERC's orders are on review in a set of consolidated cases before the D.C. Circuit. The consolidated petitions at the D.C. Circuit involve multiple petitioners and intervenors. OTP is an intervenor in these cases. Final briefs were filed in January 2018. Oral arguments for this case are expected in the spring of 2018 with a final decision expected late in 2018. MISO has not made available past billing or resettlement data necessary for determining amounts that might be payable if the FERC's decisions are reversed. Therefore, the Company cannot estimate OTP's exposure at this time from a final order reversing the relevant FERC orders, which could have an adverse effect on the Company's results of operations.

NAEMA

OTP is a member of the North American Energy Marketers Association (NAEMA) which is an independent, non-profit trade association representing entities involved in the marketing of energy or in providing services to the energy industry. NAEMA has over 150 members with operations in 48 states and Canada. Power pool sales are conducted continuously through NAEMA in accordance with schedules filed by NAEMA with the FERC.

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North American Electric Reliability Corporation (NERC)

NERC is an international regulatory authority, subject to oversight by the FERC and governmental authorities in Canada, whose mission is to assure the reliability of the bulk power system in North America. As an owner and operator within the bulk power system, OTP is required to comply with NERC reliability standards, including standards on cybersecurity and protection of critical infrastructure.

Midwest Reliability Organization (MRO)

OTP is a member of the MRO. The MRO is a non-profit organization dedicated to ensuring the reliability and security of the bulk power system in the north central region of North America, including parts of both the United States and Canada. MRO began operations in 2005 and is one of eight regional entities in North America operating under authority from regulators in the United States and Canada through a delegation agreement with the NERC. The MRO is responsible for: (1) developing and implementing reliability standards, (2) enforcing compliance with those standards, (3) providing seasonal and long-term assessments of the bulk power system's ability to meet demand for electricity, and (4) providing an appeals and dispute resolution process.

The MRO region covers roughly one million square miles spanning the provinces of Saskatchewan and Manitoba, the states of North Dakota, Minnesota, Nebraska and the majority of territory in the states of South Dakota, Iowa and Wisconsin. The region includes more than 130 organizations that are involved in the production and delivery of power to more than 20 million people. These organizations include municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown Corporations, independent power producers and others who have interests in the reliability of the bulk power system.

To ensure our compliance with NERC standards, the MRO periodically audits OTP. OTP's most recent audit began with a notification in October 2015 and MRO audit staff conducted fieldwork in January 2016. On February 3, 2017 OTP received the final audit report from the MRO audit team. The MRO found no potential violations at OTP. OTP's next audit will take place in the first quarter of 2019.

MISO

OTP is a member of the MISO. As the transmission provider and security coordinator for the region, the MISO seeks to optimize the efficiency of the interconnected system, provide regional solutions to regional planning needs and minimize risk to reliability through its security coordination, long-term regional planning, market monitoring, scheduling and tariff administration functions. The MISO covers a broad region containing all or parts of 15 states and the Canadian province of Manitoba. The MISO has operational control of OTP's transmission facilities above 100 kV, but OTP continues to own and maintain its transmission assets.

Through the MISO Energy Markets, MISO seeks to develop options for energy supply, increase utilization of transmission assets, optimize the use of energy resources across a wider region and provide greater visibility of data. MISO aims to facilitate a more cost-effective and efficient use of the wholesale bulk electric system.

The MISO Ancillary Services Market (ASM) facilitates the provision of Regulation, Spinning Reserve and Supplemental Reserves. The ASM integrates the procurement and use of regulation and contingency reserves with the existing Energy Market. OTP has actively participated in the market since its commencement.

Other

OTP is subject to various federal laws, including the Public Utility Regulatory Policies Act of 1978 and the Energy Policy Act of 1992 (which are intended to promote the conservation of energy and the development and use of alternative energy sources) and the Energy Policy Act of 2005.

Competition, Deregulation and Legislation

Electric sales are subject to competition in some areas from municipally owned systems, rural electric cooperatives and, in certain respects, from on-site generators and

cogenerators. Electricity also competes with other forms of energy. The degree of competition may vary from time to time depending on relative costs and supplies of other forms of energy.

The Company believes OTP is well positioned to be successful in a competitive environment. A comparison of OTP's electric retail rates to the rates of other investor-owned utilities, cooperatives and municipals in the states OTP serves indicates OTP's rates are competitive.

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Legislative and regulatory activity could affect operations in the future. OTP cannot predict the timing or substance of any future legislation or regulation. The Company does not expect retail competition to come to the states of Minnesota, North Dakota or South Dakota in the foreseeable future. There has been no legislative action regarding electric retail choice in any of the states where OTP operates. The Minnesota legislature has in the past considered legislation that, if passed, would have limited the Company's ability to maintain and grow its nonelectric businesses.

OTP is unable to predict the impact on its operations resulting from future regulatory activities, from future legislation or from future taxes that may be imposed on the source or use of energy.

Environmental Regulation

Impact of Environmental Laws—OTP's existing generating plants are subject to stringent federal and state standards and regulations regarding, among other things, air, water and solid waste pollution. In the five years ended December 31, 2017 OTP invested approximately $202 million in environmental control facilities. The 2018 and 2019 construction budgets include approximately $5 million and $4 million, respectively, for environmental equipment for existing facilities.

Air Quality - Criteria Pollutants—Pursuant to the Clean Air Act (CAA), the Environmental Protection Agency (EPA) has promulgated national primary and secondary standards for certain air pollutants.

The primary fuels burned by OTP's steam generating plants are North Dakota lignite coal and western subbituminous coal. Hoot Lake Plant, Big Stone Plant, and Coyote Station are currently operating within all presently applicable federal and state air quality and emission standards.

The CAA, in addressing acid deposition, imposed requirements on power plants in an effort to reduce national emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x).

The national Acid Rain Program SO_2 emission reduction goals are achieved through a market based system under which power plants are allocated "emissions allowances" that require plants to either reduce their SO_2 emissions or acquire allowances from others to achieve compliance. Each allowance is an authorization to emit one ton of SO_2. SO_2 emission requirements are currently being met by all of OTP's generating facilities without the need to acquire additional allowances for compliance.

The national Acid Rain Program NO_x emission reduction goals are achieved by imposing mandatory emissions standards on individual sources. All of OTP's generating facilities met the NO_x standards during 2017.

The Cross-State Air Pollution Rule (CSAPR) requires SO_2 and NO_x emission reductions in primarily eastern states in order to allow downwind states to achieve national ambient air quality standards (NAAQS). CSAPR's Phase 1 emission budgets began on January 1, 2015 for the annual SO_2 and NO_x programs, with stricter Phase 2 budgets beginning in 2017.

The CSAPR rule applies to OTP's Solway gas peaking plant and the Hoot Lake coal-fired plant in Minnesota. Minnesota is considered a Group 2 state for SO_2 compliance. Any SO_2 allowances that need to be obtained for Hoot Lake Plant will need to be from an entity in a Group 2 state. The impact of the CSAPR rule is anticipated to be minimal due to the sharp decline in Group 2 SO_2 allowance prices since 2016 and reduced dispatch of Hoot Lake Plant.

On September 7, 2016 the EPA finalized an update to the CSAPR to address interstate emission transport with respect to the more recent 2008 ozone NAAQS. The updated CSAPR does not apply to Minnesota, North Dakota and South Dakota.

On October 1, 2015 the EPA announced that it tightened the primary and secondary NAAQS for ozone from 75 parts per billion (ppb) to 70 ppb. This was at the upper end of the range of which the EPA had proposed, which was 65 to 70 ppb. On November 16, 2017 EPA issued a final rule determining that all of the areas in the states in which OTP operates will be designated as attainment/unclassifiable.

In June 2010, the EPA established a new primary NAAQS for SO_2 at a level of 75 ppb on a 1-hour average. Designations for this standard are proceeding under several different pathways. For certain large sources as defined by 2012 emissions, including Big Stone Plant and Coyote Station, the EPA entered into a consent decree with the Sierra Club/Natural Resources Defense Council that required the EPA to promulgate final designations near those sources by July 2, 2016. On June 30, 2016, the EPA signed a final rule that designated the areas around Big Stone Plant and Coyote Station as being in attainment/unclassifiable with the 1-hour SO_2 NAAQS. Numerous other sources, including Hoot Lake Plant, are covered by the EPA's final Data Requirements Rule (DRR) that was finalized in August 2015. The DRR requires states to provide either modeling or monitoring data to adequately characterize SO_2 emissions surrounding those sources. Based on modeling, in January 2018, the EPA published a final determination of attainment/unclassifiable for the county in which Hoot Lake Plant resides.

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Air Quality – Hazardous Air Pollutants—On December 16, 2011 the EPA signed a final rule to reduce mercury and other air toxics emissions from power plants known as the MATS rule. With the installation of new pollution control equipment in 2015, OTP's affected units are meeting current requirements. Emissions monitoring equipment and/or stack testing is being used to verify compliance with the standards. Litigation surrounding the MATS rule is ongoing despite the expiration of the compliance deadlines, and the rule remains in effect while the litigation continues. On April 15, 2016 the EPA issued a supplemental finding that the MATS rule continues to be "appropriate and necessary" when considering the costs of compliance. Litigation surrounding this finding is being held in abeyance while EPA considers whether it should be maintained, modified or otherwise reconsidered.

Air Quality – EPA New Source Review Enforcement Initiative—In 1998 the EPA announced its New Source Review Enforcement Initiative targeting coal-fired power plants, petroleum refineries, pulp and paper mills and other industries for alleged violations of the EPA's New Source Review rules. These rules require owners or operators that construct new major sources or make major modifications to existing sources to obtain permits and install air pollution control equipment at affected facilities. Pursuant to the

Initiative, the EPA has attempted to determine if emission sources violated certain provisions of the CAA by making major modifications to their facilities without installing state-of-the-art pollution controls. OTP has not received any recent requests from the EPA, pursuant to Section 114(a) of the CAA, to provide information relative to past operation and capital construction projects at its coal-fired plants.

Air Quality – Regional Haze Program— The Regional Haze Rule requires emissions reductions from certain sources that are deemed to contribute to visibility impairment in Class I air quality areas. Based on the South Dakota Department of Environment and Natural Resources' determination and the final South Dakota Regional Haze State Implementation Plan approved by the EPA on March 29, 2012, Big Stone Plant was required to install Selective Catalytic Reduction and separated over-fire air to reduce NO_x emissions, dry flue gas desulfurization to reduce SO_2 emissions, and a new baghouse for particulate matter control. The Big Stone Plant compliant AQCS equipment was placed into commercial operation on December 29, 2015.

The North Dakota Regional Haze State Implementation Plan requires that Coyote Station reduce its NO_x emissions to 0.5 pounds per million Btu as calculated on a 30-day rolling average basis beginning on July 1, 2018. The control equipment was installed during a spring 2016 outage.

Air Quality – Greenhouse Gas (GHG) Regulation—Combustion of fossil fuels for the generation of electricity is a considerable stationary source of CO_2 emissions in the United States and globally. OTP is an owner or part-owner of three baseload, coal-fired electricity generating plants and three fuel-oil or natural gas-fired combustion turbine peaking plants with a combined net dependable capacity of 650 MW. In 2017 these plants emitted approximately 2.9 million tons of CO_2.

In April 2007, the U.S. Supreme Court issued a decision that determined that the EPA has authority to regulate CO_2 and other GHGs from automobiles as "air pollutants" under the CAA. The EPA thereafter conducted a rulemaking to determine whether GHG emissions contribute to climate change "which may reasonably be anticipated to endanger public health or welfare." While this case addressed a provision of the CAA related to emissions from motor vehicles, a parallel provision of the CAA applies to stationary sources such as electric generators. The EPA determined that parallel provision would be automatically triggered once the EPA began regulating motor vehicle GHG emissions. The first step in the EPA rulemaking process was the publication of an endangerment finding in the December 15, 2009 Federal Register where the EPA found that CO_2 and five other GHGs – methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride (SF_6) – threaten public health and the environment.

The EPA's endangerment finding for GHGs did not in and of itself impose any emission reduction requirements but rather authorized the EPA to finalize the GHG standards for new light-duty vehicles as part of the joint rulemaking with the Department of Transportation. These standards applied to motor vehicles as of January 2011, which the EPA determined made GHGs "subject to regulation" under the CAA. According to the EPA, this triggered the Prevention of Significant Deterioration (PSD) and Title V operating permits programs for stationary sources of GHGs.

On June 6, 2010 the EPA published a final "tailoring rule" that phased in application of its PSD and Title V programs to GHG emission sources, including power plants. The PSD program applies to existing sources if there is a physical change or change in the method of operation of the facility that results in a significant net emissions increase of any pollutant. As a result, PSD does not apply on a set timeline as is the case with other regulatory programs, but is triggered when certain activities take place at a major source. If triggered, the owner or operator of an affected facility must undergo a review which requires, among other things, the identification and implementation of best-available control technology (BACT) for the regulated air pollutants for which there is a significant net emissions increase, and an analysis of the ambient air quality impacts of the facility.

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In June 2012 the United States Court of Appeals for the D.C. Circuit upheld most of the EPA's rules regarding the regulation of GHGs under the CAA, including the tailoring rule. However, in October 2013 the U.S. Supreme Court granted a petition for a writ of certiorari to review the question of whether the regulation of new motor vehicle GHG emissions does in fact automatically trigger PSD and Title V regulation of GHGs for stationary sources. On June 23, 2014 the U.S. Supreme Court issued its decision that, in summary, held the EPA exceeded its statutory authority and may not require a PSD or Title V permit based solely on GHG emissions. However, the U.S. Supreme Court also said the EPA could continue to require that PSD permits for sources otherwise subject to PSD based on emissions of conventional pollutants contain limitations on GHG emissions based on the application of BACT. The EPA revised its regulations to implement this ruling and in 2016 proposed a *de minimis* level of GHG emissions below which PSD would not apply. OTP does not anticipate making modifications that would trigger PSD requirements at any of its facilities or undertaking construction of a new unit that might trigger PSD.

The EPA has developed New Source Performance Standards (NSPS) for GHGs from new and existing fossil fuel-fired electric generating units. On October 23, 2015 the EPA published the final NSPS under section 111(b) of the CAA that requires certain new units (as well as modified and reconstructed units) to meet CO_2 emission standards. New natural gas combustion turbines are required to meet a standard of 1,000 lbs. of CO_2 per gross megawatt hour averaged over a 12-month period if they meet the definition of a baseload unit. New natural gas combined cycle units are anticipated to fit into this category. Simple cycle combustion turbines are regulated in a non-baseload category that is required to meet a heat input based standard that can be met by burning clean fuels such as natural gas. This rule was challenged by a number of parties and litigation is pending. Therefore, there is uncertainty regarding the future of the NSPS rules.

GHG performance standards for existing sources are being developed under CAA Section 111(d) (111(d) Standard). A 111(d) Standard, unlike those set under CAA Section 111(b), applies to existing sources of a pollutant. Under Section 111(d), the EPA promulgates emission guidelines and the states are then given a period of time to develop plans to implement the standard. The EPA reviews each state-developed standard and then approves it if the state's plan comports with the federal emission guidelines. If the state does not submit a plan or the EPA finds that the plan is inadequate, the EPA will prescribe a plan for that state.

For both new and existing sources, the EPA must develop a "standard of performance," which is defined as:

> …a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the [EPA] Administrator determines has been adequately demonstrated.

For existing sources, Section 111(d) also requires the EPA to consider, "among other factors, remaining useful lives of the sources in the category of sources to which such standard applies."

On October 23, 2015 the EPA published final Section 111(d) emission guidelines for existing fossil fuel-fired power plants, termed the Clean Power Plan (CPP). The final rule used a formula to calculate state goals that relied on three building blocks: (1) a heat rate improvement at each coal plant, (2) increased reliance on natural gas combined cycle units, and (3) increased deployment of renewable energy. These building blocks were applied to each grid interconnection that resulted in final national uniform emission rate standards of 1,305 pounds of CO_2 per net megawatt hour for coal plants and 771 pounds of CO_2 per net megawatt hour for natural gas combined cycle plants. The EPA then translated the rate goals into mass-based goals that can be applied to existing sources or, if a state chooses, a mass-based goal that applies to both existing sources and new sources.

A number of states, utilities, and trade groups filed petitions for review with the D.C. Circuit seeking to overturn the rule, and also moved to stay the rule. On January 14, 2016 the D.C. Circuit denied the stay motions. Numerous petitioners then sought an emergency stay in the U.S. Supreme Court. On February 9, 2016 the U.S. Supreme Court granted a stay of the CPP, pending disposition of petitions for review in the D.C. Circuit. The D.C. Circuit heard oral argument on challenges to the CPP on September 27, 2016 before the full court, and a decision was expected in the first half of 2017. However, pursuant to Executive Order 13783, Promoting Energy Independence and Economic Growth, the EPA was directed to consider suspending, revising or rescinding the CO_2 rules discussed above. Thereafter, the EPA issued notices of its intent to review these rules pursuant to the Executive Order, and it filed motions to stay the pending litigation. The D.C. Circuit subsequently issued orders holding in abeyance the appeals of both the NSPS and the CPP, pending EPA review. On October 16, 2017 the EPA published a proposed rule to repeal the CPP, and on December 18, 2017, the EPA announced an Advance Notice of Proposed Rulemaking to solicit information in order to inform the EPA as the Agency considers proposing a future 111(d) rule that is consistent with the legal interpretation discussed in the proposed repeal rule. Therefore, there is uncertainty regarding the future of regulation of CO_2 under Section 111(d).

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Several states and regional organizations have or will develop state-specific or regional legislative initiatives to reduce GHG emissions through mandatory programs. In 2007 the state of Minnesota passed legislation regarding renewable energy portfolio standards that requires retail electricity providers to obtain 25% of the electric energy sold to Minnesota customers from renewable sources by the year 2025. Additionally, in 2013 the state of Minnesota passed a provision that requires public utilities to generate or procure sufficient electricity generated by solar energy to serve its retail electricity customers in Minnesota so that by the end of 2020, at least 1.5% of the utility's total retail electric sales to retail customers in Minnesota is generated by solar energy. The Minnesota legislature set a January 1, 2008 deadline for the MPUC to establish an estimate of the likely range of costs of future CO_2 regulation on electricity generation. The legislation also set state targets for reducing fossil fuel use, included goals for reducing the state's output of GHGs, and restricted importing electricity that would contribute to statewide power sector CO_2 emission. The MPUC, in its order dated December 21, 2007, established an estimate of future CO_2 regulation costs at between $4.00 per ton and $30.00 per ton emitted in 2012 and after. Annual updates of the range are required. For 2017 the range is $9.05 to $43.06 per ton, and the applicable effective date to begin using CO_2 costs in resource planning decisions is 2020. The MNDOC and MPCA have proposed a range of $5.00 to $25.00 per ton beginning in 2025 to be used for 2018.

In 2013, Minnesota opened a new docket to investigate the environmental and socioeconomic costs of externalities associated with electricity generation. This docket studied the impact of CO_2 and certain criteria pollutants. A final order was issued on January 3, 2018. The environmental cost values for CO_2 range from a low of $8.44 per ton and a high of $39.76 per ton in 2017 to a low of $15.20 per ton and a high of $69.48 per ton in 2050. Low, medium, and high values were also set for various criteria pollutants for rural, metropolitan fringe, and urban areas in the state.

The states of North Dakota and South Dakota currently have no proposed or pending legislation related to the regulation of GHG emissions, but North Dakota and South Dakota have 10% renewable energy objectives. OTP currently has sufficient renewable generation to meet the renewable energy objectives in both North Dakota and South Dakota.

While the eventual outcome of GHG regulation is unknown, OTP is taking steps to reduce its carbon footprint and mitigate levels of CO_2 emitted in the process of generating electricity for its customers through the following initiatives:

- Supply efficiency and reliability: Since 2005, SO_2, NO_x and mercury emitted from OTP's fossil fuel-fired plants have decreased 55%, 77% and 83%, respectively. OTP's efforts to increase plant efficiency and add renewable energy to its resource mix have reduced its CO_2 intensity. Between 2005 and 2017 OTP decreased its overall system average CO_2 emissions intensity by approximately 26%. Further reductions are expected with the anticipated replacement of Hoot Lake Plant generation with natural gas-fired generation in the 2021 timeframe.

- Conservation: Since 1992 OTP has helped its customers conserve more than 4.3 million cumulative megawatt-hours of electricity, which is roughly equivalent to the amount of electricity that 358,000 average homes would use in a year and represents approximately 352% of the annual energy sales of OTP's entire residential customer base. Additionally, OTP's conservation programs contribute 113 MW of load reduction to its system.

- Renewable energy: Since 2002, OTP's customers have been able to purchase 100% of their electricity from wind generation through OTP's Tail Winds program. OTP has access to 102.9 MW of wind powered generation under power purchase agreements and owns 138 MW of wind powered generation. OTP is exploring options for meeting a Minnesota legislative mandate requiring Minnesota's investor-owned utilities to serve 1.5% of their Minnesota retail electric sales with solar power by 2020.

- Other: OTP is a participating member of the EPA's SF_6 Emission Reduction Partnership for Electric Power Systems program, which proactively is targeting a reduction in emissions of SF_6, a potent GHG. SF_6 has a global-warming potential 23,900 times that of CO_2. OTP participates in carbon sequestration research through the Plains CO_2 Reduction Partnership through the University of North Dakota's Energy and Environmental Research Center. This Partnership is a collaborative effort of approximately 100 public and private sector stakeholders working toward a better understanding of the technical and economic feasibility of capturing and storing anthropogenic CO_2 emissions from stationary sources in central North America.

While the future financial impact of any proposed or pending litigation or regulation of GHG emissions is unknown at this time, any capital and operating costs incurred for additional pollution control equipment or CO_2 emission reduction measures, such as the cost of sequestration or purchasing allowances, or offset credits, or the imposition of a carbon tax or cap and trade program at the state or federal level could materially adversely affect the Company's future results of operations, cash flows, and possibly financial condition, unless such costs could be recovered through regulated rates and/or future market prices for energy.

Water Quality—The Federal Water Pollution Control Act Amendments of 1972 and amendments thereto, provide for, among other things, the imposition of effluent limitations to regulate discharges of pollutants, including thermal discharges, into the waters of the United States, and the EPA has established effluent guidelines for the steam electric power generating industry. Discharges must also comply with state water quality standards.

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Effluent limits specific to Hoot Lake Plant and Coyote Station are incorporated into their National Pollutant Discharge Elimination System (NPDES) permits. Big Stone Plant is a zero discharge facility and therefore does not have a NPDES permit. On November 3, 2015 the EPA published the final rule that sets technology-based effluent limitations on certain types of discharges. Generally, the final rule establishes new requirements for wastewater streams from wet flue gas desulfurization, fly ash transport, and bottom ash transport. This includes zero discharge requirements for fly ash and bottom ash transport water. OTP's facilities either utilize dry ash handling or use transport water in a closed loop manner. Therefore, OTP anticipates minimal impact from the rule.

On May 9, 2014 the EPA Administrator signed a final rule implementing Section 316(b) of the Clean Water Act establishing standards for cooling water intake structures for certain existing facilities. The final rule includes seven compliance options, plus a potential "*de minimis*" option that is not well defined. Although the impact of the Hoot Lake Plant intake structure has been extensively evaluated in two separate studies both of which showed minimal impact, OTP will need to have state agency discussions during the renewal of the Hoot Lake Plant NPDES permit to determine the appropriate path forward. Coyote Station provided various studies with their next NPDES permit renewal application, but minimal impact is anticipated since Coyote Station already uses closed-cycle cooling.

OTP has all federal and state water permits presently necessary for the operation of the Coyote Station, the Big Stone Plant and the Hoot Lake Plant.

OTP owns five small dams on the Otter Tail River, which are subject to FERC licensing requirements. A license for all five dams was issued on December 5, 1991. In June 2015 OTP notified the FERC of its intent to relicense these dams. The current FERC license expires in 2021 and the licensing process takes approximately 5 years. The FERC completed the scoping meeting in the fall of 2016 and issued a study plan determination in April 2017. OTP completed the first round of studies in 2017 and will complete the second round in 2018. These studies will be followed by the filing of the license application in 2019. OTP expects the FERC to issue an order on the license application in 2021. Total nameplate rating (manufacturer's expected output) of the five dams is 3,250 kW.

Solid Waste—Permits for disposal of ash and other solid wastes have been issued for the Coyote Station, the Big Stone Plant and the Hoot Lake Plant.

On December 19, 2014 the EPA announced a final rule regulating coal combustion residuals (CCR) under the Resource Conservation and Recovery Act regulating the disposal of coal ash generated from the combustion of coal by electric utilities under Subtitle D's nonhazardous provisions. The final rule was published on April 17, 2015. The rule requires OTP to complete certain actions, such as installing additional groundwater monitoring wells and investigating whether existing surface impoundments meet defined location restrictions, in order to determine whether existing surface impoundments should be retired or retrofitted with liners. The Big Stone Plant and Coyote Station surface impoundments are currently planned to be replaced with new ash handling technology in 2018 and 2019. Existing landfill cells can continue to operate as designed, but future expansions may require composite liner and leachate collection systems. On December 20, 2016 the Water Infrastructure Improvements for the Nation (WIIN) Act was signed into law. The WIIN Act allows states to regulate CCR if the state standards are at least as protective as the EPA CCR Rule. North Dakota and South Dakota have indicated they plan to incorporate the CCR rule, but that it will take a multi-year process.

At the request of the MPCA, OTP had an ongoing investigation at its former, closed Hoot Lake Plant ash disposal sites. The MPCA continues to monitor site activities under its Voluntary Investigation and Cleanup Program. OTP completed projects in 2014 through 2017 that removed the ash in its entirety from all four Voluntary Investigation and Cleanup Program areas and placed it in OTP's permitted disposal area.

In 1980 the United States enacted the Comprehensive Environmental Response, Compensation and Liability Act, commonly known as CERCLA or the Federal Superfund law, which was reauthorized and amended in 1986. In 1983 Minnesota adopted the Minnesota Environmental Response and Liability Act, commonly known as the Minnesota Superfund law. In 1988 South Dakota enacted the Regulated Substance Discharges Act, commonly known as the South Dakota Superfund law. In 1989, North Dakota enacted the Environmental Emergency Cost Recovery Act. Among other requirements, the federal and state acts establish environmental response funds to pay for remedial actions associated with the release or threatened release of certain regulated substances into the environment. These federal and state Superfund laws also establish liability for cleanup costs and damage to the environment resulting from such release or threatened release of regulated substances. The Minnesota Superfund law also creates liability for personal injury and economic loss under certain circumstances. OTP has not incurred any significant costs to date related to these laws. OTP is not presently named as a potentially responsible party under the federal or state Superfund laws.

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Capital Expenditures

OTP is continually expanding, replacing and improving its electric facilities. During 2017 approximately $119 million in cash was invested for additions and replacements to its electric utility properties. During the five years ended December 31, 2017 gross electric property additions, including construction work in progress, were approximately $699 million and gross retirements were approximately $84 million. OTP estimates that during the five-year period 2018-2022 it will invest approximately $901 million for electric construction, including:

- $302 million for renewable wind and solar energy generation projects.
- $161 million for natural gas-fired generation to replace Hoot Lake Plant capacity.
- $136 million for numerous potential technology and infrastructure projects to transform future operations, including automated metering, telecommunications, geographic information systems, work and asset management systems, financial information systems, system infrastructure reliability improvements, outage management systems, and storage projects.
- $35 million for OTP's Big Stone South–Ellendale 345 kV transmission line project.

The remainder of the 2018-2022 anticipated capital expenditures is for asset replacements, additions and improvements across OTP's generation, transmission, distribution and general plant. See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Requirements" section for further discussion.

Franchises

At December 31, 2017 OTP had franchises to operate as an electric utility in substantially all of the incorporated municipalities it serves. All franchises are nonexclusive and generally were obtained for 20-year terms, with varying expiration dates. No franchises are required to serve unincorporated communities in any of the three states that OTP serves. OTP believes that its franchises will be renewed prior to expiration.

Employees

At December 31, 2017 OTP had 668 equivalent full-time employees. A total of 390 OTP employees are represented by local unions of the International Brotherhood of Electrical Workers under two separate contracts expiring on August 31, 2020 and October 31, 2020. OTP has not experienced any strike, work stoppage or strike vote, and considers its present relations with employees to be good.

MANUFACTURING

General

Manufacturing consists of businesses engaged in the following activities: contract machining, metal parts stamping, fabrication and painting, and production of plastic

thermoformed horticultural containers, life science and industrial packaging, and material handling components.

The Company derived 27%, 28% and 28% of its consolidated operating revenues and 11%, 11% and 9% of its consolidated operating income from the Manufacturing segment for the years ended December 31, 2017, 2016 and 2015, respectively. Following is a brief description of each of these businesses:

BTD Manufacturing, Inc. (BTD), with headquarters located in Detroit Lakes, Minnesota, is a metal stamping and tool and die manufacturer that provides its services mainly to customers in the Midwest. BTD stamps, fabricates, welds, paints and laser cuts metal components according to manufacturers' specifications primarily for the recreational vehicle, agricultural, oil and gas, lawn and garden, industrial equipment, health and fitness and enclosure industries in its facilities in Detroit Lakes and Lakeville, Minnesota, Washington, Illinois and Dawsonville, Georgia. BTD's Illinois facility also manufactures and fabricates parts for off-road equipment, mining machinery, oil fields and offshore oil rigs, wind industry components, broadcast antennae and farm equipment. BTD-Georgia offers a wide range of metal fabrication services ranging from simple laser cutting services and high volume stamping to complex weldments and assemblies for metal fabrication buyers and original equipment manufacturers.

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T.O. Plastics, Inc. (T.O. Plastics), located in Otsego and Clearwater, Minnesota, manufactures and sells thermoformed products for the horticulture industry throughout the United States. T.O. Plastics also designs and manufactures quality thermoformed products and packaging solutions for the medical and life sciences, industrial, recreation and electronics industries. Examples of products produced for these industries are clamshell packing, blister packs, returnable pallets and handling trays for shipping and storing odd-shaped or difficult-to-handle parts.

Product Distribution

The principal method for distribution of the manufacturing companies' products is by direct shipment to the customer by common carrier ground transportation. No single customer or product of the Company's manufacturing companies accounted for 10% of the Company's consolidated revenue. However, two customers combined accounted for 36% of the 2017 revenue of the Manufacturing segment.

Competition

The various markets in which the Manufacturing segment entities compete are characterized by intense competition from both foreign and domestic manufacturers. These markets have many established manufacturers with broader product lines, greater distribution capabilities, greater capital resources, excess capacity, labor advantages and larger marketing, research and development staffs and facilities than the Company's manufacturing entities.

The Company believes the principal competitive factors in its Manufacturing segment are product performance, quality, price, technical innovation, cost effectiveness, customer service and breadth of product line. The Company's manufacturing entities intend to continue to compete on the basis of high-performance products, innovative production technologies, cost-effective manufacturing techniques, close customer relations and support, and increasing product offerings.

Raw Materials Supply

The companies in the Manufacturing segment use raw materials in the products they manufacture, including steel, aluminum and polystyrene and other plastics resins. Both pricing increases and availability of these raw materials are concerns of companies in the Manufacturing segment. The companies in the Manufacturing segment attempt to pass increases in the costs of these raw materials on to their customers. Increases in the costs of raw materials that cannot be passed on to customers could have a negative effect on profit margins in the Manufacturing segment. Additionally, a certain amount of residual material (scrap) is a by-product of many of the manufacturing and production processes used by the Company's manufacturing companies. Declines in commodity prices for these scrap materials due to weakened demand or excess supply can negatively impact the profitability of the Company's manufacturing companies as it reduces their ability to mitigate the cost associated with excess material.

Backlog

The Manufacturing segment has backlog in place to support 2018 revenues of approximately $166 million compared with $118 million one year ago.

Capital Expenditures

Capital expenditures in the Manufacturing segment typically include additional investments in new manufacturing equipment or expenditures to replace worn-out manufacturing equipment. Capital expenditures may also be made for the purchase of land and buildings for plant expansion and for investments in management information systems. During 2017, cash expenditures for capital additions in the Manufacturing segment were approximately $10 million. Total capital expenditures for the Manufacturing segment during the five-year period 2018-2022 are estimated to be approximately $53 million.

Employees

At December 31, 2017 the Manufacturing segment had 1,229 full-time employees. There were 1,092 full-time employees at BTD and 137 full-time employees at T.O. Plastics as of December 31, 2017.

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PLASTICS

General

Plastics consists of businesses producing PVC pipe at plants in North Dakota and Arizona. The Company derived 22%, 19% and 20% of its consolidated operating revenues and 24%, 16% and 19% of its consolidated operating income from the Plastics segment for the years ended December 31, 2017, 2016 and 2015, respectively. Following is a brief description of these businesses:

Northern Pipe Products, Inc. (Northern Pipe), located in Fargo, North Dakota, manufactures and sells PVC pipe for municipal water, rural water, wastewater, storm drainage systems and other uses in the northern, midwestern, south-central and western regions of the United States as well as central and western Canada.

Vinyltech Corporation (Vinyltech), located in Phoenix, Arizona, manufactures and sells PVC pipe for municipal water, wastewater, water reclamation systems and other uses in the western, northwestern and south-central regions of the United States.

Together these companies have the current capacity to produce approximately 300 million pounds of PVC pipe annually.

Customers

PVC pipe products are marketed through a combination of independent sales representatives, company salespersons and customer service representatives. Customers for the PVC pipe products consist primarily of wholesalers and distributors throughout the northern, midwestern, south-central, western and northwest United States. The principal method for distribution of the PVC pipe companies' products is by common carrier ground transportation. No single customer of the PVC pipe companies accounts for over 10% of the Company's consolidated revenue. However, two customers combined accounted for 38% of the 2017 revenue of the Plastics segment.

Competition

The plastic pipe industry is fragmented and competitive due to the number of producers, the small number of raw material suppliers and the fungible nature of the product. Due to shipping costs, competition is usually regional, instead of national, in scope. The principal factors of competition are price, service, warranty, and product performance. Northern Pipe and Vinyltech compete not only against other plastic pipe manufacturers, but also ductile iron, steel and concrete pipe producers. Pricing pressure will continue to affect our Plastics segment operating margins in the future.

Northern Pipe and Vinyltech intend to continue to compete on the basis of their high quality products, cost-effective production techniques and close customer relations and support.

Manufacturing and Resin Supply

PVC pipe is manufactured through a process known as extrusion. During the production process, PVC compound (a dry powder-like substance) is introduced into an extrusion machine, where it is heated to a molten state and then forced through a sizing apparatus to produce the pipe. The newly extruded pipe is then pulled through a series of water cooling tanks, marked to identify the type of pipe and cut to finished lengths. Warehouse and outdoor storage facilities are used to store the finished product. Inventory is shipped from storage to distributors and customers by common carrier.

The PVC resins are acquired in bulk and shipped to point of use by rail car. There are four vendors that Northern Pipe and Vinyltech can source to supply their PVC resin requirements. Two vendors provided 100% of total resin purchases in 2017 and 2016. The supply of PVC resin may also be limited primarily due to manufacturing capacity and the limited availability of raw material components. A majority of U.S. resin production plants are located in the Gulf Coast region, which is subject to risk of damage to the plants and potential shutdown of resin production because of exposure to hurricanes that occur in that part of the United States. The loss of a key vendor, or any interruption or delay in the supply of PVC resin, could disrupt the ability of the Plastics segment to manufacture products, cause customers to cancel orders or require incurrence of additional expenses to obtain PVC resin from alternative sources, if such sources were available. Both Northern Pipe and Vinyltech believe they have good relationships with their key raw material vendors.

Due to the commodity nature of PVC resin and PVC pipe and the dynamic supply and demand factors worldwide, historically the markets for both PVC resin and PVC pipe have been very cyclical with significant fluctuations in prices and gross margins.

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Capital Expenditures

Capital expenditures in the Plastics segment typically include investments in extrusion machines and support equipment. During 2017, cash expenditures for capital additions in the Plastics segment were approximately $4 million. Total capital expenditures for the five-year period 2018-2022 are estimated to be approximately $19 million to replace existing equipment.

Employees

At December 31, 2017 the Plastics segment had 161 full-time employees. Northern Pipe had 95 full-time employees and Vinyltech had 66 full-time employees as of December 31, 2017.

Item 1A. RISK FACTORS

RISK FACTORS AND CAUTIONARY STATEMENTS

Our businesses are subject to various risks and uncertainties. Any of the risks described below or elsewhere in this Annual Report on Form 10-K or in our other SEC filings could materially adversely affect our business, financial condition and results of operations.

GENERAL

Federal and state environmental regulation could require us to incur substantial capital expenditures and increased operating costs.

We are subject to federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources and health safety. These laws and regulations regulate the modification and operation of existing facilities, the construction and operation of new facilities and the proper storage, handling, cleanup and disposal of hazardous waste and toxic substances. Compliance with these legal requirements requires us to commit significant resources and funds toward environmental monitoring, installation and operation of pollution control equipment, payment of emission fees and securing environmental permits. Obtaining environmental permits can entail significant expense and cause substantial construction delays. Failure to comply with environmental laws and regulations, even if caused by factors beyond our control, may result in civil or criminal liabilities, penalties and fines.

Existing environmental laws or regulations may be revised and new laws or regulations may be adopted or become applicable to us. Revised or additional regulations, which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material effect on our results of operations.

Volatile financial markets and changes in our debt ratings could restrict our ability to access capital and increase borrowing costs and pension plan and postretirement health care expenses.

We rely on access to both short- and long-term capital markets as a source of liquidity for capital requirements not satisfied by cash flows from operations. If we are unable to

access capital at competitive rates, our ability to implement our business plans may be adversely affected. Market disruptions or a downgrade of our credit ratings may increase the cost of borrowing or adversely affect our ability to access one or more financial markets.

Disruptions, uncertainty or volatility in the financial markets can also adversely impact our results of operations, the ability of customers to finance purchases of goods and services, and our financial condition, as well as exert downward pressure on stock prices and/or limit our ability to sustain our current common stock dividend level.

Changes in the U.S. capital markets could also have significant effects on our pension plan. Our pension income or expense is affected by factors including the market performance of the assets in the master pension trust maintained for the pension plan for some of our employees, the weighted average asset allocation and long-term rate of return of our pension plan assets, the discount rate used to determine the service and interest cost components of our net periodic pension cost and assumed rates of increase in our employees' future compensation. If our pension plan assets do not achieve positive rates of return, or if our estimates and assumed rates are not accurate, our earnings may decrease because net periodic pension costs would rise and we could be required to provide additional funds to cover our obligations to employees under the pension plan.

We could be required to contribute additional capital to the pension plan in the future if the market value of pension plan assets significantly declines, plan assets do not earn in line with our long-term rate of return assumptions or relief under the Pension Protection Act is no longer granted.

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Any significant impairment of our goodwill would cause a decrease in our asset values and a reduction in our net operating income.

We had approximately $37.6 million of goodwill recorded on our consolidated balance sheet as of December 31, 2017. We have recorded goodwill for businesses in our Manufacturing and Plastics business segments. If we make changes in our business strategy or if market or other conditions adversely affect operations in any of these businesses, we may be forced to record an impairment charge, which would lead to decreased assets and a reduction in net operating performance. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying amount of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including changes in economic, industry or market conditions, changes in business operations, future business operating performance, changes in competition or changes in technologies. Any changes in key assumptions or actual performance compared with key assumptions about our business and its future prospects or other assumptions could affect the fair value of one or more business segments, which may result in an impairment charge. Declines in projected operating cash flows at BTD or the Plastics segment may result in goodwill impairments that could adversely affect our results of operations and financial position, as well as financing agreement covenants.

The inability of our subsidiaries to provide sufficient earnings and cash flows to allow us to meet our financial obligations and debt covenants and pay dividends to our shareholders could have an adverse effect on the Company.

Otter Tail Corporation is a holding company with no significant operations of its own. The primary source of funds for payment of our financial obligations and dividends to our shareholders is from cash provided by our subsidiary companies. Our ability to meet our financial obligations and pay dividends on our common stock principally depends on the actual and projected earnings, cash flows, capital requirements and general financial position of our subsidiary companies, as well as regulatory factors, financial covenants, general business conditions and other matters.

Under our $130 million revolving credit agreement we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00. OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 under its $170 million revolving credit agreement. Both credit agreements contain restrictions on the payment of cash dividends on a default or event of default. As of December 31, 2017 we were in compliance with the debt covenants.

Under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. What constitutes "funds properly included in a capital account" is undefined in the Federal Power Act or the related regulations; however, the FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials. The MPUC indirectly limits the amount of dividends OTP can pay to us by requiring an equity-to-total-capitalization ratio between 47.4% and 58.0% based on OTP's 2017 capital structure petition. OTP's equity-to-total-capitalization ratio, including short-term debt, was 48.6% as of December 31, 2017.

While these restrictions are not expected to affect our ability to pay dividends at the current level in the foreseeable future, there is no assurance that adverse financial results would not reduce or eliminate our ability to pay dividends.

We rely on our information systems to conduct our business, and failure to protect these systems against security breaches or cyber-attacks could adversely affect our business and results of operations. Additionally, if these systems fail or become unavailable for any significant period of time, our business could be harmed.

All of our businesses require us to collect and maintain sensitive customer data, as well as confidential employee and shareholder information, which is subject to electronic theft or loss. We also use third-party vendors to electronically process certain of our business transactions. The efficient operation of our business is dependent on computer hardware and software systems. Information systems, both ours and those of third-parties, are vulnerable to security breach by computer hackers and cyber terrorists.

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The breach of certain business systems could affect our ability to correctly record, process and report financial information and transactions. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to our reputation. In addition, the misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant breach notification expenses and mitigation expenses such as credit monitoring. We have cybersecurity insurance related to a breach event covering expenses for notification, credit monitoring, investigation, crisis management, public relations and legal advice. The policy also provides coverage for regulatory action defense including fines and penalties, potential payment card industry fines and penalties and costs related to cyber extortion. We also maintain property and casualty insurance that may cover restoration of data, certain physical damage or third-party injuries caused by potential cybersecurity incidents. However, damage and claims arising from such incidents may not be covered or may exceed the amount of any insurance available.

We rely on industry accepted security measures and technology to securely maintain confidential and proprietary information maintained on our information systems. In an effort to reduce the likelihood and severity of cyber intrusions, we have cybersecurity processes and controls designed to protect and preserve the confidentiality, integrity and availability of data and systems. However, all these measures and technology may not adequately prevent security breaches or cyber-attacks. In addition, the unavailability of the information systems or failure of these systems to perform as anticipated for any reason could disrupt our business and could result in decreased

performance and increased overhead costs, causing our business and results of operations to suffer. Any significant interruption or failure of our information systems or any significant breach of security due to cyber-attacks, hacking or internal security breaches could adversely affect our business and results of operations.

Economic conditions could negatively impact our businesses.

Our businesses are affected by local, national and worldwide economic conditions. Tightening of credit in financial markets could adversely affect the ability of customers to finance purchases of our goods and services, resulting in decreased orders, cancelled or deferred orders, slower payment cycles, and increased bad debt and customer bankruptcies. Our businesses may also be adversely affected by decreases in the general level of economic activity, such as decreases in business and consumer spending. A decline in the level of economic activity and uncertainty regarding energy and commodity prices could adversely affect our results of operations and our future growth.

If we are unable to achieve the organic growth we expect, our financial performance may be adversely affected.

We expect much of our growth in the next few years will come from major capital investment at existing companies. To achieve the organic growth we expect, we must have access to the capital markets, be successful with capital expansion programs related to organic growth, develop new products and services, expand our markets and increase efficiencies in our businesses. Competitive and economic factors could adversely affect our ability to do this. If we are unable to achieve and sustain consistent organic growth, we will be less likely to meet our revenue growth targets, which, together with any resulting impact on our net income growth, may adversely affect the market price of our common shares.

Our plans to grow and realign our business mix through capital projects, acquisitions and dispositions may not be successful, which could result in poor financial performance.

As part of our business strategy, we intend to increase capital expenditures in our existing businesses and to continually assess our mix of businesses and potential strategic acquisitions or dispositions. There are risks associated with capital expenditures including not being granted timely or full recovery of rate base additions in our regulated utility business, the inability to recover the cost of capital additions due to an economic downturn, not being granted timely approval of requested interconnections to the transmission system for planned generation projects, lack of markets for new products, competition from producers of lower cost or alternative products, product defects, loss of customers or other factors. We may not be able to identify appropriate acquisition candidates or successfully negotiate, finance or integrate acquisitions. Future acquisitions could involve numerous risks including: difficulties in integrating the operations, services, products and personnel of the acquired business; and the potential loss of key employees, customers and suppliers of the acquired business. If we are unable to successfully manage these risks, we could face reductions in net income in future periods.

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We may, from time to time, sell assets to provide capital to fund investments in our electric utility business or for other corporate purposes, which could result in the recognition of a loss on the sale of any assets sold and other potential liabilities. The sale of any of our businesses also exposes us to additional risks associated with indemnification obligations under the applicable sales agreements and any related disputes.

As part of our business strategy, we continually assess our business portfolio to determine if our operating companies continue to meet our portfolio criteria. A loss on the sale of a business would be recognized if a company is sold for less than its book value.

In certain transactions we retain obligations that have arisen, or subsequently arise, out of our conduct of the business prior to the sale. These obligations are sometimes direct or, in other cases, take the form of an indemnification obligation to the buyer. These obligations include such things as warranty, environmental, and the collection of certain receivables. Unforeseen costs related to these obligations could result in future losses related to the business sold.

Significant warranty claims and remediation costs in excess of amounts normally reserved for such items could adversely affect our results of operations and financial condition.

Depending on the specific product or service, we may provide certain warranty terms against manufacturing defects and certain materials. We reserve for warranty claims based on industry experience and estimates made by management. For some of our products we have limited history on which to base our warranty estimate. Our assumptions could be materially different from any actual claim and could exceed reserve balances.

Expenses associated with the remediation of warranty claims for our manufacturing businesses, including our former wind tower manufacturer, could be substantial. The potential exists for multiple claims based on one defect repeated throughout the production process or for claims where the cost to repair or replace the defective part is highly disproportionate to the original cost of the part. If we are required to cover remediation expenses in addition to our regular warranty coverage, we could be required to accrue additional expenses and experience additional unplanned cash expenditures which could adversely affect our consolidated net income and financial condition.

We are subject to risks associated with energy markets.

Our businesses are subject to the risks associated with energy markets, including market supply and increasing energy prices. If we are faced with shortages in market supply, we may be unable to fulfill our contractual obligations to our retail, wholesale and other customers at previously anticipated costs. This could force us to obtain alternative energy or fuel supplies at higher costs or suffer increased liability for unfulfilled contractual obligations. Any significantly higher than expected energy or fuel costs would negatively affect our financial performance.

Changes in tax laws, as well as judgments and estimates used in the determination of tax-related asset and liability amounts, could materially adversely affect our business, financial condition, results of operations and prospects.

Our provision for income taxes and reporting of tax-related assets and liabilities require significant judgments and the use of estimates. Amounts of tax-related assets and liabilities involve judgments and estimates of the timing and probability of recognition of income, deductions and tax credits, including, but not limited to, estimates for potential adverse outcomes regarding tax positions that have been taken and the ability to utilize tax benefit carryforwards, such as net operating loss and tax credit carryforwards. Actual income taxes could vary significantly from estimated amounts due to the future impacts of, among other things, changes in tax laws, regulations and interpretations, the financial condition and results of operations of Otter Tail Corporation, and the resolution of audit issues raised by taxing authorities. Ultimate resolution of income tax matters may result in material adjustments to tax-related assets and liabilities, which could materially adversely affect our business, financial condition, results of operations and prospects.

Four of our operating companies have single customers that provide a significant portion of the individual operating company's and the business segment's revenue. The loss of, or significant reduction in revenue from, any one of these customers would have a significant negative financial impact on the operating company and its business segment, and could have a significant negative financial impact on the Company.

While no single customer of the Company provides more than 10% of consolidated revenue, each of the Company's segments have large customers that provide over 10% of the operating company's and its segment's revenue. In 2017 one customer accounted for 12% of Electric segment revenue, two customers accounted for a total of 36% of Manufacturing segment revenue and two customers accounted for 38% of Plastics segment revenue. The loss of any one of these customers, or a significant decline in sales to these customers, would have a significant negative impact on the operating company's and its business segment's financial position and results of operations, and could have a significant negative impact on the Company's consolidated financial position and results of operations.

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ELECTRIC

We may experience fluctuations in revenues and expenses related to our electric operations, which may cause our financial results to fluctuate and could impair our ability to make distributions to shareholders or scheduled payments on our debt obligations, or to meet covenants under our borrowing agreements.

A number of factors, many of which are beyond our control, may contribute to fluctuations in our revenues and expenses from electric operations, causing our net income to fluctuate from period to period. These risks include fluctuations in the volume and price of sales of electricity to customers or other utilities, which may be affected by factors such as mergers and acquisitions of other utilities, geographic location of other utilities, transmission costs (including increased costs related to operations of regional transmission organizations), interconnection costs, changes in the manner in which wholesale power is sold and purchased, unplanned interruptions at OTP's generating plants, the effects of regulation and legislation, demographic changes in OTP's customer base and changes in OTP's customer demand or load growth. Electric wholesale margins have been significantly and adversely affected by increased efficiencies in the MISO market. Other risks include weather conditions or changes in weather patterns (including severe weather that could result in damage to OTP's assets), fuel and purchased power costs and the rate of economic growth or decline in OTP's service areas. A decrease in revenues or an increase in expenses related to our electric operations may reduce the amount of funds available for our existing and future businesses, which could result in increased financing requirements, impair our ability to make expected distributions to shareholders or impair our ability to make scheduled payments on our debt obligations, or to meet covenants under our borrowing agreements.

Actions by the regulators of our electric operations could result in rate reductions, lower revenues and earnings or delays in recovering capital expenditures.

We are subject to federal and state legislation, government regulations and regulatory actions that may have a negative impact on our business and results of operations. The electric rates that OTP is allowed to charge for its electric services are one of the most important items influencing our financial position, results of operations and liquidity. The rates that OTP charges its electric customers are subject to review and determination by state public utility commissions in Minnesota, North Dakota and South Dakota. OTP is also regulated by the FERC. Our ability to obtain rate adjustments to maintain reasonable rates of return depends on regulatory action under applicable statutes and regulations and we cannot provide assurance that rate adjustments will be obtained or reasonable authorized rates of return on capital will be earned. OTP will file rate cases with, or seek cost recovery authorization from, federal and state regulatory authorities. On November 2, 2017 OTP filed a rate request with the NDPSC, which is pending. OTP is also an intervenor in a matter pending before the D.C. Circuit regarding FERC orders relating to the refund of RSG charges. An adverse decision by one or more regulatory commissions concerning the level or method of determining electric utility rates, the authorized returns on equity, implementation of enforceable federal reliability standards or other regulatory matters, permitted business activities (such as ownership or operation of nonelectric businesses) or any prolonged delay in rendering a decision in a rate or other proceeding (including with respect to the recovery of capital expenditures in rates) could result in lower revenues and net income.

OTP's operations are subject to an extensive legal and regulatory framework under federal and state laws as well as regulations imposed by other organizations that may have a negative impact on our business and results of operations.

We are subject to an extensive legal and regulatory framework imposed under federal and state law and regulatory agencies, including FERC and NERC. We could be subject to potential financial penalties for compliance violations. In addition, energy policy initiatives at the state or federal level could increase incentives for distributed generation or municipal utility ownership, or local initiatives could introduce generation or distribution requirements, that could change the current integrated utility model. Our transmission systems and electric generation facilities are subject to the NERC mandatory reliability standards, including cybersecurity standards. If a serious reliability incident did occur, it could have a material effect on our operations or financial results. Some states have the authority to impose substantial penalties in the event of non-compliance. We attempt to mitigate the risk of regulatory penalties through formal training. However, there is no guarantee our compliance program will be sufficient to ensure against violations.

These laws and regulations significantly influence our operations and may affect our ability to recover costs from our customers. We are required to have numerous permits, licenses, approvals and certificates from the agencies and other organizations that regulate our business. We believe we have obtained the necessary approvals for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies and other organizations. Changes in regulations or the imposition of additional regulations could have a material adverse impact on our results of operations.

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OTP's electric transmission and generation facilities could be vulnerable to cyber and physical attack that could impair our ability to provide electrical service to our customers or disrupt the U.S. bulk power system.

OTP owns electric transmission and generation facilities subject to mandatory and enforceable standards advanced by the NERC. These bulk electric system facilities provide the framework for the electrical infrastructure of OTP's service territory and interconnected systems, the operation of which is dependent on information technology systems. Further, the information systems that operate OTP's electric system are interconnected to external networks. Parties that wish to disrupt the U.S. bulk power system or OTP's operations could view OTP's computer systems, software or networks as attractive targets for cyber-attack.

In addition, OTP's generation and transmission facilities are spread throughout a large service territory. These facilities could be subject to physical attack or vandalism that could disrupt OTP's operations or conceivably the regional or U.S. bulk power system.

OTP is subject to mandatory cybersecurity and physical security regulatory requirements. OTP implements the NERC standards for operating its transmission and generation assets and stays abreast of best practices within business and the utility industry to protect its computers and computer controlled systems from outside attack. We rely on industry accepted security measures and technology to securely maintain confidential and proprietary information necessary for the operation of our systems. In an effort to reduce the likelihood and severity of cyber intrusions, we have cybersecurity processes and controls designed to protect and preserve the confidentiality, integrity and availability of data and systems. We also take prudent and reasonable steps to protect the physical security of our generation and transmission facilities. However, all these measures and technology may not adequately prevent security breaches or cyber-attacks. Any significant interruption or failure of our information systems or any significant breach of security due to cyber-attacks, hacking or internal security breaches or physical attack of our generation or transmission facilities could adversely affect our business and results of operations.

OTP's electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs.

Operation of electric generating facilities involves risks which can adversely affect energy output and efficiency levels. Most of OTP's generating capacity is coal-fired. OTP relies on a limited number of suppliers of coal, making it vulnerable to increased prices for fuel as existing contracts expire or in the event of unanticipated interruptions in fuel supply. OTP is a captive rail shipper of the BNSF Railway for shipments of coal to its Big Stone and Hoot Lake plants, making it vulnerable to increased prices for coal transportation from a sole supplier and disruptions in coal deliveries due to rail line congestion and constraints on the rail lines between the coal source mines and the plants. Higher fuel prices result in higher electric rates for OTP's retail customers through fuel clause adjustments and could make it less competitive in wholesale electric markets. Operational risks also include facility shutdowns due to breakdown or failure of equipment or processes, labor disputes, operator error and catastrophic events such as fires, explosions, floods, intentional acts of destruction or other similar occurrences affecting OTP's electric generating facilities. The loss of a major generating facility would require OTP to find other sources of supply, if available, and expose it to higher purchased power costs.

Changes to regulation of generating plant emissions, including but not limited to CO_2 emissions, could affect our operating costs and the costs of supplying electricity to our customers.

Existing or new laws or regulations passed or issued by federal or state authorities addressing climate change or reductions of GHG emissions, such as mandated levels of renewable generation, mandatory reductions in CO_2 emission levels, taxes on CO_2 emissions or cap and trade regimes, could require us to incur significant new costs, which could negatively impact our net income, financial position and operating cash flows if such costs cannot be recovered through rates granted by ratemaking authorities in the states where OTP provides service or through increased market prices for electricity. Debate continues in Congress and in the new administration on the direction and scope of U.S. and international policy on climate change and regulation of GHGs. Congress has considered but has not adopted GHG legislation which would require a reduction in GHG emissions and there is no legislation under active consideration at this time. The likelihood of any federal mandatory CO_2 emissions reduction program being adopted by Congress in the near future, and the specific requirements of any such program, are uncertain, as are the future of additional regulatory actions.

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Under the previous presidential administration, the EPA published final rules for the CPP, including NSPS regulations governing GHGs from new and existing fossil fuel-fired electric generating units and GHG performance and emissions standards for existing fossil fuel-fired power plants. The U.S. Supreme Court granted a stay of the CPP. After the new administration issued an executive order directing the EPA to consider suspending, revising, or rescinding the NSPS rule and the CPP, the D.C. Circuit issued orders holding the appellate challenges to both rules in abeyance. In October 2017, the EPA published a proposed rule to repeal the CPP and intends to solicit additional information regarding climate change and GHG emissions. The fate of the former administration's GHG rules is uncertain, as is the outcome of EPA's potential GHG regulatory actions under the new administration. The final outcome of this rulemaking process could have a material adverse impact on our business and financial results.

MANUFACTURING

Competition from foreign and domestic manufacturers, the price and availability of raw materials, prices and supply of scrap or recyclable material and general economic conditions could affect the revenues and earnings of our manufacturing businesses.

Our manufacturing businesses are subject to intense risks associated with competition from foreign and domestic manufacturers, many of whom have broader product lines, greater distribution capabilities, greater capital resources, larger marketing, research and development staffs and facilities and other capabilities that may place downward pressure on margins and profitability. The companies in our Manufacturing segment use a variety of raw materials in the products they manufacture, including steel, aluminum and polystyrene and other plastics resins. Costs for these items can fluctuate significantly. If our manufacturing businesses are not able to pass on cost increases to their customers, it could have a negative effect on profit margins in our Manufacturing segment. Additionally, a certain amount of residual material (scrap) is a by-product of many of the manufacturing and production processes used by our manufacturing companies. Declines in commodity prices for these scrap materials due to weakened demand or excess supply, can negatively impact the profitability of our manufacturing companies as it reduces their ability to mitigate the cost associated with excess material. Changes in macroeconomic conditions can negatively impact demand in the end-use markets for products and parts that we manufacture, resulting in reduced sales and profits. There is no assurance that the initiatives underway to increase revenues and improve margins at our manufacturing businesses will be successful.

PLASTICS

Our plastics operations are highly dependent on a limited number of vendors for PVC resin and a limited supply of PVC resin. The loss of a key vendor, or any interruption or delay in the supply of PVC resin, could result in reduced sales or increased costs for our plastics business.

We rely on a limited number of vendors to supply the PVC resin used in our plastics business. Two vendors accounted for 100% of our total purchases of PVC resin in 2017 and 2016. In addition, the supply of PVC resin may be limited primarily due to manufacturing capacity and the limited availability of raw material components. A majority of U.S. resin production plants are located in the Gulf Coast region, which may increase the risk of a shortage of resin in the event of a hurricane or other natural disaster in that region. The loss of a key vendor or any interruption or delay in the availability or supply of PVC resin could disrupt our ability to deliver our plastic products, cause customers to cancel orders or require us to incur additional expenses to obtain PVC resin from alternative sources, if such sources are available.

We compete against a large number of other manufacturers of PVC pipe and manufacturers of alternative products. Customers may not distinguish our products from those of our competitors.

The plastic pipe industry is fragmented and competitive due to the number of producers and the fungible nature of the product. We compete not only against other plastic pipe manufacturers, but also against ductile iron, steel and concrete pipe manufacturers. Due to shipping costs, competition is usually regional instead of national in scope, and the principal areas of competition are a combination of price, service, warranty, and product performance. Our inability to compete effectively in each of these areas and to distinguish our plastic pipe products from competing products may adversely affect the financial performance of our plastics business.

Changes in PVC resin prices can negatively affect our plastics business.

The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices are rising or stable, margins and sales volume have been higher and when resin prices are falling, sales volumes and margins have been lower. Changes in PVC resin prices can negatively affect PVC pipe prices, profit margins on PVC pipe sales and the value of our finished goods inventory.

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Item 1B. UNRESOLVED STAFF COMMENTS

None.

Item 2. PROPERTIES

The Coyote Station, which commenced operation in 1981, is a 414,000 kW (nameplate rating) mine-mouth plant located in the lignite coal fields near Beulah, North Dakota and is jointly owned by OTP, Northern Municipal Power Agency, Montana-Dakota Utilities Co. and Northwestern Public Service Company. OTP is the operating agent of the Coyote Station and owns 35% of the plant.

OTP, jointly with Northwestern Public Service Company and Montana-Dakota Utilities Co., owns the 414,000 kW (nameplate rating) Big Stone Plant in northeastern South Dakota which commenced operation in 1975. OTP is the operating agent of Big Stone Plant and owns 53.9% of the plant.

Located near Fergus Falls, Minnesota, the Hoot Lake Plant is comprised of two separate generating units: a unit built in 1959 (53,500 kW nameplate rating) and a unit added in 1964 (75,000 kW nameplate rating) and modified in 1988 to provide cycling capability, allowing this unit to be more efficiently brought online from a standby mode. These two generating units have a combined nameplate rating of 128,500 kW. Current plans are for both units to be retired from service in 2021.

OTP owns 27 wind turbines at the Langdon, North Dakota Wind Energy Center with a nameplate rating of 40,500 kW, 32 wind turbines at the Ashtabula Wind Energy Center located in Barnes County, North Dakota with a nameplate rating of 48,000 kW and 33 wind turbines at the Luverne Wind Farm located in Steele County, North Dakota with a nameplate rating of 49,500 kW.

As of December 31, 2017 OTP's transmission facilities, which are interconnected with lines of other public utilities, consisted of 606 pole-miles of jointly owned 345 kV lines; 494 pole-miles of 230 kV lines, of which 70 miles are jointly owned; 879 pole-miles of 115 kV lines; and 3,973 pole-miles of lower voltage lines, principally 41.6 kV. OTP owns the uprated portion of 48 pole-miles of the 345 kV lines, with Minnkota Power Cooperative retaining title to the original 230 kV construction, and OTP owns an undivided interest in the remaining 345 kV line miles. OTP is a joint owner, with other regional utilities, in transmission lines with the following ownership interests: 14.8% in the 70 mile Bemidji-Grand Rapids 230 kV line, approximately 14.2% of 242 pole-miles of energized line in the Fargo-Monticello 345 kV project, approximately 4.8% of 255 pole-miles of energized line in the Brookings to Southeast Twin Cities 345 kV project, and 50.0% of 72 pole-miles of energized line in the Big Stone South–Brookings 345 kV project.

In addition to the properties mentioned above, all of which are utilized by the Electric segment, the Company owns and has investments in offices and service buildings utilized by each of its manufacturing and plastic pipe companies. The Company's subsidiaries own facilities and equipment used in: the manufacture of PVC pipe, thermoformed products, heavy metal fabricated products, metal parts stamping, fabricating, painting and contract machining.

Management of the Company believes the facilities and equipment described above are adequate for the Company's present businesses.

Item 3. LEGAL PROCEEDINGS

The Company is the subject of various pending or threatened legal actions and proceedings in the ordinary course of its business. Such matters are subject to many uncertainties and to outcomes that are not predictable with assurance. The Company records a liability in its consolidated financial statements for costs related to claims, including future legal costs, settlements and judgments, where the Company has assessed that a loss is probable and an amount can be reasonably estimated. The Company believes the final resolution of currently pending or threatened legal actions and proceedings, either individually or in the aggregate, will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

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Item 3A. EXECUTIVE OFFICERS OF THE REGISTRANT (AS OF FEBRUARY 20, 2018)

Set forth below is a summary of the principal occupations and business experience during the past five years of the executive officers as defined by rules of the SEC. Each of the executive officers, excluding John Abbott, has been employed by the Company for more than five years in an executive or management position either with the Company or its wholly owned subsidiary, Otter Tail Power Company.

NAME AND AGE	DATE ELECTED TO OFFICE	PRESENT POSITION AND BUSINESS EXPERIENCE	
Charles S. MacFarlane (53)	4/13/15	Present:	President and Chief Executive Officer
Kevin G. Moug (58)	4/9/01	Present:	Chief Financial Officer and Senior Vice President
Timothy J. Rogelstad (51)	4/14/14	Present:	Senior Vice President, Electric Platform
John Abbott (59)	2/11/15	Present:	Senior Vice President, Manufacturing Platform
Jennifer O. Smestad (47)	1/1/18	Present:	Vice President, General Counsel and Corporate Secretary

On April 13, 2015 Mr. MacFarlane was elected as the Company's President and Chief Executive Officer and as member of the Company's board of directors. On February 5, 2014 the Company's board of directors appointed Mr. MacFarlane, then President and Chief Executive Officer of OTP and Senior Vice President, Electric Platform of the Company, to the role of President and Chief Operating Officer of the Company, effective April 14, 2014. Mr. MacFarlane joined OTP in 2001 and had served as its President from 2003 to 2014 and its Chief Executive Officer from 2007 to 2014. He served as Senior Vice President, Electric platform of the Company from 2012 to 2014. Prior to joining OTP, Mr. MacFarlane served as Director of Electric Distribution Planning and Engineering for Xcel Energy Inc.'s multi-state service territory. He was also Director of Delivery Construction and Field Operations for Northern States Power Company prior to its merger with New Centuries Energy and becoming Xcel Energy.

Kevin G. Moug has held his present positions with the Company for more than five years.

On April 14, 2014 Timothy J. Rogelstad was appointed to succeed Mr. MacFarlane as President of OTP and Senior Vice President, Electric Platform of the Company. Mr. Rogelstad joined OTP in June 1989 as an engineer in the System Engineering Department and served as Supervisor, Transmission Planning, and Manager, Delivery Planning, before being named Vice President, Asset Management, in 2012. In the role of Vice President, Asset Management at OTP, he was in charge of OTP's Delivery Planning, Delivery Maintenance, Delivery Engineering, System Operations, and Project Management Departments. Mr. Rogelstad is a registered professional engineer in the three states where OTP serves, Minnesota, North Dakota, and South Dakota.

On February 5, 2015 John Abbott was selected to serve as Senior Vice President, Manufacturing Platform, and President of Varistar. Prior to coming to the Company, Mr. Abbott served as an officer and group vice president for eight years at Standex International Corporation (Standex), a group of restaurant equipment companies. During his last five years at Standex, Mr. Abbott served as Group Vice President, Food Service Equipment Group. In this role, Mr. Abbott was responsible for all strategic and

operational aspects of the Food Service Equipment business. Prior to working at Standex, Mr. Abbott was with Pentair for 20 years, rising from product manager to president and global business unit leader of its water filtration division.

On December 19, 2017 the Company's board of directors appointed Jennifer O. Smestad to the position of Vice President, General Counsel and Corporate Secretary of the Company, effective January 1, 2018, to succeed George A. Koeck, Senior Vice President, General Counsel and Corporate Secretary who retired effective December 31, 2017. Ms. Smestad joined the Company on May 14, 2001 as an Associate General Counsel and has served in various legal capacities of increasing responsibility at the Company and at OTP. She most recently served as General Counsel for OTP from March 1, 2013 to the present.

The term of office for each of the executive officers is one year and any executive officer elected may be removed by the vote of the board of directors at any time during the term. There are no family relationships between any of the executive officers or directors.

Item 4. MINE SAFETY DISCLOSURES

Not Applicable.

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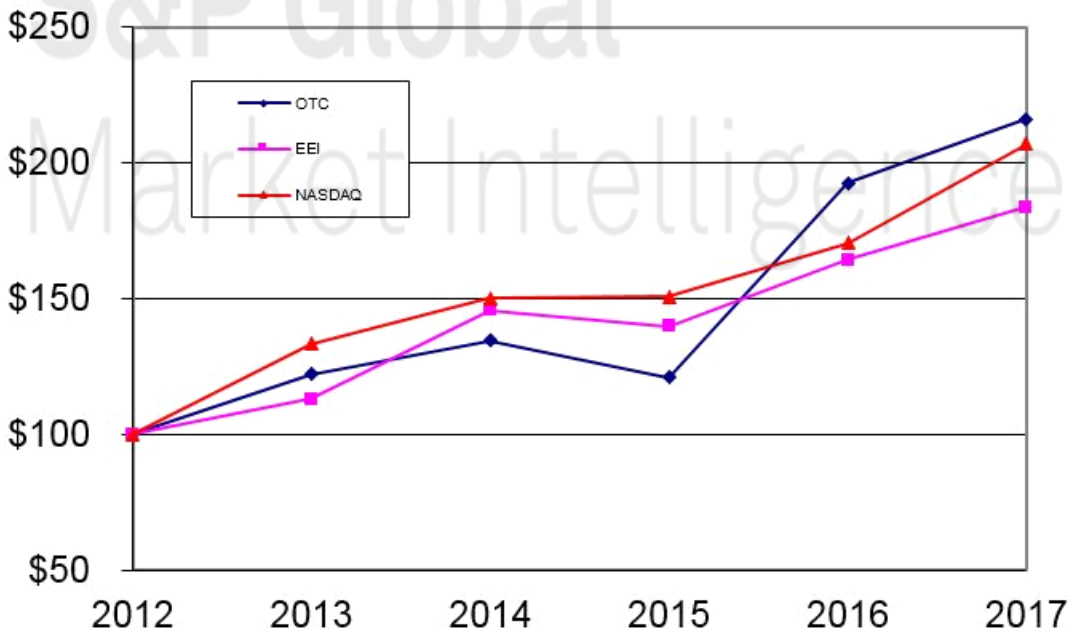
PART II

Item 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The Company's common stock is traded on the NASDAQ Global Select Market under the NASDAQ symbol "OTTR". The information required by this Item can be found on Page 37 of this Annual Report on Form 10-K under the heading "Selected Financial Data," on Page 93 under the heading "Retained Earnings and Dividend Restriction" and on Page 115 under the heading "Supplementary Financial Information." The Company does not have a publicly announced stock repurchase program. The Company did not repurchase any equity securities during the three months ended December 31, 2017.

PERFORMANCE GRAPH
COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN

This graph compares the cumulative total shareholder return on the Company's common shares for the last five fiscal years with the cumulative return of The NASDAQ Stock Market Index and the Edison Electric Institute (EEI) Index over the same period (assuming the investment of $100 in each vehicle on December 31, 2012, and reinvestment of all dividends).



	2012	2013	2014	2015	2016	2017
OTC	**$ 100.00**	**$ 122.07**	**$ 134.51**	**$ 120.99**	**$ 192.46**	**$ 216.23**
EEI	**$ 100.00**	**$ 113.01**	**$ 145.68**	**$ 139.99**	**$ 164.40**	**$ 183.66**
NASDAQ	**$ 100.00**	**$ 133.48**	**$ 150.12**	**$ 150.84**	**$ 170.46**	**$ 206.91**

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Item 6. SELECTED FINANCIAL DATA

(thousands, except number of shareholders and per-share data)	**2017**	2016	2015	2014	2013
Revenues					
Electric	**$ 434,537**	$ 427,383	$ 407,131	$ 407,743	$ 373,540

Manufacturing	**229,738**	221,289	215,011	219,583	204,997
Plastics	**185,132**	154,901	157,758	172,050	164,957
Intersegment Eliminations	**(57)**	(34)	(96)	(114)	(80)
Total Operating Revenues	**$ 849,350**	$ 803,539	$ 779,804	$ 799,262	$ 743,414
Net Income from Continuing Operations	**$ 72,119**	$ 62,037	$ 58,589	$ 56,883	$ 48,595
Net Income from Discontinued Operations	**320**	284	756	840	2,270
Net Income	**$ 72,439**	$ 62,321	$ 59,345	$ 57,723	$ 50,865
Operating Cash Flow from Continuing Operations	**$ 173,603**	$ 163,541	$ 131,540	$ 125,769	$ 142,408
Operating Cash Flow - Continuing and Discontinued Operations	**173,577**	163,386	117,540	112,474	147,781
Capital Expenditures - Continuing Operations	**132,913**	161,259	160,084	163,582	159,833
Total Assets	**2,004,278**	1,912,385	1,818,683	1,738,116	1,558,190
Long-Term Debt	**490,380**	505,341	443,846	495,906	387,212
Basic Earnings Per Share - Continuing Operations *(1)*	**1.83**	1.61	1.56	1.56	1.33
Basic Earnings Per Share - Total *(1)*	**1.84**	1.62	1.58	1.58	1.39
Diluted Earnings Per Share - Continuing Operations *(1)*	**1.81**	1.60	1.56	1.55	1.33
Diluted Earnings Per Share - Total *(1)*	**1.82**	1.61	1.58	1.57	1.39
Return on Average Common Equity *(2)*	**10.6%**	9.8%	10.1%	10.4%	9.5%
Dividends Declared Per Common Share	**1.28**	1.25	1.23	1.21	1.19
Dividend Payout Ratio	**70%**	78%	78%	77%	86%
Common Shares Outstanding - Year End	**39,557**	39,348	37,857	37,218	36,272
Number of Common Shareholders *(3)*	**13,053**	13,805	14,062	14,134	14,252

(1) Based on average number of shares outstanding.
(2) Earnings available for common shares divided by the 13-month average of month-end common equity balances.
(3) Holders of record at year end.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

Otter Tail Corporation and its subsidiaries form a diverse group of businesses with operations classified into three segments: Electric, Manufacturing and Plastics. Our primary financial goals are to maximize earnings and cash flows and to allocate capital profitably toward growth opportunities that will increase shareholder value. Meeting these objectives enables us to preserve and enhance our financial capability by maintaining desired capitalization ratios and a strong interest coverage position and preserving investment grade credit ratings on outstanding securities, which, in the form of lower interest rates, benefits both our customers and shareholders.

Our strategy is to continue to grow our largest business, the regulated electric utility, which will lower our overall risk, create a more predictable earnings stream, improve our credit quality and preserve our ability to fund the dividend. Over time, we expect the electric utility business will provide approximately 75% to 85% of our overall earnings. We expect our manufacturing and plastic pipe businesses will provide 15% to 25% of our earnings, and will continue to be a fundamental part of our strategy. The actual mix of earnings from continuing operations in 2017, 2016 and 2015 was 69%, 80% and 83%, respectively, from our electric utility business and 31%, 20% and 17%, respectively, from our manufacturing and plastic pipe businesses, including unallocated corporate costs.

Reliable utility performance along with rate base investment opportunities over the next five years will provide us with a strong base of revenues, earnings and cash flows. We also look to our manufacturing and plastic pipe companies to provide organic growth as well. Organic, internal growth comes from new products and services, market expansion and increased efficiencies. We expect much of our growth in these businesses in the next few years will come from utilizing expanded plant capacity from capital investments made in previous years. We will also evaluate opportunities to allocate capital to potential acquisitions in our Manufacturing and Plastics segments. We are a committed long-term owner and therefore we do not acquire companies in pursuit of short-term gains. However, we will divest operating companies that no longer fit into our strategy and risk profile over the long term. In the period 2011 through 2015 we sold several businesses in execution of our announced strategy to realign our portfolio of businesses and refocus our capital investment in the electric utility.

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Major growth strategies and initiatives in our future include:

- Planned capital budget expenditures of up to $973 million for the years 2018 through 2022, of which $901 million are for capital projects at Otter Tail Power Company (OTP), including:
  - $302 million for renewable wind and solar energy generation projects including the Merricourt Wind Project. In November 2016 OTP signed agreements to purchase this 150-megawatt (MW) wind farm in southeastern North Dakota that EDF Renewable Energy will design and build in 2019, subject to certain conditions.
  - $161 million for natural gas-fired generation to replace Hoot Lake Plant capacity.
  - $136 million for transformative technology and infrastructure projects including automated metering, telecommunications, geographic information systems, work and asset management systems, financial information systems, system infrastructure reliability improvements, outage management systems, and storage projects.
  - $35 million for a transmission project designated by the Midcontinent Independent System Operator, Inc. (MISO) as a Multi-Value Project (MVP).
- Continued investigation and evaluation of organic growth opportunities and evaluation of opportunities to allocate capital to potential acquisitions in our Manufacturing and Plastics segments.

In 2017:

- Our Plastics segment net income increased 104.1% to $21.7 million from $10.6 million in 2016.
- Our Manufacturing segment net income increased 94.1% to $11.1 million from $5.7 million in 2016.

- Our Electric segment net income decreased 0.8% to $49.4 million from $49.8 million in 2016.
- Our net cash from continuing operations was $173.6 million.
- Capital expenditures at OTP totaled $118.4 million as work was completed on one major MISO-designated MVP and work continued on another MISO-designated MVP.
- We raised net proceeds of $4.3 million from the issuance of 112,548 shares of common stock through our stock plans.
- We increased short-term borrowing by $69.5 million, retiring long-term debt and funding a portion of OTP's 2017 capital expenditures. We paid $48.2 million to repay long-term debt, including the retirement of $33.0 million of OTP's 5.95% notes due in August 2017 and the early repayment of $15.0 million of our LIBOR plus 0.90% term loan due February 5, 2018.
- We paid out $50.6 million in common dividends in 2017.

The following table summarizes our consolidated results of operations for the years ended December 31:

(in thousands)	2017	2016
Operating Revenues:		
Electric	$ 434,506	$ 427,349
Manufacturing	229,712	221,289
Plastics	185,132	154,901
Total Operating Revenues	$ 849,350	$ 803,539
Net Income (Loss) From Continuing Operations:		
Electric	$ 49,446	$ 49,829
Manufacturing	11,050	5,694
Plastics	21,696	10,628
Corporate	(10,073)	(4,114)
Total Net Income From Continuing Operations	$ 72,119	$ 62,037

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Revenues in each of our business segments increased in 2017 compared with 2016. Major factors contributing to the $30.2 million (19.5%) increase in Plastics segment revenues were a 7.2% increase in pounds of polyvinyl chloride (PVC) pipe sold and 11.5% increase in PVC pipe prices. Buying spurred by concerns of product shortages and production delays related to 2017 hurricanes in the Gulf of Mexico resulted in an estimated $3.4 million increase in segment net income in 2017. Manufacturing segment revenues increased $8.4 million (3.8%). Revenues at BTD Manufacturing, Inc. (BTD) showed a net increase of $5.9 million, with revenue increases at BTD's Minnesota and Georgia facilities increasing by 4.0% and 8.2%, respectively, as a result of increased product sales to manufacturers of recreational and lawn and garden equipment. Revenues at T.O. Plastics, Inc. (T.O. Plastics) increased $2.5 million as a result of significant increases in sales of life science and horticultural products. Electric segment revenues increased $7.2 million (1.7%) mainly as a result of increased transmission services revenue driven by increased investment in regional transmission lines with returns earned while the lines are under construction and increased revenues earned from the use of energized lines by other electric service providers.

The $10.1 million increase in net income from continuing operations in 2017 compared with 2016 reflects the following:

- An $11.1 million increase in Plastics segment net income due to hurricane related sales, the positive effect of the 2017 Tax Cuts and Jobs Act (TCJA) tax rate reduction on the segment's deferred tax liabilities and increases in normal business sales.
- A $5.4 million increase in Manufacturing segment net income, mainly due to increased sales to manufacturers of recreational and lawn and garden equipment and life science and horticultural products. BTD also benefited from the effect of the TCJA tax rate reduction on its deferred tax liabilities.

offset by:

- A $0.4 million decrease in Electric segment net income due to increases in fuel and purchased power costs and higher property tax expenses, and a negative effect of the TCJA tax rate reduction on Electric segment deferred tax assets related to a portion of accrued postretirement benefit costs which are not recoverable in regulated rates.
- A $6.0 million net-of-tax increase in Corporate net losses mainly as a result of the negative effect of the TCJA tax rate reduction on deferred tax assets at the holding company.

As a result of the tax rate reduction included in the TCJA, deferred tax assets and liabilities were reduced in value. Following is the impact by segment on income tax expense:

(in thousands)	**Decrease/(Increase)**
Electric	$ (458)
Manufacturing	2,637
Plastics	3,263
Corporate	(7,198)
Total	$ (1,756)

These are provisional amounts based on reasonable estimates reflecting the anticipated impact of the TCJA.

Following is a more detailed analysis of our operating results by business segment for the years ended December 31, 2017, 2016 and 2015, followed by a discussion of our financial position at the end of 2017 and our outlook for 2018.

RESULTS OF OPERATIONS

This discussion and analysis should be read in conjunction with our consolidated financial statements and related notes. See note 2 to consolidated financial statements for a complete description of our lines of business, locations of operations and principal products and services.

Intersegment Eliminations—Amounts presented in the following segment tables for 2017, 2016 and 2015 operating revenues, cost of goods sold and other nonelectric operating expenses will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

Intersegment Eliminations *(in thousands)*	2017	2016	2015
Operating Revenues:			
Electric	$ 31	$ 34	$ 92
Product Sales	26	--	4
Cost of Products Sold	18	6	9
Other Nonelectric Expenses	39	28	87

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ELECTRIC

The following table summarizes the results of operations for our Electric segment for the years ended December 31:

(in thousands)	2017	% change	2016	% change	2015
Retail Sales Revenues	$ 374,931	--	$ 376,610	3	$ 364,614
Wholesale Revenues – Company Generation	5,173	13	4,584	83	2,499
Net Revenue – Energy Trading Activity	--	--	--	(100)	186
Other Revenues	54,433	18	46,189	16	39,832
Total Operating Revenues	$ 434,537	2	$ 427,383	5	$ 407,131
Production Fuel	59,690	9	54,792	28	42,744
Purchased Power – System Use	64,807	3	63,226	(19)	78,150
Other Operation and Maintenance Expenses	151,319	--	151,225	7	140,768
Depreciation and Amortization	53,276	(1)	53,743	20	44,786
Property Taxes	15,053	6	14,266	6	13,512
Operating Income	$ 90,392	--	$ 90,131	3	$ 87,171
Electric kilowatt-hour (kwh) Sales *(in thousands)*					
Retail kwh Sales	4,814,984	1	4,750,421	3	4,593,604
Wholesale kwh Sales – Company Generation	203,397	7	190,288	77	107,510
Wholesale kwh Sales – Purchased Power Resold	--	--	--	(100)	5,547
Heating Degree Days	5,931	12	5,314	(6)	5,633
Cooling Degree Days	380	(16)	451	(7)	483

The following table shows heating and cooling degree days as a percent of normal:

	2017	2016	2015
Heating Degree Days	93.9%	84.1%	88.2%
Cooling Degree Days	82.1%	97.4%	103.4%

The following table summarizes the estimated effect on diluted earnings per share of the difference in retail kwh sales under actual weather conditions and expected retail kwh sales under normal weather conditions in 2017, 2016 and 2015, and between years:

	2017 vs Normal	2017 vs 2016	2016 vs Normal	2016 vs 2015	2015 vs Normal
Effect on Diluted Earnings Per Share	$ (0.036)	$ 0.031	$ (0.067)	$ (0.023)	$ (0.044)

2017 Compared with 2016

The $1.7 million decrease in retail electric revenue includes:

- A $5.3 million increase in retail revenue related to the recovery of increased fuel and purchased power costs due to a 1.4% increase in kwhs sold and a 4.8% increase in fuel and purchased power costs per kwh.
- A $4.2 million increase in Minnesota base rate revenue mainly due to the transfer of recovery of environmental and transmission costs and investments from riders to base rates.
- A $2.0 million increase in revenues due to increased consumption related to colder weather in 2017 reflected in the 11.6% increase in heating degree days between the years.
- A $1.0 million increase in North Dakota Transmission Cost Recovery (TCR) rider revenues as a result of increased investment in transmission assets qualifying for revenue recovery through the TCR rider.

offset by:

- A $7.1 million reduction in Minnesota Environmental Cost Recovery (ECR) rider and TCR rider revenues due to the transfer of recovery of qualifying costs from rider recovery into base rates, and due to declining revenue requirements related to lower asset values due to accumulated depreciation. Additionally, a lower return on equity in the MISO transmission tariff related to complaints currently under judicial review resulted in lower TCR revenues in Minnesota.

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- A $3.7 million decrease in Minnesota Conservation Improvement Program (MNCIP) incentive and cost recovery revenues related to a $2.5 million reduction in

incentives earned due to lower incentive rates and a $1.2 million reduction in spending on MNCIP programs. In 2017 OTP began operating under a new MNCIP program that was authorized by the Minnesota Public Utilities Commission. This new program lowered the incentive payout by 50% in 2017. The $1.2 million reduction in spending was due to a delay in regulatory approval for the implementation of an LED streetlight project.

- A $1.9 million decrease in revenue due to a change in estimate that reduced unbilled revenues.
- A $1.5 million decrease in North Dakota and South Dakota ECR rider revenues resulting from lower values on qualifying assets due to accumulated depreciation.

The $0.6 million increase in revenue from wholesale electric sales from company-owned generation was mostly offset by a $0.4 million increase in fuel costs for wholesale generation.

The $8.2 million increase in other electric revenues includes:

- A $7.8 million increase in MISO transmission tariff revenues, mainly driven by increased investment in regional transmission lines and revenues earned from the use of those lines by other electric service providers.
- A $0.4 million increase in other revenues, mainly steam sales at Big Stone Plant.

Production fuel costs increased $4.9 million due to a 4.0% increase in kwhs generated. This was due to increase generation from Coyote Station and Hoot Lake Plant because of Coyote Station's greater availability, increased demand due to colder weather in 2017 and higher market prices for electricity that resulted in increased dispatch of Hoot Lake Plant.

The cost of purchased power to serve retail customers increased $1.6 million despite a 3.4% decrease in kwhs purchased. This was a result of higher market prices for electricity driven by increased demand in 2017 due, in part, to colder weather in 2017 than in 2016.

Electric operating and maintenance expenses increased $0.1 million as a result of:

- A $3.2 million increase in labor and benefit costs due to increased wages and higher medical benefit payments.

offset by:

- A $1.2 million decrease in transmission expenditures to independent system operators in 2017.
- A $1.2 million decrease in MNCIP expenditures due to a delay in regulatory approval of an LED streetlight project planned for 2017.
- A $0.7 million net reduction in other operating expenses.

Depreciation and amortization expense decreased $0.5 million due to lower depreciation rates.

Property tax expense increased $0.8 million mainly due to transmission line additions in South Dakota related to the construction of the Big Stone South–Ellendale and Big Stone South–Brookings 345-kiloVolt (kV) transmission projects.

2016 Compared with 2015
The $12.0 million increase in retail revenue includes:

- An $11.0 million increase in retail revenue related to a 9.56% interim rate increase implemented in April 2016 in conjunction with OTP's 2016 general rate increase request in Minnesota.
- A $4.4 million increase in ECR rider revenue due to the recovery of additional investment and costs related to the operation of the air quality control system (AQCS) at Big Stone Plant that was placed in service in December 2015.
- A $4.3 million increase in revenue related to an increase in retail kwh sales, mainly to pipeline customers.
- A $2.2 million increase in TCR rider revenues related to increased investment in transmission plant.
- A $1.7 million increase in MNCIP cost recovery revenues directly related to additional MNCIP activities.

offset by:

- A $5.7 million decrease in fuel and purchased power cost recovery revenues mainly due to an 11.4% decrease in kwhs purchased partially offset by a 19.7% kwh increase in generation.
- A $3.6 million reduction in interim rate revenues recorded to provide for an estimated refund related to a modification in OTP's original request and other expected outcomes in the pending Minnesota general rate case.

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- A $1.6 million decrease in revenues related to decreased consumption due to milder weather in 2016, evidenced by a 5.7% reduction in heating-degree days and 6.6% reduction in cooling-degree days between the years.
- A $0.6 million decrease in Renewable Resource Adjustment rider revenues in North Dakota, which were down as a result of earning more federal Production Tax Credits (PTCs) to pass back to customers due to a 3.6% increase in kwhs generated from wind turbines eligible for PTCs.

A $2.1 million increase in revenue from wholesale electric sales from company-owned generation was partially offset by a $1.5 million increase in fuel costs for wholesale generation, resulting in a $0.6 million increase in wholesale revenue net of fuel costs as increased plant availability in 2016 provided greater opportunity for OTP to respond to

market demand.

Other electric revenues increased $6.4 million as a result of:

- A $4.8 million increase in MISO transmission tariff revenues, mainly driven by increased investment in regional transmission lines and related returns on and recovery of Capacity Expansion 2020 and MISO-designated MVP investment costs and operating expenses.
- A $3.0 million increase in MISO network integration transmission service revenues due to a regional transmission cooperative terminating its integrated transmission agreement with OTP and joining the Southwest Power Pool (SPP) in 2016.

offset by:

- A $1.3 million decrease in revenue related to a reduction in integrated transmission agreement revenues from two regional transmission providers related to the curtailment of services under one agreement and the discontinuance of another agreement.

Production fuel costs increased $12.0 million as a result of a 27.1% increase in kwhs generated from our steam-powered and combustion turbine generators related to Big Stone Plant being fully operational in 2016 after the tie in of the AQCS in 2015, as well as Coyote Station being available to run at full load in 2016 after being restricted to half load in 2015 because of boiler feed water pump problems.

The cost of purchased power to serve retail customers decreased $14.9 million due to an 11.4% decrease in kwhs purchased in combination with an 8.7% decrease in the cost per kwh purchased. Greater availability of company-owned generation in 2016 reduced the need to purchase electricity to serve retail load. The decreased cost per kwh purchased was driven by lower market demand mainly resulting from milder weather in 2016 compared with 2015.

Electric operating and maintenance expenses increased $10.5 million as a result of:

- $3.7 million in transmission expenses from the SPP as a result of a regional transmission cooperative terminating its integrated transmission agreement with OTP and joining the SPP in 2016.
- A $1.9 million increase in pollution control reagent costs at Big Stone Plant and Coyote Station related to compliance with the Environmental Protection Agency power plant emission regulations.
- A $1.7 million increase in MNCIP program expenditures related to additional MNCIP activities.
- A $1.3 million increase in MISO transmission service charges due to increased transmission investment by other MISO members.
- A $1.1 million increase in storm repair expenses associated with excessive storm damage in OTP's Minnesota service area in July 2016 and in its North Dakota and South Dakota service areas in December 2016.
- $0.8 million related to increases in other expense categories.

Depreciation and amortization expense increased $9.0 million mainly due to the AQCS at Big Stone Plant being placed in service in December 2015 along with increased investment in transmission assets with the final phases of the Fargo-Monticello and Brookings-Southeast Twin Cities 345-kV transmission lines placed in service near the end of the first quarter of 2015.

The $0.8 million increase in property tax expense is related to property additions in Minnesota and North Dakota in 2015.

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MANUFACTURING

The following table summarizes the results of operations for our Manufacturing segment for the years ended December 31:

(in thousands)	2017	% change	2016	% change	2015
Operating Revenues	$ 229,738	4	$ 221,289	3	$ 215,011
Cost of Products Sold	176,473	3	171,732	--	171,956
Other Operating Expenses	23,785	8	21,994	4	21,116
Depreciation and Amortization	15,379	(3)	15,794	33	11,853
Operating Income	$ 14,101	20	$ 11,769	17	$ 10,086

2017 Compared with 2016

The $8.4 million increase in revenues in our Manufacturing segment in 2017 compared with 2016 relates to the following:

- Revenues at BTD increased $5.9 million. This is due to a $3.3 million increase in product sales to manufacturers of recreational and lawn and garden equipment from BTD's Minnesota and Georgia manufacturing facilities, offset by lower sales in the energy end-use market at the Illinois facility. Scrap revenues increased $2.6 million due to increased volume and higher scrap-metal prices.
- Revenues at T.O. Plastics, Inc. (T.O. Plastics) increased $2.5 million, including increases of $1.3 million from sales of life science products, $1.0 million from sales of horticultural products and $0.2 million from sales of industrial products.

The $4.7 million increase in cost of products sold in our Manufacturing segment includes the following:

- Cost of products sold at BTD increased $2.3 million as a result of the increase in product sales.
- Costs of products sold at T.O. Plastics increased $2.4 million due to the increase in sales.

The $1.8 million increase in Manufacturing segment operating expenses includes the following:

- Operating expenses at BTD increased $1.9 million as a result of the following:
  - A $0.7 million increase in labor and benefit costs as a result of an increase in employees in a growing business.
  - A $0.4 million increase in contracted service expenditures for consulting, software and telecommunications in response to increased business needs.
  - A $0.4 million increase in property taxes.
  - A $0.4 million increase in insurance costs.
- Operating expenses at T.O. Plastics decreased $0.1 million between the years.

The $0.4 million decrease in depreciation in our Manufacturing segment includes decreases of $0.3 million at T.O. Plastics million due to certain assets reaching the ends of their depreciable lives in 2017. Depreciation expense at BTD was down $0.1 million year over year.

2016 Compared with 2015

The increase of $6.3 million in revenues in our Manufacturing segment in 2016 compared with 2015 relates to the following:

- Revenues at BTD increased $9.8 million, including:
  - A $15.4 million increase in revenues at BTD-Georgia as a result of BTD owning and operating this plant for the entire year of 2016 compared to four months in 2015.
  - A $9.6 million increase in revenues mainly related to the production of wind tower components.

  offset by:
  - A $15.2 million decrease in revenues related to lower sales to manufacturers of recreational and agricultural equipment due to softness in end markets served by those manufacturers.
- Revenues at T.O. Plastics decreased $3.5 million, including:
  - A $3.0 million decrease in revenue related to a continued decline in sales to a customer insourcing product into its own manufacturing facilities.
  - A $0.6 million decrease in sales of horticultural products due to sales execution challenges, including lower sales to a major distributor.

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  offset by:
  - A net $0.1 million increase in sales of other products in the industrial and life sciences markets.

The $0.2 million decrease in cost of products sold in our Manufacturing segment includes the following:

- Cost of products sold at BTD increased $1.7 million. This includes a $15.5 million increase in cost of products sold at BTD-Georgia, offset by a $13.8 million net decrease in cost of products sold at BTD's other facilities. The $13.8 million decrease is related to the decrease in sales, partially offset by an increase in costs of products sold at BTD's Illinois plant as a result of the increase in the production of wind tower components.
- Cost of products sold at T.O. Plastics decreased $1.9 million related to the decrease in sales.

Gross margins at BTD were positively impacted in 2016 by changes in customer product mix between periods.

The $0.9 million increase in operating expenses in our Manufacturing segment includes the following:

- Operating expenses at BTD increased $1.4 million, of which $1.2 million was due to a full year of operations at BTD-Georgia in 2016.
- Operating expenses at T.O. Plastics decreased $0.4 million, primarily as a result of a $0.5 million decrease in selling expenses.

The $3.9 million increase in depreciation and amortization expenses in our Manufacturing segment includes a $2.3 million increase at BTD-Georgia and a $1.8 million increase at BTD's other plants mainly as a result of placing new assets in service in Minnesota in 2015 and 2016. Depreciation expense at T.O. Plastics decreased $0.2 million between the years.

PLASTICS

The following table summarizes the results of operations for our Plastics segment for the years ended December 31:

(in thousands)	2017	% change	2016	% change	2015
Operating Revenues	$ 185,132	20	$ 154,901	(2)	$ 157,758
Cost of Products Sold	140,107	13	123,496	--	123,085
Other Operating Expenses	11,564	23	9,402	(5)	9,849
Depreciation and Amortization	3,817	(1)	3,861	9	3,552
Operating Income	$ 29,644	63	$ 18,142	(15)	$ 21,272

2017 Compared with 2016

Plastics segment revenues increased $30.2 million as a result of a 7.2% increase in pounds of PVC pipe sold and an 11.5% increase in PVC pipe prices between the years. Reaction to the hurricanes in the Gulf Coast region of the United States resulted in an estimated $12.5 million increase in revenues. The majority of U.S. PVC resin production plants are located in the Gulf Coast region. Major resin suppliers shut down production facilities which impacted raw material availability. Distributors and contractors became concerned about pipe availability. This accelerated pipe demand and created positive sales price pressure in the market. Year over year improvement in normal business operations provided for the remainder of the revenue increase, along with increased prices. The $16.6 million increase in Plastics segment costs of product sold was due to the increase in sales volume and a 5.9% increase in the cost per pound of PVC pipe sold. The $2.2 million increase in operating expenses is mostly due to employee incentive pay related to the pipe companies' stronger financial results compared with 2016.

2016 Compared with 2015

The $2.9 million decrease in Plastics segment revenues is the result of an 11.2% decrease in the price per pound of pipe sold, partially offset by a 10.5% increase in pounds of pipe sold. The decline in sales price per pound is related to lower raw material prices between the periods. Increased pipe sales in the Colorado, Utah, and the South Central and Northwest regions of the United States were partially offset by decreased sales volumes in Montana, South Dakota and Minnesota. Cost of products sold increased $0.4 million due to the increase in sales volume, partly offset by a 9.2% decrease in the cost per pound of PVC pipe sold, as sales prices declined more than raw material prices. Lower margins have resulted in reduced incentive compensation, which is the primary factor contributing to the $0.4 million decrease in Plastics segment operating expenses.

The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices are rising or stable, margins and sales volume have been higher and when resin prices are falling, sales volumes and margins have been lower.

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CORPORATE

Corporate includes items such as corporate staff and overhead costs, the results of our captive insurance company and other items excluded from the measurement of operating segment performance. Corporate is not an operating segment. Rather, it is added to operating segment totals to reconcile to totals on our consolidated statements of income.

(in thousands)	2017	% change	2016	% change	2015
Other Operating Expenses	$ 7,930	(11)	$ 8,896	(3)	$ 9,143
Depreciation and Amortization	73	55	47	(73)	172

Corporate operating expenses decreased $1.0 million mainly due to a $0.6 million increase in the level of corporate costs allocated to the corporation's operating companies and a $0.5 million reduction in labor costs due to a reduction in the number of corporate employees.

Corporate operating expenses decreased $0.2 million in 2016 as compared to 2015 as a result of decreased expenditures for contracted services and a decrease in claims at our captive insurance company, partially offset by a decrease in expenses allocated to OTP.

CONSOLIDATED INTEREST CHARGES

(in thousands)	2017	% change	2016	% change	2015
Interest Charges	$ 29,604	(7)	$ 31,886	2	$ 31,160

The $2.3 million decrease in interest charges in 2017 compared with 2016 is related to lower cost debt resulting from the issuance of $80.0 million of our 3.55% Guaranteed Senior Notes and the retirement of our remaining $52.3 million outstanding 9.000% Notes in December 2016 and the retirement of OTP's $33.0 million outstanding 5.95%, Series A Senior Unsecured Notes at maturity on August 20, 2017. The average level of debt outstanding between the periods increased by approximately $13.0 million with lower cost short-term debt being issued to retire higher cost long-term debt and being used to fund a portion of OTP's 2017 capital expenditures.

The $0.7 million increase in interest charges in 2016 compared with 2015 is due to an increase in interest expense on short-term debt at OTP as a result of a $24.7 million increase in OTP's daily average balance of short-term debt outstanding between the years and a $0.2 million decrease in capitalized interest expense. The increase in OTP's use of short-term borrowing is related to its increasing investment in two major MVP transmission line projects under construction.

CONSOLIDATED OTHER INCOME

(in thousands)	2017	% change	2016	% change	2015
Other Income	$ 2,632	(9)	$ 2,905	33	$ 2,177

Other income decreased $0.3 million in 2017 compared with 2016, mainly as a result of the receipt of $0.7 million in nontaxable corporate-owned life insurance proceeds in 2016 while no similar proceeds were received in 2017, offset by an increase in the cash surrender value of the life insurance policies in 2017 that was $0.3 million more than the increase in the cash surrender value in 2016.

The $0.7 million increase in other income in 2016 compared with 2015 is mainly due to proceeds from corporate-owned life insurance received in 2016.

CONSOLIDATED INCOME TAXES

Income tax expense - continuing operations was $27.0 million in 2017 compared with $20.1 million in 2016 and $21.6 million in 2015. Income tax expense increased $6.9 million in 2017 compared with 2016 mainly as a result of a $17.0 million increase in income from continuing operations before income taxes.

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The following table provides a reconciliation of income tax expense – continuing operations calculated at the federal statutory rate on income from continuing operations before income taxes reported on our consolidated statements of income:

(in thousands)	For the Year Ended December 31, 2017	2016	2015
Tax Computed at Federal Statutory Rate – Continuing Operations	$ 34,707	$ 28,741	$ 28,081
Increases (Decreases) in Tax from:			
Federal PTCs	(7,527)	(7,175)	(6,962)
State Income Taxes Net of Federal Income Tax Expense	4,341	2,848	4,945
Section 199 Domestic Production Activities Deduction	(1,471)	(482)	--
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(850)	(850)	(850)
Corporate-owned Life Insurance	(845)	(680)	(167)
Excess Tax deduction – Stock Compensation Awards	(751)	--	--
Employee Stock Ownership Plan Dividend Deduction	(509)	(537)	(560)
AFUDC - Equity	(322)	(280)	(426)
Investment Tax Credit Amortization	(164)	(350)	(571)
Differences Reversing in Excess of Federal Rates	551	77	(1,143)
Permanent and Other Differences	(1,873)	(1,231)	(705)
Effect of TCJA Tax Rate Reduction on Value of Net Deferred Tax Assets	1,756	--	--
Total Income Tax Expense – Continuing Operations	$ 27,043	$ 20,081	$ 21,642
Effective Income Tax Rate – Continuing Operations	27.3%	24.5%	27.0%

Federal PTCs are recognized as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP's kwh generation from its wind turbines eligible for PTCs increased 4.4% in 2017 compared with 2016 due to improved availability of the turbines and more favorable wind and operating conditions in 2017. OTP's kwh generation from its wind turbines eligible for PTCs increased 3.6% in 2016 compared with 2015 primarily due to higher average wind speed in 2016 compared with 2015. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

DISCONTINUED OPERATIONS

On April 30, 2015 we sold Foley Company (Foley) for $12.0 million in cash, plus $6.3 million in adjustments for working capital and other related items received in October 2015, less $1.0 million in selling expenses. On February 28, 2015 we sold the assets of AEV, Inc. for $22.3 million in cash, plus $0.6 million in adjustments for working capital and fixed assets received in October 2015, less $0.8 million in selling expenses. Foley and AEV, Inc were included in our Construction segment. On February 8, 2013 we completed the sale of substantially all the assets of our dock and boatlift company, formerly included in our Manufacturing segment. On November 30, 2012 we completed the sale of the assets of our wind tower manufacturing business, formerly included in our Wind Energy segment. Our Construction and Wind Energy segments were eliminated as a result of these sales.

The financial position, results of operations and cash flows of Foley, AEV, Inc., our wind tower manufacturing business and our dock and boatlift company are reported as discontinued operations in our consolidated financial statements. Following are the results of discontinued operations by entity for the years ended December 31, 2017, 2016 and 2015:

(in thousands)	Foley	AEV, Inc.	Wind Tower Business	Dock and Boatlift Business	Intercompany Transactions Adjustment	Total
2017 Net (Loss) Income	$ (140)	$ --	$ 276	$ 184	$ --	$ 320
2016 Net (Loss) Income	$ (114)	$ (5)	$ 454	$ (51)	$ --	$ 284
2015 Net (Loss) Income	$ (5,489)	$ 6,216	$ 344	$ (580)	$ 265	$ 756

Foley and AEV, Inc. entered into fixed-price construction contracts. Revenues under these contracts were recognized on a percentage-of-completion basis. The method used to determine the progress of completion was based on the ratio of costs incurred to total estimated costs on construction projects. An increase in estimated costs on one large job in progress at Foley in excess of previous period cost estimates resulted in pretax charges of $4.4 million in 2015.

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IMPACT OF INFLATION

OTP operates under regulatory provisions that allow price changes in fuel and certain purchased power costs to be passed to most retail customers through automatic adjustments to its rate schedules under fuel clause adjustments. Other increases in the cost of electric service must be recovered through timely filings for electric rate increases with the appropriate regulatory agency.

Our Manufacturing and Plastics segments consist entirely of businesses whose revenues are not subject to regulation by ratemaking authorities. Increased operating costs are reflected in product or services pricing with any limitations on price increases determined by the marketplace. Raw material costs, labor costs, fuel and energy costs and interest rates are important components of costs for companies in these segments. Any or all of these components could be impacted by inflation or other pricing pressures, with a possible adverse effect on our profitability, especially where increases in these costs exceed price increases on finished products. In recent years, our operating companies have faced strong inflationary and other pricing pressures with respect to steel, fuel, resin, and health care costs, which have been partially mitigated by pricing adjustments.

LIQUIDITY

The following table presents the status of our lines of credit as of December 31, 2017 and December 31, 2016:

(in thousands)	Line Limit	In Use on December 31, 2017	Restricted due to Outstanding Letters of Credit	Available on December 31, 2017	Available on December 31, 2016
Otter Tail Corporation Credit Agreement	$ 130,000	$ --	$ --	$ 130,000	$ 130,000
OTP Credit Agreement[1]	170,000	112,371	300	57,329	127,067
Total	$ 300,000	$ 112,371	$ 300	$ 187,329	$ 257,067

[1] *$100 million in outstanding borrowings under the OTP Credit Agreement were repaid on February 7, 2018 with proceeds from the issuance of $100 million of OTP's 4.07% Series 2018A Notes due February 7, 2048.*

We believe we have the necessary liquidity to effectively conduct business operations for an extended period if needed. Our balance sheet is strong and we are in compliance with our debt covenants. Financial flexibility is provided by operating cash flows, unused lines of credit, strong financial coverages, investment grade credit ratings and alternative financing arrangements such as leasing.

We believe our financial condition is strong and our cash, other liquid assets, operating cash flows, existing lines of credit, access to capital markets and borrowing ability because of investment-grade credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. On May 11, 2015 we filed a shelf registration statement with the Securities and Exchange Commission (SEC) under which we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement, which expires on May 11, 2018. On May 11, 2015, we entered into a Distribution Agreement with J.P. Morgan Securities LLC (JPMS) under which we may offer and sell our common shares from time to time through JPMS, as our distribution agent, up to an aggregate sales price of $75 million through an At-the-Market offering program. No shares were issued under this program in 2017.

Equity or debt financing will be required in the period 2018 through 2022 given the expansion plans related to our Electric segment to fund construction of new rate base investments. Also, such financing will be required should we decide to reduce borrowings under our lines of credit or refund or retire early any of our presently outstanding debt, to complete acquisitions or for other corporate purposes. Our operating cash flows and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by changing interest rates on short-term and long-term debt and ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

The determination of the amount of future cash dividends to be declared and paid will depend on, among other things, our financial condition, improvement in earnings per share, cash flows from operations, the level of our capital expenditures and our future business prospects. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by our subsidiaries. See note 7 to consolidated financial statements for more information. The decision to declare a dividend is reviewed quarterly by the board of directors. On February 5, 2018 our board of directors increased the quarterly dividend from $0.32 to $0.335 per common share.

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2017 Cash Flows Compared with 2016 Cash Flows

The $10.1 million increase in cash provided by continuing operations between the years includes a $10.1 million increase in net income from continuing operations, a $10.0 million reduction in discretionary contributions to our pension plan. Changes in long-term assets and liabilities, including deferred taxes, totaling $17.4 million were more than offset by a $27.0 million increase in cash used for working capital items. The increase in cash used for working capital between the periods is primarily due to a $19.1 million increase in cash used for payables and other current liabilities between the years at OTP related to the timing of payments as cash use decreased $10.3 million in 2016 compared to an increase of $8.8 million in cash used for payables and other current liabilities in 2017. Cash used for inventories increased $6.2 million between the years primarily due to increased levels of inventory in each of our business segments.

Net cash used in investing activities was $132.6 million in 2017 compared with $159.3 million in 2016. The $26.7 million decrease in cash used for investing activities includes a $28.3 million decrease in cash used for capital expenditures offset by $1.5 million in acquisition purchase price adjustments. The decrease in cash used for capital expenditures is mainly due to a $31.2 million reduction in cash used for capital expenditures at OTP as work concluded on the Big Stone South–Brookings 345 kV transmission line project which was energized in September 2017. Capital expenditures increased $2.8 million in our Manufacturing and Plastics segments.

Net cash used in financing activities was $24.8 million in 2017 compared with $4.1 million in 2016. Financing activities in 2017 included a $69.5 million increase in net short-term borrowings under OTP's credit agreement, of which $33.0 million was used to redeem OTP's 5.95% Senior Unsecured Series A Notes which matured on August 20, 2017. The additional short-term borrowings were used to fund a portion of OTP's 2017 capital expenditures. Operating cash flows from our Manufacturing and Plastic's segments were used to repay an additional $15.2 million in long-term debt related to those operations. Financing activities in 2017 also included $2.4 million from an increase in checks written in excess of cash and $4.3 million in net proceeds from the issuance of common stock under our automatic dividend reinvestment and share purchase plan, offset by $1.8 million in stock repurchases related to tax withholding requirements for stock incentive awards. See note 5 to the Company's consolidated financial statements for further information on stock issuances and retirements in 2017. We paid common stock dividends of $50.6 million in 2017 compared with $48.2 million in 2016.

2016 Cash Flows Compared with 2015 Cash Flows

Cash provided by operating activities of continuing operations was $163.5 million in 2016 compared with $131.5 million in 2015. The $32.0 million increase in cash provided by continuing operations between the years includes a $32.8 million reduction in cash used for working capital items due to:

- An $18.2 million decrease in cash used for accounts payable and other current liabilities at OTP, reflecting higher levels of payables in December 2016 for coal deliveries and transmission services related to the colder temperatures in December 2016 and the payment, in January 2015, of large billings for coal transportation, coal and power purchased in December 2014.
- A $10.7 million decrease in cash used for accounts payable and other current liabilities at the plastic pipe companies related to an increase in year-end resin purchases in 2016 compared to 2015.
- A $7.3 million decrease in cash used for interest payable and income taxes receivable between the years, mainly related to having made a $4.0 million estimated tax payment in December 2015 that was refunded in the first quarter of 2016, as a five-year extension of bonus depreciation for income taxes, approved on December 18, 2015, resulted in a lower federal income tax liability for the Company in 2015.

offset by:

- A $2.3 million increase in unbilled revenues at OTP between the years resulting from the 2016 increase in interim rates in Minnesota and increased kwh sales due to colder weather in December 2016 compared with December 2015.

In continuing operations, net cash used in investing activities was $159.3 million in 2016 compared with $193.6 million in 2015. The $34.3 million decrease in cash used for investing activities includes a $32.3 million decrease in cash used in acquisitions as we paid $30.8 million to acquire the assets of BTD-Georgia in September 2015 and received a purchase price adjustment of $1.5 million in June 2016.

Net cash used in financing activities of continuing operations was $4.1 million in 2016 compared with net cash provided by financing activities of $38.1 million in 2015. Financing activities in 2016 included:

- $80.0 million in proceeds from the issuance of our 3.55% Guaranteed Senior Notes due December 15, 2026 in December 2016.
- $50.0 million borrowed under our term loan agreement in February 2016.

- $32.8 million in net proceeds from the issuance of 1,014,115 shares of common stock under the Company's At-the-Market offering program.

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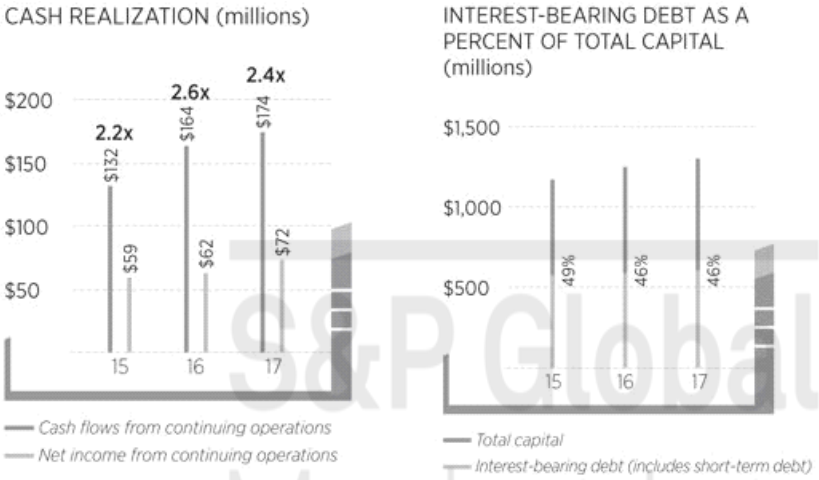
- $11.1 million in net proceeds from the issuance of 356,399 shares of common stock under the Company's automatic dividend reinvestment and share purchase plan.

offset by:

- The repayment of the $52.3 million balance of our 9.000% notes due in December 2016.
- A $41.2 million reduction of short-term borrowings and checks written in excess of cash.
- The repayment of $35.0 million of funds borrowed in February 2016 under our term loan agreement.
- $48.2 million in common stock dividend payments.

The outstanding short-term borrowings that were paid down were, in part, used to fund the expansion of BTD's Minnesota facilities in 2015 and the September 1, 2015 acquisition of BTD-Georgia.



CAPITAL REQUIREMENTS

Capital Expenditures

We have a capital expenditure program for expanding, upgrading and improving our plants and operating equipment. Typical uses of cash for capital expenditures are investments in electric generation facilities and environmental upgrades, transmission and distribution lines, manufacturing facilities and upgrades, equipment used in the manufacturing process, and computer hardware and information systems. The capital expenditure program is subject to review and is revised in light of changes in demands for energy, technology, environmental laws, regulatory changes, business expansion opportunities, the costs of labor, materials and equipment and our consolidated financial condition.

Cash used for consolidated capital expenditures was $132.9 million in 2017, $161.3 million in 2016 and $160 million in 2015. Estimated capital expenditures for 2018 are $110 million. Total capital expenditures for the five-year period 2018 through 2022 are estimated to be approximately $973 million, including:

- $302 million for renewable wind and solar energy generation projects.
- $161 million for natural gas-fired generation to replace Hoot Lake Plant capacity.
- $136 million for numerous potential technology and infrastructure projects to transform future operations, including automated metering, telecommunications, geographic information systems, work and asset management systems, financial information systems, system infrastructure reliability improvements, outage management systems, and storage projects.
- $35 million for OTP's Big Stone South–Ellendale 345 kV transmission line project.

The breakdown of 2015, 2016 and 2017 actual cash used for capital expenditures and 2018 through 2022 estimated capital expenditures by segment is as follows:

(in millions)	2015	2016	2017	2018	2019	2020	2021	2022	2018-2022
Electric	$ 136	$ 150	$ 119	$ 95	$ 382	$ 185	$ 145	$ 94	$ 901
Manufacturing	20	8	10	11	10	11	10	11	53
Plastics	4	3	4	4	4	4	4	3	19
Total	$ 160	$ 161	$ 133	$ 110	$ 396	$ 200	$ 159	$ 108	$ 973

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On November 16, 2016 OTP entered into an Asset Purchase Agreement (the Purchase Agreement) with EDF Renewable Development, Inc. and certain of its affiliated companies (EDF) to purchase and assume the development assets associated with a 150-MW wind farm in southeastern North Dakota (the Merricourt Project) for a purchase price of $34.7 million, subject to adjustments for interconnection costs. The Purchase Agreement is currently expected to close no earlier than mid-2018, pending regulatory reviews, satisfactory interconnection costs and other conditions. On the same day, OTP entered into a Turnkey Engineering, Procurement and Construction Services Agreement with EDF that will be effective upon the closing of the Purchase Agreement pursuant to which EDF will construct the wind farm with a targeted completion date in

2019 for consideration of $200.5 million, subject to certain adjustments, payable following the closing of the Purchase Agreement in installments in connection with certain project construction milestones. The agreements contain representations, warranties, covenants and indemnities customary to transactions of this type and include provisions for liquidated damages to be paid by EDF in the event of certain occurrences described in the agreements. As of December 31, 2017 OTP had capitalized approximately $4.5 million in development costs associated with the Merricourt Project. On April 10, 2017 OTP submitted an application for Advance Determination of Prudence (ADP) and Certificate of Public Convenience and Necessity to the North Dakota Public Service Commission (NDPSC) for the Merricourt Project. A final order for the ADP, subject to qualifications and compliance obligations, and the Certificate of Public Convenience and Necessity was issued by the NDPSC on November 3, 2017. On October 26, 2017 the MNPUC approved the facility under the Renewable Energy Standard making the project eligible for cost recovery under the Minnesota Renewable Resource Recovery rider.

In addition to initiation of the Merricourt Project, OTP is moving forward with plans for the development, construction and ownership of a 250-MW simple-cycle natural gas-fired combustion turbine generation facility near Astoria, South Dakota (Astoria Station) as part of its plan to reliably meet customers' electric needs, replace expiring capacity purchase agreements and prepare for the planned retirement of its Hoot Lake Plant in 2021. OTP expects the project will cost approximately $165 million. As of December 31, 2017 OTP had capitalized approximately $3.8 million in development costs associated with Astoria Station. On April 10, 2017 OTP also submitted an application for ADP to the NDPSC for the Astoria Station. A final order for the ADP for Astoria Station was issued by the NDPSC on November 3, 2017, subject to certain qualifications and compliance obligations.

If a resource addition is determined to be prudent by the NDPSC, a public utility may recover in its rates for North Dakota customers, and in a timely manner consistent with the public utility's financial obligations, the jurisdictional share of amounts the public utility reasonably incurred or obligated on a prudent resource addition, including accrued allowance for funds used during construction, even though the resource addition may never be fully operational or used by the public utility to serve its North Dakota customers. The cost amortization period for a discontinued resource addition may not exceed five years from the date commencement of the recovery is approved by the NDPSC. No return on amounts incurred or obligated by the public utility may be authorized for the period after the resource addition is discontinued.

Contractual Obligations

The following table summarizes our contractual obligations at December 31, 2017, plus our debt and interest obligations on the $100 million in debt OTP issued on February 7, 2018, and the effect these obligations are expected to have on our liquidity and cash flow in future periods.

(in millions)	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Coal Contracts (required minimums)	$ 644	$ 26	$ 45	$ 45	$ 528
Debt Obligations	593	--	--	171	422
Interest on Debt Obligations	433	29	58	51	295
Capacity and Energy Requirements	253	24	50	25	154
Postretirement Benefit Obligations	112	6	11	12	83
Other Purchase Obligations	48	29	17	2	--
Operating Lease Obligations	34	6	10	5	13
Total Contractual Cash Obligations	$ 2,117	$ 120	$ 191	$ 311	$ 1,495

Postretirement Benefit Obligations include estimated cash expenditures for the payment of retiree medical and life insurance benefits and supplemental pension benefits under our unfunded Executive Survivor and Supplemental Retirement Plan, but do not include amounts to fund our noncontributory funded pension plan, as we are not currently required to make a contribution to that plan.

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S&P Global Market Intelligence

CAPITAL RESOURCES

Financial flexibility is provided by operating cash flows, unused lines of credit, strong financial coverages, investment grade credit ratings, and alternative financing arrangements such as leasing. Equity or debt financing will be required in the period 2018 through 2022 given the expansion plans related to our Electric segment to fund construction of new rate base and transmission investments, in the event we decide to reduce borrowings under our lines of credit, to refund or retire early any of our presently outstanding debt, to complete acquisitions or for other corporate purposes. There can be no assurance that any additional required financing will be available through bank borrowings, debt or equity financing or otherwise, or that if such financing is available, it will be available on terms acceptable to us. If adequate funds are not available on acceptable terms, our businesses, results of operations and financial condition could be adversely affected.

Under our shelf registration statement filed with the SEC we may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement, until May 11, 2018.

Under our At-the-Market offering program, we may offer and sell our common shares from time to time until May 11, 2018 through JPMS, as our distribution agent, up to an aggregate sales price of $75 million, of which $39.2 million remained available at December 31, 2017. Under the Distribution Agreement with JPMS, we will designate the minimum price and maximum number of shares to be sold through JPMS on any given trading day or over a specified period of trading days, and JPMS will use commercially reasonable efforts to sell such shares on such days, subject to certain conditions. We are not obligated to sell and JPMS is not obligated to buy or sell any of the shares under the Agreement.

Short-Term Debt

The following table presents the status of our lines of credit as of December 31, 2017 and December 31, 2016:

(in thousands)	Line Limit	In Use on December 31, 2017	Restricted due to Outstanding Letters of Credit	Available on December 31, 2017	Available on December 31, 2016
Otter Tail Corporation Credit Agreement	$ 130,000	$ --	$ --	$ 130,000	$ 130,000
OTP Credit Agreement[1]	170,000	112,371	300	57,329	127,067
Total	$ 300,000	$ 112,371	$ 300	$ 187,329	$ 257,067

[1] *$100 million in outstanding borrowings under the OTP Credit Agreement were repaid on February 7, 2018 with proceeds from the issuance of $100 million of OTP's 4.07% Series 2018A Notes due February 7, 2048.*

Under the Otter Tail Corporation Credit Agreement (as defined below), the maximum amount of debt outstanding in 2017 was $15,169,000 on April 3, 2017 and the average daily balance of debt outstanding during 2017 was $2,305,000. The weighted average interest rate paid on debt outstanding under the Otter Tail Corporation Credit Agreement

during 2017 was 2.8% compared with 2.3% in 2016. Under the OTP Credit Agreement (as defined below), the maximum amount of debt outstanding in 2017 was $112,371,000 from December 29-31, 2017 and the average daily balance of debt outstanding during 2017 was $69,391,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2017 was 2.4% compared with 1.8% in 2016. The maximum amount of consolidated short-term debt outstanding in 2017 was $112,371,000 from December 29-31, 2017 and the average daily balance of consolidated short-term debt outstanding during 2017 was $71,696,000. The weighted average interest rate on consolidated short-term debt outstanding on December 31, 2017 was 2.7%.

On October 29, 2012 we entered into a Third Amended and Restated Credit Agreement (the Otter Tail Corporation Credit Agreement), which is an unsecured $130 million revolving credit facility that may be increased to $250 million on the terms and subject to the conditions described in the Otter Tail Corporation Credit Agreement. On October 31, 2017 the Otter Tail Corporation Credit Agreement was amended to extend its expiration date by one year from October 29, 2021 to October 31, 2022. We can draw on this credit facility to refinance certain indebtedness and support our operations and the operations of certain of our subsidiaries. Borrowings under the Otter Tail Corporation Credit Agreement bear interest at LIBOR plus 1.50%, subject to adjustment based on our senior unsecured credit ratings or the issuer rating if a rating is not provided for the senior unsecured credit. We are required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The Otter Tail Corporation Credit Agreement contains a number of restrictions on us and the businesses of our wholly owned subsidiary, Varistar Corporation (Varistar) and its subsidiaries, including restrictions on our and their ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Otter Tail Corporation Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading “Financial Covenants.” The Otter Tail Corporation Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Our obligations under the Otter Tail Corporation Credit Agreement are guaranteed by certain of our subsidiaries. Outstanding letters of credit issued by us under the Otter Tail Corporation Credit Agreement can reduce the amount available for borrowing under the line by up to $40 million.

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On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement), providing for an unsecured $170 million revolving credit facility that may be increased to $250 million on the terms and subject to the conditions described in the OTP Credit Agreement. On October 31, 2017 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2021 to October 31, 2022. OTP can draw on this credit facility to support the working capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed $50 million outstanding at any time. Borrowings under this line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on the ratings of OTP’s senior unsecured debt or the issuer rating if a rating is not provided for the senior unsecured debt. OTP is required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading “Financial Covenants.” The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP’s credit ratings. OTP’s obligations under the OTP Credit Agreement are not guaranteed by any other party.

Long-Term Debt

2018 Note Purchase Agreement

On November 14, 2017, OTP entered into a Note Purchase Agreement (the 2018 Note Purchase Agreement) with the purchasers named therein, pursuant to which OTP agreed to issue to the purchasers, in a private placement transaction, $100 million aggregate principal amount of OTP’s 4.07% Series 2018A Senior Unsecured Notes due February 7, 2048 (the 2018 Notes). The 2018 Notes were issued on February 7, 2018. Proceeds from the 2018 Notes were used to repay $100 million in outstanding borrowings under the OTP Credit Agreement.

OTP may prepay all or any part of the 2018 Notes (in an amount not less than 10% of the aggregate principal amount of the Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount so prepaid, together with unpaid accrued interest and a make-whole amount; provided that if no default or event of default exists under the 2018 Note Purchase Agreement, any prepayment made by OTP of all of the 2018 Notes then outstanding on or after August 7, 2047 will be made without any make-whole amount. The 2018 Note Purchase Agreement also requires OTP to offer to prepay all outstanding 2018 Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2018 Note Purchase Agreement) of OTP.

The 2018 Note Purchase Agreement contains a number of restrictions on the business of OTP. These include restrictions on OTP’s abilities to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The 2018 Note Purchase Agreement also contains other negative covenants and events of default, as well as certain financial covenants as described below under the heading “Financial Covenants.” The 2018 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP’s credit ratings. The 2018 Note Purchase Agreement includes a “most favored lender” provision generally requiring that in the event the OTP Credit Agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2018 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the 2018 Notes than any analogous provision contained in the 2018 Note Purchase Agreement (an Additional Covenant), then unless waived by the Required Holders (as defined in the 2018 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2018 Note Purchase Agreement. The 2018 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP Credit Agreement, provided that no default or event of default has occurred and is continuing.

2016 Note Purchase Agreement

On September 23, 2016 we entered into a Note Purchase Agreement (the 2016 Note Purchase Agreement) with the purchasers named therein, pursuant to which we agreed to issue to the purchasers, in a private placement transaction, $80 million aggregate principal amount of our 3.55% Guaranteed Senior Notes due December 15, 2026 (the 2026 Notes). The 2026 Notes were issued on December 13, 2016. Our obligations under the 2016 Note Purchase Agreement and the 2026 Notes are guaranteed by our Material Subsidiaries (as defined in the 2016 Note Purchase Agreement, but specifically excluding OTP). The proceeds from the issuance of the 2026 Notes were used to repay the remaining $52,330,000 of our 9.000% Senior Notes due December 15, 2016, and to pay down a portion of the $50 million in funds borrowed in February 2016 under our Term Loan Agreement described below.

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We may prepay all or any part of the 2026 Notes (in an amount not less than 10% of the aggregate principal amount of the 2026 Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with unpaid accrued interest and a make-whole amount; provided that if no default or event of default exists under the 2016 Note Purchase Agreement, any optional prepayment made by us of all of the 2026 Notes on or after September 15, 2026 will bemade without any make-whole amount. We are required to offer to prepay all of the outstanding 2026 Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2016 Note Purchase Agreement) of the Company. In addition, if we and our Material Subsidiaries sell a “substantial part” of our or their assets and use the proceeds to prepay or retire senior Interest-bearing Debt (as defined in the 2016 Note Purchase Agreement) of the Company and/or a Material Subsidiary in

accordance with the terms of the 2016 Note Purchase Agreement, we are required to offer to prepay a Ratable Portion (as defined in the 2016 Note Purchase Agreement) of the 2026 Notes held by each holder of the 2026 Notes.

The 2016 Note Purchase Agreement contains a number of restrictions on the business of the Company and our Material Subsidiaries. These include restrictions on our and our Material Subsidiaries' abilities to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, engage in transactions with related parties, redeem or pay dividends on our and our Material Subsidiaries' shares of capital stock, and make investments. The 2016 Note Purchase Agreement also contains other negative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2016 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our or our Material Subsidiaries' credit ratings.

Term Loan Agreement

On February 5, 2016 we borrowed $50 million under an unsecured Term Loan Agreement (the Term Loan Agreement) at an interest rate based on the 30 day LIBOR plus 90 basis points. The proceeds from the Term Loan Agreement were used to pay down borrowings under the Otter Tail Corporation Credit Agreement that were used to fund the expansion of BTD's Minnesota facilities in 2015 and to fund the September 1, 2015 acquisition of BTD-Georgia. We repaid $35 million of the $50 million in the fourth quarter of 2016 and we repaid the remaining $15 million during 2017. The Term Loan Agreement terminated on February 5, 2018.

2013 Note Purchase Agreement

On August 14, 2013 OTP entered into a Note Purchase Agreement (the 2013 Note Purchase Agreement) with the purchasers named therein, pursuant to which OTP agreed to issue to the purchasers, in a private placement transaction, $60 million aggregate principal amount of OTP's 4.68% Series A Senior Unsecured Notes due February 27, 2029 (the Series A Notes) and $90 million aggregate principal amount of OTP's 5.47% Series B Senior Unsecured Notes due February 27, 2044 (the Series B Notes and, together with the Series A Notes, the Notes). The notes were issued on February 27, 2014.

The 2013 Note Purchase Agreement states that OTP may prepay all or any part of the Notes (in an amount not less than 10% of the aggregate principal amount of the Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount, provided that if no default or event of default under the 2013 Note Purchase Agreement exists, any optional prepayment made by OTP of (i) all of the Series A Notes then outstanding on or after November 27, 2028 or (ii) all of the Series B Notes then outstanding on or after November 27, 2043, will be made at 100% of the principal prepaid but without any make-whole amount. In addition, the 2013 Note Purchase Agreement states OTP must offer to prepay all of the outstanding Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2013 Note Purchase Agreement) of OTP.

The 2013 Note Purchase Agreement contains a number of restrictions on the business of OTP, including restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The 2013 Note Purchase Agreement also contains affirmative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2013 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The 2013 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event the OTP Credit Agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2013 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the Notes than any analogous provision contained in the 2013 Note Purchase Agreement (an Additional Covenant), then unless waived by the Required Holders (as defined in the 2013 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2013 Note Purchase Agreement. The 2013 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP credit agreement, provided that no default or event of default has occurred and is continuing.

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2007 and 2011 Note Purchase Agreements

On December 1, 2011, OTP issued $140 million aggregate principal amount of its 4.63% Senior Unsecured Notes due December 1, 2021 pursuant to a Note Purchase Agreement dated as of July 29, 2011 (the 2011 Note Purchase Agreement). OTP also has outstanding its $122 million senior unsecured notes issued in three series consisting of $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (collectively, the 2007 Notes). The 2007 Notes were issued pursuant to a Note Purchase Agreement dated as of August 20, 2007 (the 2007 Note Purchase Agreement). On August 21, 2017 OTP used borrowings under the OTP Credit Agreement to retire its $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, which had been issued under the 2007 Note Purchase Agreement and matured on August 20, 2017.

The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each states that OTP may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. The 2011 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require OTP to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the 2011 Note Purchase Agreement. The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each also states that OTP must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP. The note purchase agreements contain a number of restrictions on OTP, including restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The note purchase agreements also include affirmative covenants and events of default, and certain financial covenants as described below under the heading "Financial Covenants."

Financial Covenants

We were in compliance with the financial covenants in our debt agreements as of December 31, 2017.

No Credit or Note Purchase Agreement contains any provisions that would trigger an acceleration of the related debt as a result of changes in the credit rating levels assigned to the related obligor by rating agencies.

Our borrowing agreements are subject to certain financial covenants. Specifically:

- Under the Otter Tail Corporation Credit Agreement and the 2016 Note Purchase Agreement, we may not permit the ratio of our Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit our Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis). As of December 31, 2017 our Interest and Dividend Coverage Ratio calculated under the requirements of the Otter Tail Corporation Credit Agreement and the 2016 Note Purchase Agreement was 4.47 to 1.00.

- Under the 2016 Note Purchase Agreement, we may not permit our Priority Indebtedness to exceed 10% of our Total Capitalization.

- Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00.

- Under the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, OTP may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, in each case as provided in the related borrowing agreement, and OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement. As of December 31, 2017 OTP's Interest and Dividend Coverage Ratio and Interest Charges Coverage Ratio, calculated under the requirements of the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, was 3.62 to 1.00.

- Under the 2013 Note Purchase Agreement and the 2018 Note Purchase Agreement, OTP may not permit its Interest-bearing Debt to exceed 60% of Total Capitalization and may not permit its Priority Indebtedness to exceed 20% of its Total Capitalization, in each case as provided in the related agreement.

As of December 31, 2017 our ratio of Interest-bearing Debt to Total Capitalization was 0.46 to 1.00 on a consolidated basis and 0.49 to 1.00 for OTP. Neither Otter Tail Corporation nor OTP had any Priority Indebtedness outstanding as of December 31, 2017.

Our ratio of earnings to fixed charges from continuing operations reported in Exhibit 12.1 to this Annual Report on Form 10-K, which includes imputed finance costs on operating leases, was 4.1x for 2017 and 3.4x for 2016. During 2018, we expect this coverage ratio to increase, assuming 2018 net income meets our expectations.

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OFF-BALANCE-SHEET ARRANGEMENTS

We and our subsidiary companies have outstanding letters of credit totaling $3.9 million, but our line of credit borrowing limits are only restricted by $0.3 million in outstanding letters of credit. We do not have any other off-balance-sheet arrangements or any relationships with unconsolidated entities or financial partnerships. These entities are often referred to as structured finance special purpose entities or variable interest entities, which are established for the purpose of facilitating off-balance-sheet arrangements or for other contractually narrow or limited purposes. We are not exposed to any financing, liquidity, market or credit risk that could arise if we had such relationships.

2018 BUSINESS OUTLOOK

We anticipate 2018 diluted earnings per share to be in the range of $1.80 to $1.95. This guidance reflects the current mix of businesses we own, strategies for improving future operating results, the cyclical nature of some of our businesses, and current regulatory factors and economic challenges facing our Electric, Manufacturing and Plastics segments. Due to the tax rate reduction in the TCJA, we expect 2018 earnings for our Manufacturing and Plastics segments to be positively impacted by $0.09 per share offset by $0.04 per share in our corporate cost center. We expect capital expenditures for 2018 to be $110 million compared with actual cash used for capital expenditures of $133 million in 2017. Our planned expenditures for 2018 include $33 million for the Big Stone South–Ellendale transmission line project, which positively impacts earnings by providing an immediate return on invested funds through rider recovery mechanisms.

Segment components of our 2018 earnings per share guidance range compared with 2017 actual earnings are as follows:

	2017 EPS by Segment			2018 EPS Guidance	
	GAAP-Basis	Impact of Tax Reform	*Before Impact of Tax Reform*[1]	Low	High
Electric	$ 1.24	$ 0.02	$ 1.26	$ 1.34	$ 1.37
Manufacturing	$ 0.28	$ (0.07)	$ 0.21	$ 0.26	$ 0.30
Plastics	$ 0.54	$ (0.08)	$ 0.46	$ 0.36	$ 0.40
Corporate	$ (0.25)	$ 0.18	$ (0.07)	$ (0.16)	$ (0.12)
Total – Continuing Operations	$ 1.81	$ 0.05	$ 1.86	$ 1.80	$ 1.95
Return on Equity	10.6%		10.8%	10.1%	10.9%

1 This table includes measures of financial performance and presentations of financial information that are not defined by generally accepted accounting principles (GAAP). Management believes that presenting diluted earnings per share from continuing operations by segment and in total on a Non-GAAP basis by excluding the impact of the TCJA tax rate reduction on deferred tax values will assist investors in making an evaluation of our performance against expectations for 2018 on a comparable basis. Management understands that there are material limitations on the use of non-GAAP measures. Non-GAAP measures are not substitutes for GAAP measures for the purpose of analyzing financial performance. These non-GAAP measures are not in accordance with, or an alternative for, measures prepared in accordance with generally accepted accounting principles and may be different from non-GAAP measures used by other companies. In addition, these non-GAAP measures are not based on any comprehensive set of accounting rules or principles. This information should not be construed as an alternative to the reported results, which have been determined and provided in accordance with GAAP.

Contributing to our earnings guidance for 2018 are the following items:

- We expect 2018 Electric segment net income to be higher than 2017 segment net income based on:
  - Normal weather for 2018. Milder than normal weather in 2017 negatively impacted diluted earnings per share by an estimated $0.04 compared to normal.
  - Constructive outcome of a rate case filed in North Dakota on November 2, 2017 with a full year of increased interim rates in 2018. Our ability to obtain final rates similar to interim rates and reasonable rates of return depends on regulatory action under applicable statutes and regulations. We expect the effects of any reduction in interim or final rates as a result of lower tax rates in the TCJA to be offset by lower tax expenses. We cannot provide assurance our interim rates will become final.
  - Increase in transmission investments and other revenues.

offset by:

  - Increased operating and maintenance expenses due to a planned maintenance outage at our Big Stone Plant of $0.05 per share and $0.09 for increasing costs of pension, medical, workers compensation and retiree medical benefits. The increase in pension costs is a result of a decrease in the discount rate from 4.60% to 3.90%.

- Higher depreciation and property tax expense due to large capital projects being put into service.
- Increased interest expense related to replacing short-term debt at an average annual rate of 2.4% with long-term debt at a rate of 4.07% along with an increase in combined short-term and long-term borrowings to finance a portion of 2018 planned capital expenditures.

- We expect 2018 net income from our Manufacturing segment to increase over 2017 based on the following:
  - Sales at BTD are expected to be flat year-over-year however, earnings are expected to improve based on stronger year-over-year operating margins achieved through cost reductions and improved productivity.
  - An increase in earnings from T.O. Plastics mainly driven by year-over-year sales growth in horticulture, life science and industrial markets.
  - Lower income taxes of approximately $0.04 per share as a result of the lower federal tax rates implemented as part of the TCJA.
  - Backlog for the manufacturing companies of approximately $166 million for 2018 compared with $118 million one year ago.
- We expect 2018 net income from the Plastics segment to be lower than 2017, because 2017 results included sales driven by customer reaction to the hurricanes that occurred in the Gulf of Mexico. This had an estimated impact on earnings of $0.09 per diluted share in 2017. We also expect lower operating margins in 2018 due to a lower expected sales prices and increasing resin prices on similar sales volumes in 2018 compared to 2017 excluding the effect of the hurricanes on 2017 sales. Plastics net income for 2018 will be positively affected by lower effective tax rates in 2018 as a result of the TCJA.
- Corporate costs, net of tax, are expected to be higher in 2018 than in 2017 when excluding the effect of the TCJA on 2017 net losses in the corporate cost center. The higher net-of-tax costs expected in 2018 are due, in part, to the lower tax rate that will be in effect in 2018.

The impact of the TCJA on future results are based on reasonable estimates reflecting the anticipated impact of the TCJA, and are subject to adjustment upon obtaining additional information or to reflect future changes resulting from future legislation, rules, regulations or interpretations impacting the TCJA. The Company will continue to analyze the impact of the TCJA to assess the full effects on the Company's future business and results.

The following table shows our 2017 capital expenditures and 2018 through 2022 anticipated capital expenditures and electric utility average rate base:

(in millions)	2017	2018	2019	2020	2021	2022	Total
Capital Expenditures:							
Electric Segment:							
Renewables and Natural Gas Generation		$ 1	$ 308	$ 102	$ 50	$ 1	$ 462
Transformative Technology and Infrastructure		--	22	32	43	39	136
Transmission		45	12	9	7	7	80
Other		49	40	42	45	47	223
Total Electric Segment	$ 119	$ 95	$ 382	$ 185	$ 145	$ 94	$ 901
Manufacturing and Plastics Segments	14	15	14	15	14	14	72
Total Capital Expenditures	**$ 133**	**$ 110**	**$ 396**	**$ 200**	**$ 159**	**$ 108**	**$ 973**
Total Electric Utility Average Rate Base	**$ 1,055**	**$ 1,091**	**$ 1,297**	**$ 1,480**	**$ 1,568**	**$ 1,625**	

The consolidated capital expenditure plan for the 2018-2022 time period calls for $973 million based on the need for additional wind and solar in rate base and capital spending for Astoria Station, a natural gas-fired plant that is expected to replace Hoot Lake Plant when it is retired in 2021. Given the increased capital expenditure plan, our compounded annual growth rate in rate base is projected to be 9.0% from 2017 through 2022.

Execution on the currently anticipated electric utility capital expenditure plan is expected to grow rate base and be a key driver in increasing utility earnings over the 2018 through 2022 timeframe.

Our outlook for 2018 is dependent on a variety of factors and is subject to the risks and uncertainties discussed in Item 1A. Risk Factors, and elsewhere in this Annual Report on Form 10-K.

CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

Our significant accounting policies are described in note 1 to our consolidated financial statements. The discussion and analysis of the financial statements and results of operations are based on our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities.

We use estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric revenues, interim rate refunds, warranty reserves and actuarially determined benefits costs and liabilities. As better information becomes available or actual amounts are known, estimates are revised. Operating results can be affected by revised estimates. Actual results may differ from these estimates under different assumptions or conditions. Management has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of the board of directors. The following critical accounting policies affect the more significant judgments and estimates used in the preparation of our consolidated financial statements.

PENSION AND OTHER POSTRETIREMENT BENEFITS OBLIGATIONS AND COSTS

Pension and postretirement benefit liabilities and expenses for our electric utility and corporate employees are determined by actuaries using assumptions about the discount rate, expected return on plan assets, rate of compensation increase and healthcare cost-trend rates. Further discussion of our pension and postretirement benefit plans and related assumptions is included in note 10 to our consolidated financial statements.

These benefits, for any individual employee, can be earned and related expenses can be recognized and a liability accrued over periods of up to 35 or more years. These benefits can be paid out for up to 40 or more years after an employee retires. Estimates of liabilities and expenses related to these benefits are among our most critical

accounting estimates. Although deferral and amortization of fluctuations in actuarially determined benefit obligations and expenses are provided for when actual results on a year-to-year basis deviate from long-range assumptions, compensation increases and healthcare cost increases or a reduction in the discount rate applied from one year to the next can significantly increase our benefit expenses in the year of the change. Also, a reduction in the expected rate of return on pension plan assets in our funded pension plan or realized rates of return on plan assets that are well below assumed rates of return or an increase in the anticipated life expectancy of plan participants could result in significant increases in recognized pension benefit expenses in the year of the change or for many years thereafter because actuarial losses can be amortized over the average remaining service lives of active employees.

The pension benefit cost for 2018 for our noncontributory funded pension plan is expected to be $6.6 million compared to $5.9 million in 2017, reflecting a decrease in the estimated discount rate used to determine annual benefit cost accruals from 4.60% in 2017 to 3.90% in 2018. The assumed rate of return on pension plan assets will remain at 7.50% in 2018. In selecting the discount rate, we consider the yields of fixed income debt securities, which have ratings of “Aa” published by recognized rating agencies, along with bond matching models specific to our plan’s cash flows as a basis to determine the rate.

Subsequent increases or decreases in actual rates of return on plan assets over assumed rates or increases or decreases in the discount rate or rate of increase in future compensation levels could significantly change projected costs. For 2017, all other factors being held constant: a 0.25 increase in the discount rate would have decreased our 2017 pension benefit cost by $904,000; a 0.25 decrease in the discount rate would have increased our 2017 pension benefit cost by $950,000; a 0.25 increase in the assumed rate of increase in future compensation levels would have increased our 2017 pension benefit cost by $555,000; a 0.25 decrease in the assumed rate of increase in future compensation levels would have decreased our 2017 pension benefit cost by $543,000; and a 0.25 increase (or decrease) in the expected long-term rate of return on plan assets would have decreased (or increased) our 2017 pension benefit cost by $641,000.

Increases or decreases in the discount rate or in retiree healthcare cost inflation rates could significantly change our projected postretirement healthcare benefit costs. A 0.25 increase in the discount rate would have decreased our 2017 postretirement medical benefit costs by $217,000. A 0.25 decrease in the discount rate would have increased our 2017 postretirement medical benefit costs by $228,000. See note 10 to consolidated financial statements for the cost impact of a change in medical cost inflation rates.

We believe the estimates made for our pension and other postretirement benefits are reasonable based on the information that is known at the point in time the estimates are made. These estimates and assumptions are subject to a number of variables and are subject to change.

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TAXATION

We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and use taxes. These judgments could result in the recognition of a liability for potential adverse outcomes regarding uncertain tax positions that we have taken. While we believe our liability for uncertain tax positions as of December 31, 2017 reflects the most likely probable expected outcome of these tax matters in accordance with the requirements of ASC Topic 740, *Income Taxes*, the ultimate outcome of such matters could result in additional adjustments to our consolidated financial statements. However, we do not believe such adjustments would be material.

Deferred income taxes are provided for revenue and expenses which are recognized in different periods for income tax and financial reporting purposes. We assess our deferred tax assets for recoverability taking into consideration our historical and anticipated earnings levels, the reversal of other existing temporary differences, available net operating loss carryforwards and available tax planning strategies that could be implemented to realize the deferred tax assets. Based on this assessment, management must evaluate the need for, and amount of, a valuation allowance against our deferred tax assets. As facts and circumstances change, adjustments to the valuation allowance may be required.

ASSET IMPAIRMENT

We are required to test for asset impairment relating to property and equipment whenever events or changes in circumstances indicate that the carrying amount of a long-lived asset may exceed its fair value and not be recoverable. We apply the accounting guidance under ASC 360-10-35, *Property, Plant, and Equipment – Subsequent Measurement*, in order to determine whether or not an asset is impaired. This standard requires an impairment analysis when indicators of impairment are present. If such indicators are present, the standard requires that if the sum of the future expected cash flows from a company’s asset, undiscounted and without interest charges, is less than the carrying amount, an asset impairment must be recognized in the financial statements. The amount of the impairment is the difference between the fair value of the asset and the carrying amount of the asset.

We believe the accounting estimates related to an asset impairment are critical because: (1) they are highly susceptible to change from period to period, reflecting changing business cycles, (2) they require management to make assumptions about future cash flows over future years, and (3) the impact of recognizing an impairment could have a significant effect on operations. Management’s assumptions about future cash flows require significant judgment because actual operating levels have fluctuated in the past and are expected to continue to do so in the future.

As of December 31, 2017 an assessment of the carrying amounts of our long-lived assets and other intangibles indicated these assets were not impaired.

GOODWILL IMPAIRMENT

Goodwill is required to be evaluated annually for impairment, according to ASC 350-20-35, *Goodwill – Subsequent Measurement*. We perform qualitative assessments of goodwill impairment and quantitative goodwill impairment testing annually in the fourth quarter. In addition, the quantitative testing is performed on an interim basis whenever events or circumstances indicate that the carrying amount of goodwill may not be recoverable. Examples of such events or circumstances may include a significant adverse change in business climate, weakness in an industry in which our reporting units operate or recent significant cash or operating losses with expectations that those losses will continue.

Under GAAP, we have the option of first performing a qualitative assessment to test goodwill for impairment on a reporting unit basis. If, after applying the qualitative assessment, we conclude that it is *not* more likely than not that the fair value of the reporting unit is less than its carrying value, the quantitative goodwill impairment test is not required. If, after performing the qualitative assessment, we conclude that it is more likely than not that the fair value of the reporting unit is less than its carrying value, we would perform the quantitative goodwill impairment test.

The quantitative goodwill impairment test is a two-step process performed at the reporting unit level. We have determined the reporting units for our goodwill impairment test are our operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which our chief operating decision makers regularly review the operating results. For more information on our operating segments, see note 2 to consolidated financial statements. The first step of the quantitative impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit’s goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. At December 31, 2017, the fair value substantially exceeded the carrying value at all our reporting units reported under continuing operations.

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Conducting a qualitative assessment to determine if the fair value of a reporting unit is more likely than not in excess of its carrying value and determining the fair value of a reporting unit under quantitative testing requires judgment and the use of significant estimates which include assumptions about the reporting unit's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. We use a discounted cash flow methodology for our income approach. Under this approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital at each reporting unit. Under the market approach, we estimate fair value using multiples derived from comparable enterprise value to EBITDA multiples, comparable price earnings ratios, comparable enterprise value to sales multiples and if available, comparable sales transactions for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. When performing a qualitative assessment, we evaluate whether forecast scenarios used in the most recent quantitative fair value calculation continue to be reasonable considering industry events and the reporting unit's current circumstances. We believe the estimates and assumptions used in our impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not impairment is indicated.

FORWARD-LOOKING INFORMATION – SAFE HARBOR STATEMENT UNDER THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 (the Act). When used in this Form 10-K and in future filings by the Company with the SEC, in the Company's press releases and in oral statements, words such as "may," "will," "expect," "anticipate," "continue," "estimate," "project," "believes" or similar expressions are intended to identify forward-looking statements within the meaning of the Act. Such statements are based on current expectations and assumptions, and entail various risks and uncertainties that could cause actual results to differ materially from those expressed in such forward-looking statements. Such risks and uncertainties include the various factors set forth in Item 1A. Risk Factors of this Annual Report on Form 10-K and in our other SEC filings.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

At December 31, 2017 we had exposure to market risk associated with interest rates because OTP had $112.4 million in short-term debt outstanding subject to variable interest rates indexed to LIBOR plus 1.25% under the OTP Credit Agreement.

All of our remaining consolidated long-term debt outstanding on December 31, 2017 has fixed interest rates. We manage our interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt.

We have not used interest rate swaps to manage net exposure to interest rate changes related to our portfolio of borrowings. We maintain a ratio of fixed-rate debt to total debt within a certain range. It is our policy to enter into interest rate transactions and other financial instruments only to the extent considered necessary to meet our stated objectives. We do not enter into interest rate transactions for speculative or trading purposes.

The companies in our Manufacturing segment are exposed to market risk related to changes in commodity prices for steel, aluminum and polystyrene and other plastics resins. The price and availability of these raw materials could affect the revenues and earnings of our Manufacturing segment.

The plastics companies are exposed to market risk related to changes in commodity prices for PVC resins, the raw material used to manufacture PVC pipe. The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices are rising or stable, sales volume has been higher and when resin prices are falling, sales volume has been lower. Operating income may decline when the supply of PVC pipe increases faster than demand. Due to the commodity nature of PVC resin and the dynamic supply and demand factors worldwide, it is very difficult to predict gross margin percentages or to assume that historical trends will continue.

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of
Otter Tail Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets and statements of capitalization of Otter Tail Corporation and subsidiaries (the "Company") as of December 31, 2017 and 2016, and the related consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Otter Tail Corporation and subsidiaries as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

Basis for Opinions

The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report Regarding Internal Controls Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Minneapolis, Minnesota

February 20, 2018

We have served as the Company's auditor since 1944.

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S&P Global Market Intelligence

OTTER TAIL CORPORATION
Consolidated Balance Sheets, December 31

(in thousands)		**2017**		2016
ASSETS				
Current Assets				
Cash and Cash Equivalents	**$**	**16,216**	$	--
Accounts Receivable:				
Trade (less allowance for doubtful accounts of $1,094 for 2017 and $1,246 for 2016)		**68,466**		68,242
Other		**7,761**		5,850
Inventories		**88,034**		83,740
Unbilled Revenues		**22,427**		20,080
Income Taxes Receivable		**1,181**		662
Regulatory Assets		**22,551**		21,297
Other		**12,491**		8,144
Total Current Assets		**239,127**		208,015
Investments		**8,629**		8,417
Other Assets		**36,006**		34,104
Goodwill		**37,572**		37,572
Other Intangibles–Net		**13,765**		14,958
Regulatory Assets		**129,576**		132,094
Plant				
Electric Plant in Service		**1,981,018**		1,860,357
Nonelectric Operations		**216,937**		211,826
Construction Work in Progress		**141,067**		153,261
Total Gross Plant		**2,339,022**		2,225,444
Less Accumulated Depreciation and Amortization		**799,419**		748,219
Net Plant		**1,539,603**		1,477,225
Total Assets	**$**	**2,004,278**	$	1,912,385

See accompanying notes to consolidated financial statements.

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OTTER TAIL CORPORATION

Consolidated Balance Sheets, December 31

(in thousands, except share data)	**2017**	2016
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	**$ 112,371**	$ 42,883
Current Maturities of Long-Term Debt	**186**	33,201
Accounts Payable	**84,185**	89,350
Accrued Salaries and Wages	**21,534**	17,497
Accrued Taxes	**16,808**	16,000
Regulatory Liabilities	**9,688**	3,294
Other Accrued Liabilities	**11,389**	12,083
Liabilities of Discontinued Operations	**492**	1,363
Total Current Liabilities	**256,653**	215,671
Pensions Benefit Liability	**109,708**	97,627
Other Postretirement Benefits Liability	**69,774**	62,571
Other Noncurrent Liabilities	**22,769**	21,706
Commitments and Contingencies (note 8)		
Deferred Credits		
Deferred Income Taxes	**100,501**	226,591
Deferred Tax Credits	**21,379**	22,849
Regulatory Liabilities	**232,893**	82,433
Other	**3,329**	7,492
Total Deferred Credits	**358,102**	339,365
Capitalization (page 67)		
Long-Term Debt—Net	**490,380**	505,341
Cumulative Preferred Shares – Authorized 1,500,000 Shares Without Par Value; Outstanding – None	--	--
Cumulative Preference Shares – Authorized 1,000,000 Shares Without Par Value; Outstanding – None	--	--
Common Shares, Par Value $5 Per Share–Authorized, 50,000,000 Shares; Outstanding, 2017—39,557,491 Shares; 2016—39,348,136 Shares	**197,787**	196,741
Premium on Common Shares	**343,450**	337,684
Retained Earnings	**161,286**	139,479
Accumulated Other Comprehensive Loss	**(5,631)**	(3,800)
Total Common Equity	**696,892**	670,104
Total Capitalization	**1,187,272**	1,175,445
Total Liabilities and Equity	**$ 2,004,278**	$ 1,912,385

See accompanying notes to consolidated financial statements.

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OTTER TAIL CORPORATION

Consolidated Statements of Income–For the Years Ended December 31

(in thousands, except per-share amounts)	**2017**	2016	2015
Operating Revenues			
Electric	**$ 434,506**	$ 427,349	$ 407,039
Product Sales	**414,844**	376,190	372,765
Total Operating Revenues	**849,350**	803,539	779,804
Operating Expenses			
Production Fuel – Electric	**59,690**	54,792	42,744
Purchased Power – Electric System Use	**64,807**	63,226	78,150
Electric Operation and Maintenance Expenses	**151,319**	151,225	140,768
Cost of Products Sold (depreciation included below)	**316,562**	295,222	295,032
Other Nonelectric Expenses	**43,240**	40,264	40,021
Depreciation and Amortization	**72,545**	73,445	60,363
Property Taxes – Electric	**15,053**	14,266	13,512
Total Operating Expenses	**723,216**	692,440	670,590
Operating Income	**126,134**	111,099	109,214
Interest Charges	**29,604**	31,886	31,160
Other Income	**2,632**	2,905	2,177
Income Before Income Taxes – Continuing Operations	**99,162**	82,118	80,231

S&P Global Market Intelligence

Income Tax Expense – Continuing Operations	**27,043**	20,081	21,642
Net Income from Continuing Operations	**72,119**	62,037	58,589
Discontinued Operations			
Income (Loss) – net of Income Tax Expense (Benefit) of $213 in 2017, $138 in 2016, and ($1,539) in 2015	**320**	284	(5,404)
Impairment Loss – net of Income Tax (Benefit) of $0 in 2015	**--**	--	(1,000)
Gain on Disposition – net of Income Tax Expense of $4,530 in 2015	**--**	--	7,160
Net Income from Discontinued Operations	**320**	284	756
Total Net Income	**$ 72,439**	$ 62,321	$ 59,345
Average Number of Common Shares Outstanding–Basic	**39,457**	38,546	37,495
Average Number of Common Shares Outstanding–Diluted	**39,748**	38,731	37,668
Basic Earnings Per Common Share:			
Continuing Operations	**$ 1.83**	$ 1.61	$ 1.56
Discontinued Operations	**$ 0.01**	$ 0.01	$ 0.02
	$ 1.84	$ 1.62	$ 1.58
Diluted Earnings Per Common Share:			
Continuing Operations	**$ 1.81**	$ 1.60	$ 1.56
Discontinued Operations	**$ 0.01**	$ 0.01	$ 0.02
	$ 1.82	$ 1.61	$ 1.58
Dividends Declared Per Common Share	**$ 1.28**	$ 1.25	$ 1.23

See accompanying notes to consolidated financial statements.

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OTTER TAIL CORPORATION
Consolidated Statements of Comprehensive Income–For the Years Ended December 31

(in thousands)	**2017**	2016	2015
Net Income	**$ 72,439**	$ 62,321	$ 59,345
Other Comprehensive Income (Loss):			
Unrealized Loss on Available-for-Sale Securities:			
Reversal of Previously Recognized Gains Realized on Sale of Investments and Included in Other Income During Period	**(15)**	(3)	(3)
Gains (Losses) Arising During Period	**115**	(14)	(49)
Income Tax (Expense) Benefit	**(35)**	6	18
Change in Unrealized Losses on Available-for-Sale Securities – net-of-tax	**65**	(11)	(34)
Pension and Postretirement Benefit Plans:			
Actuarial (Losses) Gains Net of Regulatory Allocation Adjustment	**(3,791)**	(445)	510
Amortization of Unrecognized Postretirement Benefit Costs (note 10)	**629**	628	821
Income Tax Benefit (Expense)	**1,266**	(74)	(532)
Pension and Postretirement Benefit Plans – net-of-tax	**(1,896)**	109	799
Total Other Comprehensive Income (Loss)	**(1,831)**	98	765
Total Comprehensive Income	**$ 70,608**	$ 62,419	$ 60,110

See accompanying notes to consolidated financial statements.

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OTTER TAIL CORPORATION
Consolidated Statements of Common Shareholders' Equity

(in thousands, except common shares outstanding)	**Common Shares Outstanding**	**Par Value, Common Shares**	**Premium on Common Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Income/(Loss)**	**Total Common Equity**
Balance, December 31, 2014	**37,218,053**	**$ 186,090**	**$ 278,436**	**$ 112,903**	**$ (4,663) (a)**	**$ 572,766**
Common Stock Issuances, Net of Expenses	690,485	3,453	14,715			18,168
Common Stock Retirements	(51,352)	(257)	(1,339)			(1,596)
Net Income				59,345		59,345
Other Comprehensive Income					765	765
Tax Benefit – Stock Compensation			82			82
Employee Stock Incentive Plan Expense			1,716			1,716
Common Dividends ($1.23 per share)				(46,223)		(46,223)
Balance, December 31, 2015	**37,857,186**	**$ 189,286**	**$ 293,610**	**$ 126,025**	**$ (3,898) (a)**	**$ 605,023**
Common Stock Issuances, Net of Expenses	1,494,618	7,473	38,490			45,963
Common Stock Retirements	(3,668)	(18)	(86)			(104)
Net Income				62,321		62,321
Other Comprehensive Income					98	98
Employee Stock Incentive Plan Expense			3,178			3,178

ASU 2016-09 Adoption			2,492	(623)		1,869
Common Dividends ($1.25 per share)				(48,244)		(48,244)
Balance, December 31, 2016	**39,348,136**	**$ 196,741**	**$ 337,684**	**$ 139,479**	**$ (3,800) (a)**	**$ 670,104**
Common Stock Issuances, Net of Expenses	257,059	1,285	3,684			4,969
Common Stock Retirements	(47,704)	(239)	(1,560)			(1,799)
Net Income				72,439		72,439
Other Comprehensive Income					(1,831)	(1,831)
Employee Stock Incentive Plan Expense			3,642			3,642
Common Dividends ($1.28 per share)				(50,632)		(50,632)
Balance, December 31, 2017	**39,557,491**	**$ 197,787**	**$ 343,450**	**$ 161,286**	**$ (5,631) (a)**	**$ 696,892**

(a) Accumulated Other Comprehensive Loss on December 31 is comprised of the following:

(in thousands)	**2017**	2016	2015
Unrealized Gain (Loss) on Marketable Equity Securities:			
Before Tax	**$ 71**	$ (29)	$ (12)
Tax Effect	**(25)**	10	4
Unrealized Gain (Loss) on Marketable Equity Securities – net-of-tax	**46**	(19)	(8)
Unamortized Actuarial Losses and Prior Service Costs Related to Pension and Postretirement Benefits:			
Before Tax	**(9,462)**	(6,300)	(6,484)
Tax Effect	**3,785**	2,519	2,594
Unamortized Actuarial Losses and Prior Service Costs Related to Pension and Postretirement Benefits – net-of-tax	**(5,677)**	(3,781)	(3,890)
Accumulated Other Comprehensive Loss:			
Before Tax	**(9,391)**	(6,329)	(6,496)
Tax Effect	**3,760**	2,529	2,598
Net Accumulated Other Comprehensive Loss	**$ (5,631)**	$ (3,800)	$ (3,898)

See accompanying notes to consolidated financial statements.

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OTTER TAIL CORPORATION
Consolidated Statements of Cash Flows—For the Years Ended December 31

(in thousands)	**2017**	2016	2015
Cash Flows from Operating Activities			
Net Income	**$ 72,439**	$ 62,321	$ 59,345
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Net Gain from Sale of Discontinued Operations	**--**	--	(7,160)
Net (Income) Loss from Discontinued Operations	**(320)**	(284)	6,404
Depreciation and Amortization	**72,545**	73,445	60,363
Deferred Tax Credits	**(1,470)**	(1,657)	(1,878)
Deferred Income Taxes	**24,001**	19,124	26,027
Change in Deferred Debits and Other Assets	**(2,173)**	(10,090)	11,407
Discretionary Contribution to Pension Fund	**--**	(10,000)	(10,000)
Change in Noncurrent Liabilities and Deferred Credits	**19,257**	14,685	20,524
Allowance for Equity/Other Funds Used During Construction	**(986)**	(857)	(1,303)
Change in Derivatives Net of Regulatory Deferral	**--**	--	(14,736)
Stock Compensation Expense – Equity Awards	**3,642**	3,178	1,716
Other—Net	**10**	7	(80)
Cash (Used for) Provided by Current Assets and Current Liabilities:			
Change in Receivables	**(2,135)**	(944)	(1,746)
Change in Inventories	**(4,294)**	1,874	1,960
Change in Other Current Assets	**(3,060)**	(2,541)	(210)
Change in Payables and Other Current Liabilities	**(2,667)**	11,941	(15,150)
Change in Interest Payable and Income Taxes Receivable/Payable	**(1,186)**	3,339	(3,943)
Net Cash Provided by Continuing Operations	**173,603**	163,541	131,540
Net Cash Used in Discontinued Operations	**(26)**	(155)	(14,000)
Net Cash Provided by Operating Activities	**173,577**	163,386	117,540
Cash Flows from Investing Activities			
Capital Expenditures	**(132,913)**	(161,259)	(160,084)
Proceeds from Disposal of Noncurrent Assets	**4,491**	4,837	3,590
Acquisition Purchase Price Cash Received (Paid)	**--**	1,500	(30,806)
Cash Used for Investments and Other Assets	**(4,168)**	(4,402)	(6,302)
Net Cash Used in Investing Activities – Continuing Operations	**(132,590)**	(159,324)	(193,602)
Net Proceeds from Sale of Discontinued Operations	**--**	--	39,401
Net Cash Used in Investing Activities – Discontinued Operations	**--**	--	(1,769)
Net Cash Used in Investing Activities	**(132,590)**	(159,324)	(155,970)
Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	**2,434**	(3,363)	2,857
Net Short-Term Borrowings (Repayments)	**69,488**	(37,789)	69,818
Proceeds from Issuance of Common Stock – net of Issuance Expenses	**4,349**	43,873	13,782
Payments for Retirement of Capital Stock	**(1,799)**	(104)	(1,596)
Proceeds from Issuance of Long-Term Debt	**--**	130,000	--

Short-Term and Long-Term Debt Issuance Expenses	**(380)**	(888)	(312)
Payments for Retirement of Long-Term Debt	**(48,231)**	(87,547)	(212)
Dividends Paid and Other Distributions	**(50,632)**	(48,244)	(46,223)
Net Cash (Used in) Provided by Financing Activities – Continuing Operations	**(24,771)**	(4,062)	38,114
Net Cash Provided by Financing Activities – Discontinued Operations	--	--	316
Net Cash (Used in) Provided by Financing Activities	**(24,771)**	(4,062)	38,430
Net Change in Cash and Cash Equivalents	**16,216**	--	--
Cash and Cash Equivalents at Beginning of Period	**--**	--	--
Cash and Cash Equivalents at End of Period	**$ 16,216**	$ --	$ --

See accompanying notes to consolidated financial statements.

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OTTER TAIL CORPORATION
Consolidated Statements of Capitalization, December 31

(in thousands, except share data)	**2017**	2016
Short-Term Debt		
Otter Tail Corporation Credit Agreement	**$ --**	$ --
Otter Tail Power Company Credit Agreement	**112,371**	42,883
Total Short-Term Debt	**$ 112,371**	$ 42,883
Long-Term Debt		
Obligations of Otter Tail Corporation		
Term Loan, LIBOR plus 0.90%, due February 5, 2018	**$ --**	$ 15,000
3.55% Guaranteed Senior Notes, due December 15, 2026	**80,000**	80,000
North Dakota Development Note, 3.95%, due April 1, 2018	**27**	106
Partnership in Assisting Community Expansion (PACE) Note, 2.54%, due March 18, 2021	**684**	836
Total – Otter Tail Corporation	**80,711**	95,942
Less: Current Maturities--net of Unamortized Debt Issuance Costs	**186**	231
Unamortized Long-Term Debt Issuance Costs	**461**	539
Total Otter Tail Corporation Long-Term Debt net of Unamortized Debt Issuance Costs	**80,064**	95,172
Obligations of Otter Tail Power Company		
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	--	33,000
Senior Unsecured Notes 4.63%, due December 1, 2021	**140,000**	140,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	**30,000**	30,000
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	**42,000**	42,000
Senior Unsecured Notes 4.68%, Series A, due February 27, 2029	**60,000**	60,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	**50,000**	50,000
Senior Unsecured Notes 5.47%, Series B, due February 27, 2044	**90,000**	90,000
Total – Otter Tail Power Company	**412,000**	445,000
Less: Current Maturities--net of Unamortized Debt Issuance Costs	--	32,970
Unamortized Long-Term Debt Issuance Costs	**1,684**	1,861
Total Otter Tail Power Company Long-Term Debt net of Unamortized Debt Issuance Costs	**410,316**	410,169
Total Consolidated Long-Term Debt	**492,711**	540,942
Less: Current Maturities--net of Unamortized Debt Issuance Costs	**186**	33,201
Unamortized Long-Term Debt Issuance Costs	**2,145**	2,400
Total Consolidated Long-Term Debt net of Unamortized Debt Issuance Costs	**490,380**	505,341
Cumulative Preferred Shares—Without Par Value, Authorized 1,500,000 Shares; Outstanding: None		
Cumulative Preference Shares–Without Par Value, Authorized 1,000,000 Shares; Outstanding: None		
Total Common Shareholders' Equity	**696,892**	670,104
Total Capitalization	**$ 1,187,272**	$ 1,175,445

See accompanying notes to consolidated financial statements.

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Otter Tail Corporation
Notes to Consolidated Financial Statements
For the years ended December 31, 2017, 2016 and 2015

1. Summary of Significant Accounting Policies

Principles of Consolidation
The consolidated financial statements of Otter Tail Corporation and its wholly owned subsidiaries (the Company) include the accounts of the following segments: Electric, Manufacturing and Plastics. See note 2 to consolidated financial statements for further descriptions of the Company's business segments. All intercompany balances and transactions have been eliminated in consolidation except profits on sales to the regulated electric utility company from nonregulated affiliates, which is in accordance with the requirements of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 980, *Regulated Operations* (ASC 980).

Regulation and ASC 980

The Company's regulated electric utility company, Otter Tail Power Company (OTP), accounts for the financial effects of regulation in accordance with ASC 980. This standard allows for the recording of a regulatory asset or liability for costs and revenues that will be collected or refunded through the ratemaking process in the future. In accordance with regulatory treatment, OTP defers utility debt redemption premiums and amortizes such costs over the original life of the reacquired bonds. See note 4 to consolidated financial statements for further discussion.

OTP is subject to various state and federal agency regulations. The accounting policies followed by this business are subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the Company's nonelectric businesses.

Plant, Retirements and Depreciation

Utility plant is stated at original cost. The cost of additions includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction. The amount of interest capitalized on electric utility plant was $741,000 in 2017, $495,000 in 2016 and $723,000 in 2015. The cost of depreciable units of property retired less salvage is charged to accumulated depreciation. Removal costs, when incurred, are charged against the accumulated reserve for estimated removal costs, a regulatory liability. Maintenance, repairs and replacement of minor items of property are charged to operating expenses. The provisions for utility depreciation for financial reporting purposes are made on the straight-line method based on the estimated remaining service lives of the properties (5 to 82 years). Such provisions as a percent of the average balance of depreciable electric utility property were 2.74% in 2017, 2.88% in 2016 and 2.61% in 2015. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Property and equipment of nonelectric operations are carried at historical cost or at fair value if acquired in a business combination, and are depreciated on a straight-line basis over the assets' estimated useful lives (3 to 40 years). The cost of additions includes contracted work, direct labor and materials, allocable overheads and capitalized interest. No interest was capitalized on nonelectric plant in 2017, 2016 or 2015. Maintenance and repairs are expensed as incurred. Gains or losses on asset dispositions are included in the determination of operating income.

Recoverability of Long-Lived Assets

The Company reviews its long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. The Company determines potential impairment by comparing the carrying amount of the assets with net cash flows expected to be provided by operating activities of the business or related assets. If the sum of the expected future net cash flows is less than the carrying amount of the assets, the Company would recognize an impairment loss. Such an impairment loss would be measured as the amount by which the carrying amount exceeds the fair value of the asset, where fair value is based on the discounted cash flows expected to be generated by the asset.

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Jointly Owned Facilities

OTP is a joint owner in two coal-fired steam-powered electric generation plants: Big Stone Plant near Big Stone City, South Dakota and Coyote Station near Beulah, North Dakota. OTP is also a joint owner, with other regional utilities, in four major in-service transmission lines and one additional major transmission line under construction. The following table provides OTP's ownership percentages and amounts included in the Company's December 31, 2017 and 2016 consolidated balance sheets for OTP's share of jointly owned assets in each of these jointly owned facilities:

Jointly Owned Facilities *(dollars in thousands)*	OTP Ownership Percentage	Electric Plant in Service	Construction Work in Progress	Accumulated Depreciation	Net Plant
December 31, 2017					
Big Stone Plant	53.9%	$ 329,942	$ 1,074	$ (74,165)	$ 256,851
Coyote Station	35.0%	177,721	158	(103,944)	73,935
Fargo-Monticello 345 kV line	14.2%	78,192	--	(4,667)	73,525
Brookings-Southeast Twin Cities 345 kV line[1]	4.8%	26,269	--	(1,293)	24,976
Bemidji-Grand Rapids 230 kV line	14.8%	16,331	--	(1,753)	14,578
Big Stone South–Brookings 345 kV line[1]	50.0%	53,225	--	(434)	52,791
Big Stone South–Ellendale 345 kV line[1]	50.0%	--	89,980	--	89,980
December 31, 2016					
Big Stone Plant	53.9%	$ 328,809	$ 23	$ (65,665)	$ 263,167
Coyote Station	35.0%	176,315	113	(101,499)	74,929
Fargo-Monticello 345 kV line	14.2%	78,298	--	(3,511)	74,787
Brookings-Southeast Twin Cities 345 kV line[1]	4.8%	26,406	--	(924)	25,482
Bemidji-Grand Rapids 230 kV line	14.8%	16,331	--	(1,573)	14,758
Big Stone South–Brookings 345 kV line[1]	50.0%	--	45,050	--	45,050
Big Stone South–Ellendale 345 kV line[1]	50.0%	--	49,160	--	49,160

[1]*Midcontinent Independent System Operator, Inc. (MISO) Multi-Value Project (MVP) designation provides for a return on invested funds while under construction under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff).*

The Company's share of direct revenue and expenses of the jointly owned facilities is included in operating revenue and expenses in the consolidated statements of income.

Coyote Station Lignite Supply Agreement – Variable Interest Entity—In October 2012 the Coyote Station owners, including OTP, entered into a lignite sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (CCMC), a subsidiary of The North American Coal Corporation, for the purchase of lignite coal to meet the coal supply requirements of Coyote Station for the period beginning in May 2016 and ending in December 2040. The price per ton paid by the Coyote Station owners under the LSA reflects the cost of production, along with an agreed profit and capital charge. CCMC was formed for the purpose of mining coal to meet the coal fuel supply requirements of Coyote Station from May 2016 through December 2040 and, based on the terms of the LSA, is considered a variable interest entity (VIE) due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so that the price of the coal would cover all costs of operations as well as future reclamation costs. The Coyote Station owners are also providing a guarantee of the value of the assets of CCMC as they would be required to buy certain assets at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of CCMC in that they are required to buy the entity at the end of the contract term at equity value. Under current accounting standards, the primary beneficiary of a VIE is required to include the assets, liabilities, results of operations and cash flows of the VIE in its consolidated financial statements. No single owner of Coyote Station owns a majority interest in Coyote Station and none, individually, has the power to direct the activities that most significantly impact CCMC. Therefore, none of the owners individually, including OTP, is considered a primary beneficiary of the VIE and the Company is not required to include CCMC in its consolidated financial statements.

If the LSA terminates prior to the expiration of its term or the production period terminates prior to December 31, 2040 and the Coyote Station owners purchase all of the outstanding membership interests of CCMC as required by the LSA, the owners will satisfy, or (if permitted by CCMC's applicable lender) assume, all of CCMC's obligations

owed to CCMC's lenders under its loans and leases. The Coyote Station owners have limited rights to assign their rights and obligations under the LSA without the consent of CCMC's lenders during any period in which CCMC's obligations to its lenders remain outstanding. In the event the contract is terminated because regulations or legislation render the burning of coal cost prohibitive and the assets worthless, OTP's maximum exposure to loss as a result of its involvement with CCMC as of December 31, 2017 could be as high as $57.1 million, OTP's 35% share of unrecovered costs.

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Income Taxes

Comprehensive interperiod income tax allocation is used for substantially all book and tax temporary differences. Deferred income taxes arise for all temporary differences between the book and tax basis of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect in the periods when the temporary differences reverse. The Company amortizes investment tax credits over the estimated lives of related property. The Company records income taxes in accordance with ASC Topic 740, *Income Taxes*, and has recognized in its consolidated financial statements the tax effects of all tax positions that are "more-likely-than-not" to be sustained on audit based solely on the technical merits of those positions as of the balance sheet date. The term "more-likely-than-not" means a likelihood of more than 50%. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes. See note 13 to consolidated financial statements regarding the Company's accounting for uncertain tax positions.

The Company also is required to assess the realizability of its deferred tax assets, taking into consideration the Company's forecast of future taxable income, the reversal of other existing temporary differences, available net operating loss carryforwards and available tax planning strategies that could be implemented to realize the deferred tax assets. Based on this assessment, management must evaluate the need for, and amount of, valuation allowances against the Company's deferred tax assets. To the extent facts and circumstances change in the future, adjustments to the valuation allowance may be required.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (TCJA) was signed into law. The major impacts of the changes included in the TCJA are discussed in note 13 to consolidated financial statements.

Revenue Recognition

Due to the diverse business operations of the Company, revenue recognition depends on the product produced and sold or service performed. The Company recognizes revenue when the earnings process is complete, evidenced by an agreement with the customer, there has been delivery and acceptance, the price is fixed or determinable and collectability is reasonably assured. In cases where significant obligations remain after delivery, revenue recognition is deferred until such obligations are fulfilled. Provisions for sales returns are recorded at the time of the sale based on historical information and current trends.

For the Company's operating companies recognizing revenue on certain products when shipped, those operating companies have no further obligation to provide services related to such product. The shipping terms used in these instances are FOB shipping point. The majority of the revenues recorded by the companies in the Manufacturing and Plastics segments are recorded when products are shipped.

Customer electricity use is metered and bills are rendered monthly. Revenue is accrued for electricity consumed but not yet billed. Rate schedules applicable to substantially all customers include a fuel clause adjustment, under which the rates are adjusted to reflect changes in average cost of fuels and purchased power, and a surcharge for recovery of conservation-related expenses. Revenue is recognized for fuel and purchased power costs incurred in excess of amounts recovered in base rates but not yet billed through the fuel clause adjustment, for conservation program incentives and bonuses earned but not yet billed and for renewable resource, transmission-related and environmental incurred costs and investment returns approved for recovery through riders.

Revenues on wholesale electricity sales from Company-owned generating units are recognized when energy is delivered. For shared use of transmission facilities with certain regional transmission cooperatives, revenues are estimated. Bills are rendered based on anticipated usage and settlements are made later based on actual usage. Estimated revenues may be adjusted prior to settlement, or at the time of settlement, to reflect actual usage.

Under ASC Topic 815, *Derivatives and Hedging*, OTP accounts for forward energy contracts as derivatives subject to mark-to-market accounting unless those contracts meet the definition of a capacity contract or are not subject to unplanned netting, then OTP accounts for the contracts under the normal purchases and sales exception to mark-to-market accounting.

Warranty Reserves

Certain products sold by the Company's manufacturing and plastics companies carry product warranties for one year after the shipment date. These companies' standard product warranty terms generally include post-sales support and repairs or replacement of a product at no additional charge for a specified period of time. While these companies engage in extensive product quality programs and processes, including actively monitoring and evaluating the quality of their component suppliers, they base their estimated warranty obligations on warranty terms, ongoing product failure rates, repair costs, product call rates, average cost per call, and current period product shipments. The Company's manufacturing and plastics companies have not incurred any significant warranty costs over the last three fiscal years.

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Shipping and Handling Costs

The Company includes revenues received for shipping and handling in operating revenues. Expenses paid for shipping and handling are recorded as part of cost of goods sold.

Use of Estimates

The Company uses estimates based on the best information available in recording transactions and balances resulting from business operations. As better information becomes available (or actual amounts are known), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash Equivalents

The Company considers all highly liquid debt instruments purchased with maturity of 90 days or less to be cash equivalents.

Investments

The following table provides a breakdown of the Company's investments at December 31:

(in thousands)	2017	2016
Cost Method:		
Economic Development Loan Pools	$ 45	$ 54

Other		115		115
Equity Method Partnerships		24		23
Marketable Debt Securities Classified as Available-for-Sale		7,160		8,225
Marketable Equity Securities Classified as Available-for-Sale		1,285		--
Total Investments	$	8,629	$	8,417

The Company's marketable securities classified as available-for-sale are held for insurance purposes and are reflected at their fair values on December 31, 2017. See further discussion below.

Agreements Subject to Legally Enforceable Netting Arrangements

OTP has certain derivative contracts that are designated as normal purchases and carried at historical cost in the accompanying balance sheet. Individual counterparty exposures for these contracts can be offset according to legally enforceable netting arrangements. The Company does not offset assets and liabilities under legally enforceable netting arrangements on the face of its consolidated balance sheet.

Fair Value Measurements

The Company follows ASC Topic 820, *Fair Value Measurements and Disclosures* (ASC 820), for recurring fair value measurements. ASC 820 provides a single definition of fair value, requires enhanced disclosures about assets and liabilities measured at fair value and establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the hierarchy and examples of each level are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange .

Level 2 – Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

Level 3 – Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation and may include complex and subjective models and forecasts.

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The following tables present, for each of the hierarchy levels, the Company's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2017 and December 31, 2016:

December 31, 2017 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Investments:			
Equity Funds – Held by Captive Insurance Company	$ 1,285		
Corporate Debt Securities – Held by Captive Insurance Company		$ 5,373	
Government-Backed and Government-Sponsored Enterprises' Debt Securities – Held by Captive Insurance Company		1,787	
Other Assets:			
Money Market and Mutual Funds – Nonqualified Retirement Savings Plan	823		
Total Assets	$ 2,108	$ 7,160	

December 31, 2016 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Investments:			
Corporate Debt Securities – Held by Captive Insurance Company		$ 5,280	
Government-Backed and Government-Sponsored Enterprises' Debt Securities – Held by Captive Insurance Company		2,945	
Other Assets:			
Money Market and Mutual Funds – Nonqualified Retirement Savings Plan	$ 849		
Total Assets	$ 849	$ 8,225	

The valuation techniques and inputs used for the Level 2 fair value measurements in the table above are as follows:

Government-Backed and Government-Sponsored Enterprises' and Corporate Debt Securities Held by the Company's Captive Insurance Company – Fair values are determined on the basis of valuations provided by a third-party pricing service which utilizes industry accepted valuation models and observable market inputs to determine valuation. Some valuations or model inputs used by the pricing service may be based on broker quotes.

Inventories

Electric segment inventories are reported at average cost. The Manufacturing and Plastics segments' inventories are stated at the lower of average cost or market. Inventories consist of the following at December 31:

(in thousands)	2017	2016
Finished Goods	$ 26,605	$ 27,755
Work in Process	14,222	11,754
Raw Material, Fuel and Supplies	47,207	44,231
Total Inventories	$ 88,034	$ 83,740

Goodwill and Other Intangible Assets

The Company accounts for goodwill and other intangible assets in accordance with the requirements of ASC Topic 350, *Intangibles—Goodwill and Other*, measuring its goodwill for impairment annually in the fourth quarter, and more often when events indicate the assets may be impaired. The Company does qualitative assessments of its reporting units with recorded goodwill to determine if it is more likely than not that the fair value of the reporting unit exceeds its book value. The Company also does

quantitative assessments of its reporting units with recorded goodwill to determine the fair value of the reporting unit.

In the first quarter of 2015, Foley recorded a $1.0 million goodwill impairment charge based on adjustments to the carrying value of Foley. The first quarter 2015 goodwill impairment loss is reflected in the results of discontinued operations. See note 15 to consolidated financial statements.

On September 1, 2015 BTD Manufacturing, Inc. (BTD), acquired the assets of Impulse Manufacturing, Inc. (Impulse) of Dawsonville, Georgia. The acquired business operates under the name BTD-Georgia. Based on the preliminary purchase price allocation, the difference in the fair value of assets acquired and the price paid for Impulse resulted in an initial estimate of acquired goodwill of $8.2 million. A final determination of the purchase price was agreed to in June 2016 resulting in a $2.2 million reduction in acquired goodwill in June 2016.

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The following tables summarize changes to goodwill by business segment during 2017 and 2016:

(in thousands)	Gross Balance December 31, 2016	Accumulated Impairments	Balance (net of impairments) December 31, 2016	Adjustments to Goodwill in 2017	Balance (net of impairments) December 31, 2017
Manufacturing	$ 18,270	$ --	$ 18,270	$ --	$ 18,270
Plastics	19,302	--	19,302	--	19,302
Total	$ 37,572	$ --	$ 37,572	$ --	$ 37,572

(in thousands)	Gross Balance December 31, 2015	Accumulated Impairments	Balance (net of impairments) December 31, 2015	Adjustments to Goodwill in 2016	Balance (net of impairments) December 31, 2016
Manufacturing	$ 20,430	$ --	$ 20,430	$ (2,160)	$ 18,270
Plastics	19,302	--	19,302	--	19,302
Total	$ 39,732	$ --	$ 39,732	$ (2,160)	$ 37,572

Intangible assets with finite lives are amortized over their estimated useful lives and reviewed for impairment in accordance with requirements under ASC Topic 360-10-35, *Property, Plant, and Equipment—Overall—Subsequent Measurement*. In 2017 the Company capitalized $154,000 in implementation costs for new financial reporting consolidation software included in other amortizable intangible assets. In September 2017 the Company initiated use of the software and began amortizing the implementation costs.

The following table summarizes the components of the Company's intangible assets at December 31, 2017 and December 31, 2016:

December 31, 2017 *(in thousands)*	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Remaining Amortization Periods (months)
Amortizable Intangible Assets:				
Customer Relationships	$ 22,491	$ 8,994	$ 13,497	24 - 212
Covenant not to Compete	590	459	131	8
Other	154	17	137	32
Total	$ 23,235	$ 9,470	$ 13,765	
December 31, 2016 *(in thousands)*				
Amortizable Intangible Assets:				
Customer Relationships	$ 22,491	$ 7,861	$ 14,630	36 - 224
Covenant not to Compete	590	262	328	20
Total	$ 23,081	$ 8,123	$ 14,958	

The amortization expense for these intangible assets was:

(in thousands)	2017	2016	2015
Amortization Expense – Intangible Assets	$ 1,347	$ 1,436	$ 1,127

The estimated annual amortization expense for these intangible assets for the next five years is:

(in thousands)	2018	2019	2020	2021	2022
Estimated Amortization Expense – Intangible Assets	$ 1,315	$ 1,184	$ 1,133	$ 1,099	$ 1,099

Supplemental Disclosures of Cash Flow Information

(in thousands)	As of December 31, 2017	2016
Noncash Investing Activities:		
Transactions Related to Capital Additions not Settled in Cash	$ 13,887	$ 13,533

(in thousands)	2017	2016	2015
Cash Paid (Received) During the Year for:			
Interest (net of amount capitalized)	$ 29,791	$ 31,269	$ 30,512
Income Taxes	$ 5,064	$ (1,291)	$ 7,322

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New Accounting Standards Adopted

Accounting Standards Update (ASU) 2015-11—In July 2015 the Financial Accounting Standards Board (FASB) issued ASU No. 2015-11, *Inventory (Topic* 330*): Simplifying the Measurement of Inventory*, which requires that inventories be measured at the lower of cost or net realizable value instead of the lower of cost or market value. Net realizable value is defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The standards update was effective prospectively for fiscal years and interim periods beginning after December 15, 2016. The Company adopted the updates in ASU 2015-11 in the first quarter of 2017. The adoption of the updated standard did not have a material impact on the Company's consolidated financial statements as market and net realizable value were substantially the same for the inventories of its manufacturing companies.

New Accounting Standards Pending Adoption

ASU 2014-09—In May 2014 the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers (Topic* 606*)* (ASC 606). ASC 606 is a comprehensive, principles-based accounting standard which amends current revenue recognition guidance with the objective of improving revenue recognition requirements by providing a single comprehensive model to determine the measurement of revenue and the timing of revenue recognition. ASC 606 also requires expanded disclosures to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

Amendments to the ASC in ASU 2014-09, as amended, are effective for fiscal years beginning after December 15, 2017. Early adoption is permitted. Application methods permitted are: (1) full retrospective, (2) retrospective using one or more practical expedients and (3) retrospective with the cumulative effect of initial application recognized at the date of initial application. As of December 31, 2017 the Company had reviewed its revenue streams and contracts and determined areas where the amendments in ASU 2014-09 are applicable and has developed controls for new processes that will be required to track and report revenues where the timing of revenue recognition may change under ASU 2014-09. Based on review of the Company's revenue streams, the Company has not identified any contracts where the timing of revenue recognition will change as a result of the adoption of the updates in ASU 2016-09. The Company will adopt the updates in ASU 2014-09 on a modified retrospective basis on January 1, 2018, the date of initial application, but will not be recording a cumulative effect adjustment to retained earnings on application of the updates because the adoption of the updates in ASU 606 have no material impact on the timing of revenue recognition for the Company or its subsidiaries. Adoption of ASU 2014-09 will result in additional disclosures related to the nature, timing and certainty of revenues and any contract assets or liabilities that may be required to be reported under the updated standard.

The Company will report adjustments to Alternative Revenue Program (ARP) revenues at OTP as a separate line item within revenue on the face of the Company's consolidated statements of income. The ARP revenue adjustments are recorded on the basis of recoverable costs incurred and returns earned under rate riders and are not considered revenue from contracts with customers.

ASU 2016-02—In February 2016 the FASB issued ASU No. 2016-02, *Leases (Topic* 842*)* (ASU 2016-02). ASU 2016-02 is a comprehensive amendment of the ASC, creating Topic 842, which will supersede the current requirements under ASC Topic 840 on leases and require the recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. Topic 842 affects any entity that enters into a lease, with some specified scope exemptions. The main difference between previous Generally Accepted Accounting Principles in the United States (GAAP) and Topic 842 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. Topic 842 retains a distinction between finance leases and operating leases. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous guidance. Topic 842 also requires qualitative and specific quantitative disclosures by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. The amendments in ASU 2016-02 are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application of the amendments in ASU 2016-02 is permitted. The Company has developed a list of all current leases outstanding and continues to review ASU 2016-02, identifying key impacts to its businesses to determine areas where the amendments in ASU 2016-02 will be applicable and is evaluating transition options. The Company does not currently plan to apply the amendments in ASU 2016-02 to its consolidated financial statements prior to 2019.

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ASU 2017-04—In January 2017 the FASB issued ASU No. 2017-04, *Intangibles—Goodwill and Other (Topic* 350*): Simplifying the Test for Goodwill Impairment* (ASU 2017-04), which simplifies how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit's goodwill with the carrying amount of that goodwill. In computing the implied fair value of goodwill under Step 2, an entity has to perform procedures to determine the fair value at the impairment testing date of its assets and liabilities (including unrecognized assets and liabilities) following the procedure that would be required in determining the fair value of assets acquired and liabilities assumed in a business combination. Under the amendments in ASU 2017-04, an entity will perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity will recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized will not exceed the total amount of goodwill allocated to that reporting unit. Additionally, an entity will consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable.

The amendments in ASU 2017-04 modify the concept of impairment from the condition that exists when the carrying amount of goodwill exceeds its implied fair value to the condition that exists when the carrying amount of a reporting unit exceeds its fair value. An entity no longer will determine goodwill impairment by calculating the implied fair value of goodwill by assigning the fair value of a reporting unit to all of its assets and liabilities as if that reporting unit had been acquired in a business combination. Because these amendments eliminate Step 2 from the goodwill impairment test, they should reduce the cost and complexity of evaluating goodwill for impairment. The amendments in ASU 2017-04 are effective for annual or any interim goodwill impairment tests in fiscal years beginning after December 15, 2019. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017.

ASU 2017-07—In March 2017 the FASB issued ASU No. 2017-07, *Compensation—Retirement Benefits (Topic* 715*): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07), which is intended to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost. ASC Topic 715, *Compensation—Retirement Benefits* (ASC 715), does not prescribe where the amount of net benefit cost should be presented in an employer's income statement and does not require entities to disclose by line item the amount of net benefit cost that is included in the income statement or capitalized in assets. The amendments in ASU 2017-07 require that an employer report the service cost component of periodic benefit costs in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit cost as defined in ASC 715 are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The amendments in ASU 2017-07 also allow only the service cost component to be eligible for capitalization when applicable (for example, as a cost of internally manufactured inventory or a self-constructed asset). The amendments in ASU 2017-07 are effective for annual periods beginning after December 15, 2017, including interim periods within those annual periods. The amendments will be applied retrospectively for the presentation of the service cost component and the other components of net periodic pension cost and net periodic postretirement benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension cost and net periodic postretirement benefit cost in assets.

The majority of the Company's benefit costs to which the amendments in ASU 2017-07 apply are related to benefit plans in place at OTP, the Company's regulated provider of electric utility services. The amendments in ASU 2017-07 deviate significantly from current prescribed ratemaking and regulatory accounting treatment of postretirement benefit costs, which require the capitalization of a portion of all the components of net periodic benefit costs be included in rate base additions and provide for rate recovery

of the non-capitalized portion of all of the components of net periodic pension costs as recoverable operating expenses. The Company has assessed the impact adoption of the amendments in ASU 2017-07 will have on its consolidated financial statements, financial position and results of operations and OTP has determined the regulatory assets to be established in order to reflect the effect of the required regulatory accounting treatment of the non-service cost components that cannot be capitalized to plant in service under the ASU 2017-07 amendments to GAAP. The non-service cost components of the affected net periodic benefit costs will be reported below the operating income line on the Company's consolidated income statements upon adoption of the amendments in ASU 2017-07.

The Company does not plan to adopt the updates in ASU 2017-07 prior to the first quarter of 2018, the required effective period for application of the updates by the Company. The Company's non-service cost components of net periodic post-retirement benefit costs that were capitalized to plant in service in 2017 that would have been recorded as regulatory assets if the amendments in ASU 2017-07 were applicable in 2017 were $0.8 million. The Company's non-service costs components of net periodic postretirement benefit costs included in operating expense that will be included in other income and deductions on adoption of ASU 2017-07 were $5.6 million in 2017 and $5.1 million in 2016.

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2. Business Combinations, Dispositions and Segment Information

Business Combinations
The Company acquired no new businesses in 2017 or 2016.

On September 1, 2015 BTD acquired the assets of Impulse of Dawsonville, Georgia for $30.8 million in cash. A post-closing reduction in the purchase price of $1.5 million was agreed to in June 2016 resulting in an adjusted purchase price of $29.3 million. The acquired business, operating under the name BTD-Georgia, is a full-service metal fabricator located 30 miles north of Atlanta, Georgia, which offers a wide range of metal fabrication services ranging from simple laser cutting services and high volume stamping to complex weldments and assemblies for metal fabrication buyers and original equipment manufacturers. In addition to serving some of BTD's existing customers from a location closer to the customers' manufacturing facilities, this acquisition provides opportunities for growth in new and existing markets for BTD with complementing production capabilities that expand the capacity of services offered by BTD. Pro forma results of operations have not been presented for this acquisition because the effect of the acquisition was not material to the Company.

Below is condensed balance sheet information disclosing the final allocation of the purchase price assigned to each major asset and liability category of BTD-Georgia:

(in thousands)		
Assets:		
Current Assets	$	4,906
Goodwill		6,083
Other Intangible Assets		6,270
Other Amortizable Assets		1,380
Fixed Assets		13,649
Total Assets	$	32,288
Liabilities:		
Current Liabilities	$	2,971
Lease Obligation		11
Total Liabilities	$	2,982
Cash Paid	$	29,306

In execution of the Company's announced strategy of realigning its business portfolio to reduce its risk profile and dedicate a greater portion of its resources toward electric utility operations, the Company sold several of its holdings in recent years. On December 31, 2014 the Company was in the process of negotiating the sales of Foley, its mechanical and prime contractor on industrial projects, and AEV, Inc., its electrical design and construction services company, which resulted in the removal of its Construction segment from continuing operations. The sale of Foley closed on April 30, 2015 and the sale of the assets of AEV, Inc. closed on February 28, 2015.

The results of operations of the Company's recently disposed businesses are reported as discontinued operations in the Company's consolidated financial statements as of and for the years ended December 31, 2017, 2016 and 2015, and are summarized in note 15 to consolidated financial statements.

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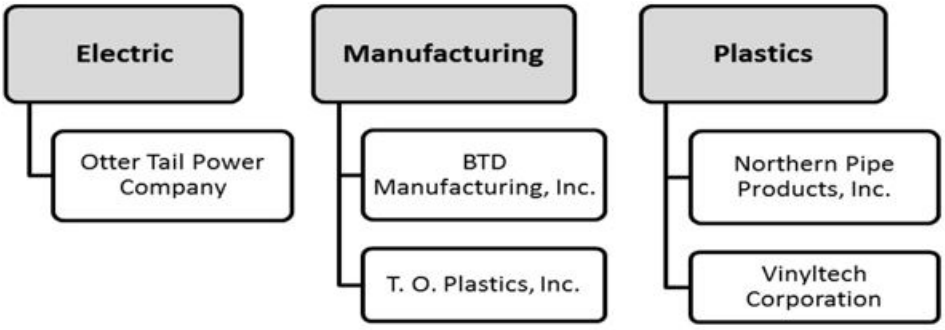
Segment Information
The accounting policies of the segments are described under note 1 – Summary of Significant Accounting Policies. The Company's businesses have been classified into three segments to be consistent with its business strategy and the reporting and review process used by the Company's chief operating decision makers. These businesses sell products and provide services to customers primarily in the United States. The Company's business structure currently includes the following three segments: Electric, Manufacturing and Plastics. The chart below indicates the companies included in each segment.



Electric includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota by OTP. In addition, OTP is a participant in the MISO markets. OTP's operations have been the Company's primary business since 1907.

Manufacturing consists of businesses in the following manufacturing activities: contract machining, metal parts stamping, fabrication and painting, and production of plastic thermoformed horticultural containers, life science and industrial packaging, and material handling components. These businesses have manufacturing facilities in Georgia, Illinois and Minnesota and sell products primarily in the United States.

Plastics consists of businesses producing polyvinyl chloride (PVC) pipe at plants in North Dakota and Arizona. The PVC pipe is sold primarily in the upper Midwest and Southwest regions of the United States.

OTP is a wholly owned subsidiary of the Company. All of the Company's other businesses are owned by its wholly owned subsidiary, Varistar Corporation (Varistar). The Company's Corporate operating costs include items such as corporate staff and overhead costs, the results of the Company's captive insurance company and other items excluded from the measurement of operating segment performance. Corporate assets consist primarily of cash, prepaid expenses, investments and fixed assets. Corporate is not an operating segment. Rather, it is added to operating segment totals to reconcile to totals on the Company's consolidated financial statements.

No single customer accounted for over 10% of the Company's consolidated revenues in 2017, 2016 and 2015. While no single customer accounted for over 10% of consolidated revenue in 2017, certain customers provided a significant portion of each business segment's 2017 revenue. The Electric segment has one customer that provided 11.7% of 2017 Electric segment revenues. The Manufacturing segment has one customer that manufactures and sells recreational vehicles that provided 24.3% of 2017 Manufacturing segment revenues and one customer that manufactures and sells lawn and garden equipment that provided 12.0% of 2017 Manufacturing segment revenues. The Plastics segment has two customers that individually provided 20.6% and 17.8% of 2017 Plastics segment revenues. The loss of any one of these customers would have a significant negative impact on the financial position and results of operations of the respective business segment and the Company.

All of the Company's long-lived assets are within the United States and sales within the United States accounted for 98.2% of sales in 2017, 98.6% of sales in 2016 and 97.1% of sales in 2015.

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The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information on continuing operations for the business segments for 2017, 2016 and 2015 is presented in the following table:

(in thousands)	2017	2016	2015
Operating Revenue			
Electric	$ 434,537	$ 427,383	$ 407,131
Manufacturing	229,738	221,289	215,011
Plastics	185,132	154,901	157,758
Intersegment Eliminations	(57)	(34)	(96)
Total	$ 849,350	$ 803,539	$ 779,804
Cost of Products Sold			
Manufacturing	$ 176,473	$ 171,732	$ 171,956
Plastics	140,107	123,496	123,085
Intersegment Eliminations	(18)	(6)	(9)
Total	$ 316,562	$ 295,222	$ 295,032
Other Nonelectric Expenses			
Manufacturing	$ 23,785	$ 21,994	$ 21,116
Plastics	11,564	9,402	9,849
Corporate	7,930	8,896	9,143
Intersegment Eliminations	(39)	(28)	(87)
Total	$ 43,240	$ 40,264	$ 40,021
Depreciation and Amortization			
Electric	$ 53,276	$ 53,743	$ 44,786
Manufacturing	15,379	15,794	11,853
Plastics	3,817	3,861	3,552
Corporate	73	47	172
Total	$ 72,545	$ 73,445	$ 60,363
Operating Income (Loss)			
Electric	$ 90,392	$ 90,131	$ 87,171
Manufacturing	14,101	11,769	10,086
Plastics	29,644	18,142	21,272
Corporate	(8,003)	(8,943)	(9,315)
Total	$ 126,134	$ 111,099	$ 109,214
Interest Charges			
Electric	$ 25,334	$ 25,069	$ 24,371
Manufacturing	2,215	3,859	3,560
Plastics	633	1,034	1,026
Corporate and Intersegment Eliminations	1,422	1,924	2,203
Total	$ 29,604	$ 31,886	$ 31,160
Income Tax Expense (Benefit) – Continuing Operations			
Electric	$ 17,013	$ 16,366	$ 16,067
Manufacturing	989	2,276	2,299
Plastics	7,448	6,538	8,187
Corporate	1,593	(5,099)	(4,911)
Total	$ 27,043	$ 20,081	$ 21,642
Net Income (Loss)			
Electric	$ 49,446	$ 49,829	$ 48,370
Manufacturing	11,050	5,694	4,247

S&P Global Market Intelligence

Plastics	21,696	10,628	12,108
Corporate	(10,073)	(4,114)	(6,136)
Discontinued Operations	320	284	756
Total	$ 72,439	$ 62,321	$ 59,345

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(in thousands)	2017	2016	2015
Capital Expenditures			
Electric	$ 118,444	$ 149,648	$ 135,572
Manufacturing	9,916	8,429	20,295
Plastics	4,432	3,085	4,206
Corporate	121	97	11
Total	$ 132,913	$ 161,259	$ 160,084
Identifiable Assets			
Electric	$ 1,690,224	$ 1,622,231	$ 1,520,887
Manufacturing	167,023	166,525	173,860
Plastics	87,230	84,592	81,624
Corporate	59,801	39,037	42,312
Total	$ 2,004,278	$ 1,912,385	$ 1,818,683

3. Rate and Regulatory Matters

Below are descriptions of OTP's major capital expenditure projects that have had, or will have, a significant impact on OTP's revenue requirements, rates and alternative revenue recovery mechanisms, followed by summaries of specific electric rate or rider proceedings with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the FERC, impacting OTP's revenues in 2017, 2016 and 2015.

Major Capital Expenditure Projects

Big Stone South–Ellendale Multi-Value Transmission Project (MVP)—This is a 345-kiloVolt (kV) transmission line that will extend 163 miles between a substation near Big Stone City, South Dakota and a substation near Ellendale, North Dakota. OTP jointly developed this project with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., and the parties will have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff) in December 2011. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple areas within the MISO region. The cost allocation is designed to ensure the costs of transmission projects with regional benefits are properly assigned to those who benefit. Construction began on this line in the second quarter of 2016 and is expected to be completed in 2019. OTP's capitalized costs on this project as of December 31, 2017 were approximately $90.0 million, which includes assets that are 100% owned by OTP.

Big Stone South–Brookings MVP—This 345-kV transmission line extends approximately 70 miles between a substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Northern States Power–Minnesota, a subsidiary of Xcel Energy Inc., jointly developed this project and the parties have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Tariff in December 2011. Construction began on this line in the third quarter of 2015 and the line was energized on September 8, 2017. OTP's capitalized costs on this project as of December 31, 2017 were approximately $72.7 million, which includes assets that are 100% owned by OTP.

Recovery of OTP's major transmission investments is through the MISO Tariff (several as MVPs) and, currently, Minnesota, North Dakota and South Dakota Transmission Cost Recovery (TCR) Riders.

Reagent Costs

OTP's systemwide costs for reagents are expected to increase to approximately $2.2 million annually through May 2021 when Hoot Lake Plant is expected to be retired. The Minnesota, North Dakota and South Dakota share of costs are approximately 50%, 40% and 10%, respectively. Reagent costs for the Big Stone Plant AQCS and Coyote Station and Hoot Lake Plant Mercury and Air Toxics Standards (MATS) were initially incurred in 2015 when projects went into service.

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Minnesota

2016 General Rate Case—The MPUC rendered its final decision in OTP's 2016 general rate case in March 2017 and issued its written order on May 1, 2017. Pursuant to the order, OTP's allowed rate of return on rate base decreased from 8.61% to 7.5056% and its allowed rate of return on equity decreased from 10.74% to 9.41%. On July 6, 2017 the MPUC denied OTP's request for reconsideration of certain of the MPUC's rulings in the rate case and confirmed its May 1, 2017 order.

The MPUC's order also included: (1) the determination that all costs (including FERC allocated costs and revenues) of the Big Stone South–Brookings and Big Stone South–Ellendale MVP projects will be included in the Minnesota TCR rider and jurisdictionally allocated to OTP's Minnesota customers, and (2) approval of OTP's proposal to transition rate base, expenses and revenues from Environmental Cost Recovery (ECR) and TCR riders to base rate recovery, with the transition occurring when final rates are implemented. The rate base balances, expense levels and revenue levels existing in the riders at the time of implementation of final rates will be used to establish the amounts transitioned to base rates. Certain MISO expenses and revenues will remain in the TCR rider to allow for the ongoing refund or recovery of these variable revenues and costs.

Information on interim and final rate increases and interim revenue refunds accrued is detailed in the tables below:

($ in thousands)	Interim Rates Authorized April 14, 2016	Final Rates
Revenue Increase – Annualized based on Test Year Data	$ 16,816	$ 10,471

Revenue Percent Increase	9.56%	5.34%
Return on Rate Base	8.07%	7.5056%
Jurisdictional Rate Base based on Test Year Data	$ 483,000	$ 471,000
Return on Equity	10.40%	9.41%
Based on Equity to Total Capital of	52.50%	52.50%
Debt to Total Capital	47.50%	47.50%

Interim Revenue *(in thousands)*	April 16, 2016 through October 31, 2017
Billed	$ 23,289
Accrued Refund	$ 8,779
Net Interim Revenue	$ 14,510
Interest on Refundable Amount	$ 265
Final Refund	$ 9,044

In addition to the interim rate refund, OTP will be required to refund the difference between (1) amounts collected under its Minnesota ECR and TCR riders based on the return on equity (ROE) approved in its most recent rider update and (2) amounts that would have been collected based on the lower 9.41% ROE approved in its 2016 general rate case going back to April 16, 2016, the date interim rates were implemented. As of October 31, 2017 the revenues collected under the Minnesota ECR and TCR riders subject to refund due to the lower ROE rate and other adjustments were $0.9 million and $1.4 million, respectively. These amounts will be refunded to Minnesota customers over a 12-month period through reductions in the Minnesota ECR and TCR rider rates in effect November 1, 2017, as approved by the MPUC. The TCR rate is provisional and subject to revision under a separate docket.

OTP accrued interim and rider rate refunds until final rates became effective, for bills rendered on and after November 1, 2017. The final interim rate refund, including interest, of $9.0 million was applied as a credit to Minnesota customers' electric bills beginning November 17, 2017.

Minnesota Conservation Improvement Programs (MNCIP)—Under Minnesota law, every regulated public utility that furnishes electric service must make annual investments and expenditures in energy conservation improvements, or make a contribution to the state's energy and conservation account, in an amount equal to at least 1.5% of its gross operating revenues from service provided in Minnesota.

The Minnesota Department of Commerce (MNDOC) may require a utility to make investments and expenditures in energy conservation improvements whenever it finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of a new supply of energy. Such MNDOC orders can be appealed to the MPUC. Investments made pursuant to such orders generally are recoverable costs in rate cases, even though ownership of the improvement may belong to the property owner rather than the utility. OTP recovers conservation related costs not included in base rates under the MNCIP through the use of an annual recovery mechanism approved by the MPUC.

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On May 25, 2016 the MPUC adopted the MNDOC's proposed changes to the MNCIP financial incentive. The new model provides utilities an incentive of 13.5% of 2017 net benefits, 12% of 2018 net benefits and 10% of 2019 net benefits, assuming the utility achieves 1.7% savings compared to retail sales. OTP estimates the impact of the new model will reduce the MNCIP financial incentive by approximately 50% compared to the previous incentive mechanism. MNCIP incentives included $5.0 million approved for 2016 and $4.3 million approved for 2015.

Based on results from the 2017 MNCIP program year, OTP recognized a financial incentive of $2.6 million in 2017. The 2017 program resulted in an approximate 10% decrease in energy savings compared to 2016 program results. OTP will request approval for recovery of its 2017 MNCIP program costs not included in base rates, a $2.6 million financial incentive and an update to the MNCIP surcharge from the MPUC by April 1, 2018.

Transmission Cost Recovery Rider—The Minnesota Public Utilities Act (the MPU Act) provides a mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that have been previously approved by the MPUC in a Certificate of Need (CON) proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or exempt from the requirement to obtain a Minnesota CON. The MPUC may also authorize cost recovery via such TCR riders for charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the MISO to benefit the utility or integrated transmission system. The MPU Act also authorizes TCR riders to recover the costs of new transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that state, and determined by the MISO to benefit the utility or integrated transmission system. Finally, under certain circumstances, the MPU Act also authorizes TCR riders to recover the costs associated with distribution planning and investments in distribution facilities to modernize the utility grid. Such TCR riders allow a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule. MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from other MISO customers.

In OTP's 2016 general rate case order issued on May 1, 2017, the MPUC ordered OTP to include, in the TCR rider retail rate base, Minnesota's jurisdictional share of OTP's investment in the Big Stone South–Brookings and Big Stone South–Ellendale MVP Projects and all revenues received from other utilities under MISO's tariffed rates as a credit in its TCR revenue requirement calculations. In doing so, the MPUC's order diverts interstate wholesale revenues that have been approved by the FERC to offset FERC-approved expenses, effectively reducing OTP's recovery of those FERC-approved expense levels. The MPUC-ordered treatment will result in the projects being treated as retail investments for Minnesota retail ratemaking purposes. Because the FERC's revenue requirements and authorized returns will vary from the MPUC revenue requirements and authorized returns for the project investments over the lives of the projects, the impact of this decision will vary over time and be dependent on the differences between the revenue requirements and returns in the two jurisdictions at any given time. On August 18, 2017 OTP filed an appeal of the MPUC order with the Minnesota Court of Appeals to contest the portion of the order requiring OTP to allocate costs between jurisdictions of the FERC MVP transmission projects in the TCR rider. OTP believes the MPUC-ordered treatment conflicts with federal authority over transmission of electricity in interstate commerce and rates for the transmission of electricity subject to the jurisdiction of the FERC as set forth in the Federal Power Act of 1935, as amended (Federal Power Act). A decision is expected in late 2018.

Environmental Cost Recovery Rider— OTP had an ECR rider for recovery of OTP's Minnesota jurisdictional share of the revenue requirements of its investment in the Big Stone Plant Air Quality Control System (AQCS). The ECR rider provided for a return on the project's construction work in progress (CWIP) balance at the level approved in OTP's 2010 general rate case. In its 2016 general rate case order, the MPUC approved OTP's proposal to transition eligible rate base and expense recovery from the ECR rider to base rate recovery, effective with implementation of final rates in November 2017.

Reagent Costs and Emission Allowances—On July 31, 2014 OTP filed a request with the MPUC to revise its Fuel Clause Adjustment (FCA) rider in Minnesota to include recovery of reagent and emission allowance costs. On March 12, 2015 the MPUC denied OTP's request to revise its FCA rider to include recovery of these costs. These costs were included in OTP's 2016 general rate case in Minnesota and were considered for recovery either through the FCA rider or general rates. In its 2016 general rate case order

issued May 1, 2017 the MPUC again denied OTP's request for recovery of test-year reagent costs and emission allowances in base fuel costs or through the FCA rider. Instead, the test-year costs will be recovered in general rates and variability of those costs in excess of amounts included in general rates will only be recovered to the extent actual kilowatt-hour (kwh) sales exceed forecasted kwh sales used to establish general rates.

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North Dakota

General Rates—On November 2, 2017 OTP filed a request with the NDPSC for a rate review and an effective increase in annual revenues from non-fuel base rates of $13.1 million or 8.72%. In the request, OTP proposed an allowed return on rate base of 7.97% and an allowed rate of return on equity of 10.30%. On December 20, 2017 the NDPSC approved OTP's request for interim rates to increase annual revenue collections by $12.8 million, effective January 1, 2018. OTP used a lower rate of return on equity in the calculation of interim rates based on the rate of return on equity used in its 2018 test-year rate request.

OTP's most recent general rate increase in North Dakota of $3.6 million, or approximately 3.0%, was granted by the NDPSC in an order issued on November 25, 2009 and effective December 2009. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.62%, and its allowed rate of return on equity was set at 10.75%.

Renewable Resource Adjustment—OTP has a North Dakota Renewable Resource Adjustment which enables OTP to recover its North Dakota jurisdictional share of investments in renewable energy facilities. This rider allows OTP to recover costs associated with new renewable energy projects as they are completed, along with a return on investment.

Transmission Cost Recovery Rider—North Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. For qualifying projects, the law authorizes a current return on CWIP and a return on investment at the level approved in the utility's most recent general rate case.

Environmental Cost Recovery Rider—OTP has an ECR rider in North Dakota to recover its North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects. The ECR rider provides for a return on investment at the level approved in OTP's most recent general rate case and for recovery of OTP's North Dakota share of reagent and emission allowance costs.

South Dakota

2010 General Rate Case—OTP's most recent general rate increase in South Dakota of approximately $643,000 or approximately 2.32% was granted by the SDPUC in an order issued on April 21, 2011 and effective with bills rendered on and after June 1, 2011. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.50%.

Transmission Cost Recovery Rider—South Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities.

Environmental Cost Recovery Rider—OTP has an ECR rider in South Dakota to recover its South Dakota jurisdictional share of revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects.

Reagent Costs and Emission Allowances—On August 1, 2014 OTP filed a request with the SDPUC to revise its FCA rider in South Dakota to include recovery of reagent and emission allowance costs. On September 16, 2014 the SDPUC approved OTP's request to include recovery of these costs in its South Dakota FCA rider.

TCJA

The TCJA reduced the federal corporate income tax rate from 35% to 21%. Currently, all OTP rates have been developed using a 35% tax rate. The MPUC, the NDPSC, the SDPUC and the FERC have all initiated dockets or proceedings to begin working with utilities to assess the impact of the lower income tax rates under the TCJA on electric rates, and develop regulatory strategies to incorporate the tax change into future rates, if warranted. The MPUC required its regulated utilities to make filings by January 30, 2018 and February 15, 2018, but has not made a determination on rate treatment. OTP currently has an active rate case in North Dakota and anticipates incorporating the impact of the tax changes to North Dakota rates within that proceeding. The SDPUC required initial comments by February 1, 2018 and indicated that revenues collected subsequent to December 31, 2017 would be subject to refund, pending determination of the impacts of the TCJA. OTP is still assessing these impacts and will continue to work with the respective commissions to determine if any rate adjustments are necessary, and if so, to determine the appropriate timing and approach for making those adjustments.

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Rate Rider Updates

The following table provides summary information on the status of updates since January 1, 2014 for the rate riders described above:

Rate Rider	R - Request Date A - Approval Date	Effective Date Requested or Approved		Annual Revenue *($000s)*	Rate
Minnesota					
Conservation Improvement Program					
2016 Incentive and Cost Recovery	A – September 15, 2017	October 1, 2017	$	9,868	$0.00536/kwh
2015 Incentive and Cost Recovery	A – July 19, 2016	October 1, 2016	$	8,590	$0.00275/kwh
2014 Incentive and Cost Recovery	A – July 10, 2015	October 1, 2015	$	8,689	$0.00287/kwh
2013 Incentive and Cost Recovery	A – September 26, 2014	October 1, 2014	$	8,862	$0.00263/kwh
Transmission Cost Recovery					
2017 Rate Reset[1]	A – October 30, 2017	November 1, 2017	$	(3,311)	Various
2016 Annual Update	A – July 5, 2016	September 1, 2016	$	4,736	Various
2015 Annual Update	A – March 9, 2016	April 1, 2016	$	7,203	Various
2014 Annual Update	A – February 18, 2015	March 1, 2015	$	8,388	Various
2013 Annual Update	A – June 24, 2014	March 1, 2014	$	2,066	Various
Environmental Cost Recovery					

2017 Rate Reset	A – October 30, 2017	November 1, 2017	$	(1,943)	-0.935% of base
2016 Annual Update	A – July 5, 2016	September 1, 2016	$	11,884	6.927% of base
2015 Annual Update	A – March 9, 2016	October 1, 2015	$	12,104	7.006% of base
2014 Annual Update	A – November 26, 2014	December 1, 2014	*$*	*9,229* [2]	7.006% of base
North Dakota					
Renewable Resource Adjustment					
2017 Rate Reset	A – December 20, 2017	January 1, 2018	$	9,989	7.756% of base
2016 Annual Update	A – March 15, 2017	April 1, 2017	$	9,156	7.005% of base
2015 Annual Update	A – June 22, 2016	July 1, 2016	$	9,262	7.573% of base
2014 Annual Update	A – March 25, 2015	April 1, 2015	$	5,441	4.069% of base
2013 Annual Update	A – March 12, 2014	April 1, 2014	$	8,068	$0.00437/kwh
Transmission Cost Recovery					
2017 Annual Update	A – November 29, 2017	January 1, 2018	$	7,959	Various
2016 Annual Update	A – December 14, 2016	January 1, 2017	$	6,916	Various
2015 Annual Update	A – December 16, 2015	January 1, 2016	$	9,985	Various
2014 Annual Update	A – December 17, 2014	January 1, 2015	$	8,463	Various
Environmental Cost Recovery					
2017 Rate Reset	A – December 20, 2017	January 1, 2018	$	8,537	6.629% of base
2017 Annual Update	A – July 12, 2017	August 1, 2017	$	9,917	7.633% of base
2016 Annual Update	A – June 22, 2016	July 1, 2016	$	10,359	7.904% of base
2015 Annual Update	A – June 17, 2015	July 1, 2015	$	12,249	9.193% of base
2014 Annual Update	A – July 10, 2014	August 1, 2014	$	9,880	7.531% of base
South Dakota					
Transmission Cost Recovery					
2017 Annual Update	R – November 1, 2017	March 1, 2018	$	1,779	Various
2016 Annual Update	A – February 17, 2017	March 1, 2017	$	2,053	Various
2015 Annual Update	A – February 12, 2016	March 1, 2016	$	1,895	Various
2014 Annual Update	A – February 13, 2015	March 1, 2015	$	1,538	Various
2013 Annual Update	A – February 18, 2014	March 1, 2014	$	1,349	Various
Environmental Cost Recovery					
2017 Annual Update	A – October 13, 2017	November 1, 2017	$	2,082	$0.00483/kwh
2016 Annual Update	A – October 26, 2016	November 1, 2016	$	2,238	$0.00536/kwh
2015 Annual Update	A – October 15, 2015	November 1, 2015	$	2,728	$0.00643/kwh
2014 Initial Request	A – November 25, 2014	December 1, 2014	$	1,995	$0.00487/kwh

[1]*Approved on a provisional basis in the Minnesota general rate case docket and subject to revision in a separate docket.*

[2]*Amount approved for recovery over ten months through September 30, 2015. Initial 2014 annual update requirement was $10.2 million to be effective October 1, 2014. Due to delayed approval, the amount was reduced for revenues billed under the rider rate in effect from October 1, 2014 through November 30, 2014.*

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Revenues Recorded under Rate Riders

The following table presents revenue recorded by OTP under rate riders in place in Minnesota, North Dakota and South Dakota for the years ended December 31:

Rate Rider *(in thousands)*	2017	2016	2015
Minnesota			
Conservation Improvement Program Costs and Incentives[1]	$ 9,225	$ 12,920	$ 10,724
Transmission Cost Recovery	2,973	5,795	5,202
Environmental Cost Recovery	8,148	12,443	10,238
North Dakota			
Renewable Resource Adjustment	7,620	7,800	8,409
Transmission Cost Recovery	8,729	7,694	6,609
Environmental Cost Recovery	9,782	11,089	9,502
South Dakota			
Transmission Cost Recovery	1,843	1,820	1,290
Environmental Cost Recovery	2,345	2,538	1,967
Conservation Improvement Program Costs and Incentives	598	468	583

[1]*Includes MNCIP costs recovered in base rates.*

FERC

Wholesale power sales and transmission rates are subject to the jurisdiction of the FERC under the Federal Power Act. The FERC is an independent agency with jurisdiction over rates for wholesale electricity sales, transmission and sale of electric energy in interstate commerce, interconnection of facilities, and accounting policies and practices. Filed rates are effective after a one day suspension period, subject to ultimate approval by the FERC.

Multi-Value Transmission Projects—On December 16, 2010 the FERC approved the cost allocation for a new classification of projects in the MISO region called MVPs. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple transmission zones within the MISO region. The cost allocation is designed to ensure that the costs of transmission projects with regional benefits are properly assigned to those who benefit.

On November 12, 2013 a group of industrial customers and other stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff. The complainants sought to reduce the 12.38% ROE used in MISO's transmission rates to a proposed 9.15%. The complaint established a 15-month refund period from November 12, 2013 to February 11, 2015. A non-binding decision by the presiding Administrative Law Judge (ALJ) was issued on December 22, 2015 finding that the MISO transmission owners' ROE should be 10.32%, and the FERC issued an order on September 28, 2016 setting the base ROE at 10.32%. A number of parties requested rehearing of the September 2016 order and the requests are pending FERC action.

On November 6, 2014 a group of MISO transmission owners, including OTP, filed for a FERC incentive of an additional 50-basis points for Regional Transmission Organization participation (RTO Adder). On January 5, 2015 the FERC granted the request, deferring collection of the RTO Adder until the FERC issued its order in the ROE complaint proceeding. Based on the FERC adjustment to the MISO Tariff ROE resulting from the November 12, 2013 complaint and OTP's incentive rate filing, OTP's ROE will be 10.82% (a 10.32% base ROE plus the 0.5% RTO Adder) effective September 28, 2016.

On February 12, 2015 another group of stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff from 12.38% to a proposed 8.67%. This second complaint established a second 15-month refund period from February 12, 2015 to May 11, 2016. The FERC issued an order on June 18, 2015 setting the complaint for hearings before an ALJ, which were held the week of February 16, 2016. A non-binding decision by the presiding ALJ was issued on June 30, 2016 finding that the MISO transmission owners' ROE should be 9.7%. OTP is currently waiting for the issuance of a FERC order on the second complaint.

Based on the probable reduction by the FERC in the ROE component of the MISO Tariff, OTP had a $2.7 million liability on its balance sheet as of December 31, 2016, representing OTP's best estimate of the refund obligations that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on a reduced ROE. MISO processed the refund for the FERC-ordered reduction in the MISO Tariff allowed ROE for the first 15-month refund period in its February and June 2017 billings. The refund, in combination with a decision in the 2016 Minnesota general rate case that affected the Minnesota TCR rider, has resulted in a reduction in OTP's accrued MISO Tariff ROE refund liability from $2.7 million on December 31, 2016 to $1.6 million as of December 31, 2017.

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In June 2014, the FERC adopted a two-step ROE methodology for electric utilities in an order issued in a complaint proceeding involving New England Transmission Owners (NETOs). The issue of how to apply the FERC ROE methodology has been contested in various complaint proceedings, including the two ROE complaints involving MISO transmission owners discussed above. In April 2017 the Court of Appeals for the District of Columbia (D.C. Circuit) vacated and remanded the FERC's June 2014 ROE order in the NETOs' complaint. The D.C. Circuit found that the FERC had not properly determined that the ROE authorized for NETOs prior to June 2014 was unjust and unreasonable. The D.C. Circuit also found that the FERC failed to justify the new ROE methodology. OTP will await the FERC response to the April 2017 action of the D.C. Circuit before determining if an adjustment to its accrued refund liability is required. On September 29, 2017 the MISO transmission owners filed a motion to dismiss the second complaint based on the D.C. Circuit decision in the NETO complaint. If FERC were to act on a motion to dismiss, it would eliminate the refund obligation from the second complaint and the ROE from the first complaint would remain in effect.

4. Regulatory Assets and Liabilities

As a regulated entity, OTP accounts for the financial effects of regulation in accordance with ASC 980. This accounting standard allows for the recording of a regulatory asset or liability for costs that will be collected or refunded in the future as required under regulation. Additionally, ASC 980-605-25 provides for the recognition of revenues authorized for recovery outside of a general rate case under alternative revenue programs which provide for recovery of costs and incentives or returns on investment in such items as transmission infrastructure, renewable energy resources or conservation initiatives. The following tables indicate the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheets:

	December 31, 2017			Remaining Recovery/ Refund Period
(in thousands)	Current	Long-Term	Total	(months)
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$ 9,090	$ 112,487	$ 121,577	see below
Conservation Improvement Program Costs and Incentives[2]	7,385	2,774	10,159	21
Accumulated ARO Accretion/Depreciation Adjustment[1]	--	6,651	6,651	asset lives
Deferred Marked-to-Market Losses[1]	4,063	2,405	6,468	36
Big Stone II Unrecovered Project Costs – Minnesota[1]	650	1,636	2,286	40
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[2]	--	1,985	1,985	24
Debt Reacquisition Premiums[1]	254	960	1,214	177
Big Stone II Unrecovered Project Costs – South Dakota[2]	100	442	542	65
North Dakota Renewable Resource Rider Accrued Revenues[2]	206	236	442	15
North Dakota Deferred Rate Case Expenses Subject to Recovery[1]	309	--	309	12
Minnesota Deferred Rate Case Expenses Subject to Recovery[1]	267	--	267	4
North Dakota Environmental Cost Recovery Rider Accrued Revenues[2]	152	--	152	12
Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues[2]	75	--	75	12
Total Regulatory Assets	$ 22,551	$ 129,576	$ 152,127	
Regulatory Liabilities:				
Deferred Income Taxes	$ --	$ 149,052	$ 149,052	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	--	83,100	83,100	asset lives
Refundable Fuel Clause Adjustment Revenues	5,778	--	5,778	12
Minnesota Environmental Cost Recovery Rider Accrued Refund	1,667	--	1,667	11
Minnesota Transmission Cost Recovery Rider Accrued Refund	802	609	1,411	22
Minnesota Renewable Resource Recovery Rider Accrued Refund	409	--	409	12
North Dakota Transmission Cost Recovery Rider Accrued Refund	349	--	349	12
Revenue for Rate Case Expenses Subject to Refund – Minnesota	208	--	208	4
South Dakota Environmental Cost Recovery Rider Accrued Refund	187	--	187	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	132	48	180	24
South Dakota Transmission Cost Recovery Rider Accrued Refund	151	--	151	12
Other	5	84	89	192
Total Regulatory Liabilities	$ 9,688	$ 232,893	$ 242,581	
Net Regulatory Asset/(Liability) Position	$ 12,863	$ (103,317)	$ (90,454)	

[1] *Costs subject to recovery without a rate of return.*

[2] *Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.*

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(in thousands)	December 31, 2016 Current	Long-Term	Total	Remaining Recovery/ Refund Period (months)
Regulatory Assets:				
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits[1]	$ 6,443	$ 108,267	$ 114,710	see below
Conservation Improvement Program Costs and Incentives[2]	4,836	5,158	9,994	21
Accumulated ARO Accretion/Depreciation Adjustment[1]	--	6,153	6,153	asset lives
Deferred Marked-to-Market Losses[1]	4,063	6,467	10,530	48
Big Stone II Unrecovered Project Costs – Minnesota[1]	778	2,087	2,865	52
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up[2]	333	--	333	12
Debt Reacquisition Premiums[1]	325	1,214	1,539	189
Big Stone II Unrecovered Project Costs – South Dakota[2]	100	543	643	77
North Dakota Renewable Resource Rider Accrued Revenues[2]	1,319	482	1,801	15
Minnesota Deferred Rate Case Expenses Subject to Recovery[1]	1,082	--	1,082	12
North Dakota Environmental Cost Recovery Rider Accrued Revenues[2]	113	--	113	12
Deferred Income Taxes[1]	--	1,014	1,014	asset lives
Recoverable Fuel and Purchased Power Costs[1]	1,798	--	1,798	12
Minnesota Renewable Resource Rider Accrued Revenues[2]	34	--	34	9
North Dakota Transmission Cost Recovery Rider Accrued Revenues[2]	--	568	568	24
South Dakota Transmission Cost Recovery Rider Accrued Revenues[2]	73	141	214	14
Total Regulatory Assets	$ 21,297	$ 132,094	$ 153,391	
Regulatory Liabilities:				
Deferred Income Taxes	$ --	$ 818	$ 818	asset lives
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	--	80,404	80,404	asset lives
Minnesota Environmental Cost Recovery Rider Accrued Refund	139	--	139	12
Minnesota Transmission Cost Recovery Rider Accrued Refund	757	--	757	12
North Dakota Transmission Cost Recovery Rider Accrued Refund	1,381	782	2,163	24
Revenue for Rate Case Expenses Subject to Refund – Minnesota	711	208	919	16
South Dakota Environmental Cost Recovery Rider Accrued Refund	285	--	285	12
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	--	132	132	24
Other	21	89	110	204
Total Regulatory Liabilities	$ 3,294	$ 82,433	$ 85,727	
Net Regulatory Asset Position	$ 18,003	$ 49,661	$ 67,664	

[1] *Costs subject to recovery without a rate of return.*

[2] *Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.*

The regulatory liability and asset related to Deferred Income Taxes results from changes in statutory tax rates accounted for in accordance with ASC Topic 740, *Income Taxes*.

The regulatory asset related to prior service costs and actuarial losses on pensions and other postretirement benefits represents benefit costs and actuarial losses subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs and actuarial losses are required to be recognized as components of Accumulated Other Comprehensive Income in equity under ASC Topic 715, *Compensation—Retirement Benefits*, but are eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates.

Conservation Improvement Program Costs and Incentives represent mandated conservation expenditures and incentives recoverable through retail electric rates.

The Accumulated Asset Retirement Obligation (ARO) Accretion/Depreciation Adjustment will accrete and be amortized over the lives of property with asset retirement obligations.

All Deferred Marked-to-Market Losses recorded as of December 31, 2017 relate to forward purchases of energy scheduled for delivery through December 2020.

Big Stone II Unrecovered Project Costs – Minnesota are the Minnesota share of generation and transmission plant-related costs incurred by OTP related to its participation in the abandoned Big Stone II project.

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MISO Schedule 26/26A Transmission Cost Recovery Rider True-ups relate to the over/under collection of revenue based on comparison of the expected versus actual construction on eligible projects in the period. The true-ups also include the state jurisdictional portion of MISO Schedule 26/26A for regional transmission cost recovery that was included in the calculation of the state transmission riders and subsequently adjusted to reflect actual billing amounts in the schedule.

Debt Reacquisition Premiums are being recovered from OTP customers over the remaining original lives of the reacquired debt issues, the longest of which is 177 months.

Big Stone II Unrecovered Project Costs – South Dakota are the South Dakota share of generation and transmission plant-related costs incurred by OTP related to its participation in the abandoned Big Stone II project.

North Dakota Renewable Resource Rider Accrued Revenues relate to qualifying renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of December 31, 2017.

North Dakota Deferred Rate Case Expenses Subject to Recovery relate to costs incurred in conjunction with OTP's current rate case in North Dakota currently being recovered over a 12-month period beginning with the establishment of interim rates in January 2018.

Minnesota Deferred Rate Case Expenses Subject to Recovery relate to costs incurred in conjunction with OTP's 2016 rate case in Minnesota currently being recovered over a 24-month period beginning with the establishment of interim rates in April 2016.

North Dakota Environmental Cost Recovery Rider Accrued Revenues relate to revenues earned on the North Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects and for reagent and emission allowances costs that are recoverable from North Dakota customers as of December 31, 2017.

Minnesota Energy Intensive Trade Exposed Rider Accrued Revenues relate to revenues recorded for fuel and purchased power costs reductions provided to customers in energy intensive trade exposed industries that are subject to recovery from other Minnesota customers.

The Accumulated Reserve for Estimated Removal Costs – Net of Salvage is reduced as actual removal costs, net of salvage revenues, are incurred.

The Minnesota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the Minnesota share of OTP's investment in the Big Stone Plant AQCS project that are refundable to Minnesota customers as of December 31, 2017.

The Minnesota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve Minnesota customers that are refundable to Minnesota customers as of December 31, 2017.

The Minnesota Renewable Resource Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve Minnesota customers that are refundable to Minnesota customers as of December 31, 2017.

The North Dakota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve North Dakota customers that are refundable to North Dakota customers as of December 31, 2017.

Revenue for Rate Case Expenses Subject to Refund – Minnesota relates to revenues collected under general rates to recover costs related to prior rate case proceedings in excess of the actual costs incurred, which are subject to refund over a 24-month period beginning with the establishment of interim rates in April 2016.

The South Dakota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the South Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects that are refundable to South Dakota customers as of December 31, 2017.

The South Dakota Transmission Cost Recovery Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities that had not been billed to South Dakota customers as of December 31, 2016.

The South Dakota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve South Dakota customers that are refundable to South Dakota customers as of December 31, 2017.

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If for any reason OTP ceases to meet the criteria for application of guidance under ASC 980 for all or part of its operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from the consolidated balance sheet and included in the consolidated statement of income as an expense or income item in the period in which the application of guidance under ASC 980 ceases.

5. Common Shares and Earnings per Share

Shelf Registration

The Company's shelf registration statement filed with the Securities and Exchange Commission (SEC) on May 11, 2015, under which the Company may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement, including common shares of the Company, expires on May 11, 2018.

Common Share Distribution Agreement

On May 11, 2015, the Company entered into a Distribution Agreement with J.P. Morgan Securities (JPMS) under which it may offer and sell its common shares from time to time in an At-the-Market offering program through JPMS, as its distribution agent, up to an aggregate sales price of $75 million.

Under the Distribution Agreement, the Company will designate the minimum price and maximum number of shares to be sold through JPMS on any given trading day or over a specified period of trading days, and JPMS will use commercially reasonable efforts to sell such shares on such days, subject to certain conditions. Sales of the shares, if any, will be made by means of ordinary brokers' transactions on the NASDAQ Global Select Market at market prices or as otherwise agreed with JPMS. The Company may also agree to sell shares to JPMS, as principal for its own account, on terms agreed by the Company and JPMS in a separate agreement at the time of sale. The Company is not obligated to sell and JPMS is not obligated to buy or sell any of the shares under the Distribution Agreement. The shares, if issued, will be issued pursuant to the Company's existing shelf registration statement.

2017 Common Stock Activity

Following is a reconciliation of the Company's common shares outstanding from December 31, 2016 through December 31, 2017:

Common Shares Outstanding December 31, 2016	39,348,136
Issuances:	
Executive Stock Performance Awards (2014 shares earned)	89,291
Automatic Dividend Reinvestment and Share Purchase Plan:	
Dividends Reinvested	68,235
Cash Invested	29,463
Vesting of Restricted Stock Units	22,225
Restricted Stock Issued to Directors	17,600
Employee Stock Ownership Plan	14,835
Employee Stock Purchase Plan:	

Dividends Reinvested	9,566
Cash Invested	5,284
Directors Deferred Compensation	560
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(47,704)
Common Shares Outstanding December 31, 2017	39,557,491

2014 Stock Incentive Plan

The 2014 Stock Incentive Plan (2014 Incentive Plan), which was approved by the Company's shareholders in April 2014, provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards, and other stock and stock-based awards. A total of 1,900,000 common shares were authorized for granting stock awards under the 2014 Incentive Plan, of which 1,244,353 were available for issuance as of December 31, 2017. The 2014 Incentive Plan terminates on December 13, 2023.

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Employee Stock Purchase Plan

The 1999 Employee Stock Purchase Plan (Purchase Plan) allowed eligible employees to purchase the Company's common shares at 85% of the market price at the end of each six-month purchase period through December 31, 2016. For purchase periods beginning after January 1, 2017, the purchase price is 100% of the market price at the end of each six-month purchase period. On April 16, 2012, the Company's shareholders approved an amendment to the Purchase Plan, increasing the number of shares available under the Purchase Plan from 900,000 common shares to 1,400,000 common shares and making certain other changes to the terms of the Purchase Plan. Of the 1,400,000 common shares authorized to be issued under the Purchase Plan, 374,624 were available for purchase as of December 31, 2017. At the discretion of the Company, shares purchased under the Purchase Plan can be either new issue shares or shares purchased in the open market. To provide shares for purchases for the Purchase Plan, 9,486 common shares were issued in 2017, 53,875 common shares were issued in 2016 and 42,253 common shares were issued in 2015. Shares available for purchase were also reduced by 49 shares in 2017 to reserve for fractional shares.

Dividend Reinvestment and Share Purchase Plan

The Company's shelf registration statement filed with the SEC on May 11, 2015, as amended on October 13, 2015, provides for the issuance of up to 1,500,000 common shares under the Company's Automatic Dividend Reinvestment and Share Purchase Plan (the Plan), which permits shares purchased by participants in the Plan to be either new issue common shares or common shares purchased in the open market. New common shares issued under the Plan totaled 97,698 in 2017, 278,811 in 2016 and 302,519 in 2015, leaving 820,972 common shares available for issuance under the Plan as of December 31, 2017.

Earnings Per Share

The numerator used in the calculation of both basic and diluted earnings per common share is net income with no adjustments in 2017, 2016 and 2015. The denominator used in the calculation of basic earnings per common share is the weighted average number of common shares outstanding during the period excluding nonvested restricted shares granted to the Company's directors and employees, which are considered contingently returnable and not outstanding for the purpose of calculating basic earnings per share. The denominator used in the calculation of diluted earnings per common share is derived by adjusting basic shares outstanding for the items listed in the following reconciliation:

	2017	2016	2015
Weighted Average Common Shares Outstanding – Basic	39,457,261	38,546,459	37,494,986
Plus Outstanding Share Awards net of Share Reductions for Unrecognized Stock-Based Compensation Expense and Excess Tax Benefits:			
Shares Expected to be Awarded for Stock Performance Awards Granted to Executive Officers based on Measurement Period-to-Date Performance	210,784	118,644	100,194
Underlying Shares Related to Nonvested Restricted Stock Units Granted to Employees	56,952	45,712	36,180
Nonvested Restricted Shares	20,380	16,778	22,848
Shares Expected to be Issued Under the Deferred Compensation Program for Directors	2,970	3,417	13,488
Potentially Dilutive Stock Options	--	--	330
Total Dilutive Shares	291,086	184,551	173,040
Weighted Average Common Shares Outstanding – Diluted	39,748,347	38,731,010	37,668,026

The effect of dilutive shares on earnings per share for the years ended December 31, 2017, 2016 and 2015, resulted in no differences greater than $0.014 between basic and diluted earnings per share in total or from continuing or discontinued operations in any period.

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6. Share-Based Payments

Purchase Plan

Through December 31, 2016, the Purchase Plan allowed employees through payroll withholding to purchase shares of the Company's common stock at a 15% discount from the average market price on the last day of a six-month investment period. Under ASC Topic 718, *Compensation—Stock Compensation* (ASC 718), the Company was required to record compensation expense related to the 15% discount. The 15% discount resulted in compensation expense of $173,000 in 2016 and $184,000 in 2015. For purchase periods beginning after January 1, 2017, the purchase price is 100% of the market price at the end of each six-month purchase period.

Stock Options Granted Under the 1999 Incentive Plan

The Company granted 2,041,500 options for the purchase of the Company's common stock under the 1999 Stock Incentive Plan (1999 Incentive Plan). The exercise price of the options granted was the average market price of the Company's common stock on the grant date. Under ASC 718 accounting requirements, compensation expense is recorded based on the estimated fair value of the options on their grant date using a fair-value option pricing model. Under ASC 718 accounting requirements, the fair value of the options granted has been recorded as compensation expense over the requisite service period (the vesting period of the options). The estimated fair value of all options granted under the 1999 Incentive Plan was based on the Black-Scholes option pricing model. There were no options outstanding as of December 31 of each of the years, 2017, 2016 or 2015.

Presented below is a summary of the stock options activity:

Stock Options Activity	2017		2016		2015	
	Options	Average Exercise Price	Options	Average Exercise Price	Options	Average Exercise Price
Outstanding, Beginning of Year	--		--		12,750	$ 24.93
Exercised	--		--		10,250	24.93
Forfeited or Expired	--		--		2,500	24.93
Outstanding, End of Year	--		--		--	
Exercisable, End of Year	--		--		--	
Cash Received for Options Exercised						$ 256,000
Intrinsic Value of Options Exercised						$ 75,000

Restricted Stock Granted to Directors

Under the 1999 Incentive Plan and the 2014 Incentive Plan, restricted shares of the Company's common stock were granted to members of the Company's board of directors as a form of compensation. All remaining restricted shares issued under the 1999 Incentive Plan vested on April 8, 2017. Under ASC 718 accounting requirements, compensation expense related to restricted shares is based on the fair value of the restricted shares on their grant dates. On April 10, 2017, 17,600 shares of restricted stock were granted to the Company's nonemployee directors. The grant-date fair value of each share of restricted stock granted on April 10, 2017 was $37.75 per share, the average of the high and low market price on the date of grant. The restricted shares granted in 2017 vest 25% per year on April 8 of each year in the period 2018 through 2021 and are eligible for full dividend and voting rights. Restricted shares not vested and dividends on those restricted shares are subject to forfeiture under the terms of the restricted stock award agreement.

Presented below is a summary of the status of directors' restricted stock awards for the years ended December 31:

Directors' Restricted Stock Awards	2017		2016		2015	
	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	46,334	$ 29.71	38,217	$ 29.78	38,050	$ 27.47
Granted	17,600	37.75	23,200	28.66	15,200	31.775
Vested	17,134	29.93	15,083	28.28	15,033	25.96
Forfeited	--		--		--	
Nonvested, End of Year	46,800	32.65	46,334	29.71	38,217	29.78
Compensation Expense Recognized		$ 658,000		$ 491,000		$ 417,000
Fair Value of Shares Vested in Year		$ 513,000		$ 427,000		$ 390,000

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Restricted Stock Granted to Employees

Under the 1999 Incentive Plan and 2014 Incentive Plan, restricted shares of the Company's common stock have been granted to employees as a form of compensation. All remaining restricted shares issued under the 1999 Incentive Plan vested on April 8, 2017. Under ASC 718 accounting requirements, compensation expense related to restricted shares is based on the fair value of the restricted shares on their grant dates. No shares of restricted stock have been granted to employees since 2014.

Presented below is a summary of the status of employees' restricted stock awards for the years ended December 31:

Employees' Restricted Stock Awards	2017		2016		2015	
	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	7,180	$ 29.72	13,581	$ 28.56	45,280	$ 27.46
Granted	--		--		--	
Vested	4,285	29.94	6,401	27.25	31,699	27.09
Forfeited	--		--		--	
Nonvested, End of Year	2,895	29.41	7,180	29.72	13,581	28.56
Compensation Expense Recognized		$ 70,000		$ 96,000		$ 359,000
Fair Value of Awards Vested		$ 128,000		$ 174,000		$ 859,000

Restricted Stock Units Granted to Executive Officers

On February 2, 2017, 15,900 restricted stock units under the 2014 Incentive Plan were granted to the Company's executive officers. The grant-date fair value of each restricted stock unit was $37.65 per share, the average of the high and low market price on the date of grant. The restricted stock units granted to executive officers in 2017 vest 25% per year on February 6 of each year in the period 2018 through 2021 and are eligible to receive dividend equivalent payments on all unvested awards over the awards' respective vesting periods, subject to forfeiture under the terms of the restricted stock unit award agreements. The vesting of restricted stock units is accelerated in the event of a change in control, disability, death or retirement, subject to proration on retirement in certain cases.

Presented below is a summary of the status of restricted stock unit awards granted to executive officers for the years ended December 31:

Executives' Restricted Stock Unit Awards	2017		2016		2015	
	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	41,825	$ 30.23	24,300	$ 31.682	--	
Granted	15,900	37.65	22,000	28.915	29,100	$ 31.681
Vested	9,975	30.16	4,475	31.69	4,800	31.675
Forfeited	--		--		--	

Nonvested, End of Year	47,750	32.71	41,825	30.23	24,300	31.682
Compensation Expense Recognized		$ 576,000		$ 446,000		$ 452,000
Fair Value of Awards Vested		$ 301,000		$ 142,000		$ 152,000

Restricted Stock Units Granted to Employees

In 2017 the following restricted stock unit awards under the 2014 Incentive Plan were granted to key employees of the Company who are not executive officers:

	Grant Date	Units Granted	Grant-Date Fair Value per Award
Restricted Stock Units Vesting 100% on April 8, 2021	April 10, 2017	9,995	$ 32.78
Restricted Stock Units Vesting 100% on April 8, 2021	September 25, 2017	1,000	$ 38.29

The grant-date fair value of each restricted stock unit was based on the average of the high and low market price of the Company's common stock on the date of grant, discounted for the value of the dividend exclusion over the four-year vesting period. Under the terms of the restricted stock unit award agreements, all outstanding (unvested) restricted stock units held by a retiring grantee vest immediately on normal retirement.

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Presented below is a summary of the status of employees' restricted stock unit awards for the years ended December 31:

Employees' Restricted Stock Unit Awards	2017		2016		2015	
	Restricted Stock Units	Weighted Average Grant-Date Fair Value	Restricted Stock Units	Weighted Average Grant-Date Fair Value	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	47,370	$ 25.19	46,600	$ 23.75	45,900	$ 21.82
Granted	10,995	33.28	17,220	24.54	15,650	25.89
Vested	11,550	25.30	12,250	19.03	12,250	19.46
Forfeited	375	26.92	4,200	24.51	2,700	22.84
Nonvested, End of Year	46,440	27.07	47,370	25.19	46,600	23.75
Compensation Expense Recognized		$ 331,000		$ 307,000		$ 304,000
Fair Value of Awards Vested		$ 292,000		$ 233,000		$ 238,000

Stock Performance Awards granted to Executive Officers

Agreements for stock performance awards have been granted under the 2014 Incentive Plan for the Company's executive officers. Under these agreements, the officers could be awarded shares of the Company's common stock based on the Company's total shareholder return relative to that of its peer group of companies in the Edison Electric Institute (EEI) Index over a three-year period beginning on January 1 of the year the awards are granted. The awards also include a performance incentive based on the Company's average 3-year adjusted return on equity (ROE) relative to a targeted average 3-year adjusted ROE. The number of shares earned, if any, will be awarded and issued at the end of each three-year performance measurement period. The participants have no voting or dividend rights under these award agreements until common shares, if any, are issued at the end of the performance measurement period.

On February 2, 2017 performance share awards were granted to the Company's executive officers under the 2014 Incentive Plan for the 2017-2019 performance measurement period. Under the 2017 performance share award agreements the aggregate award for performance at target is 59,500 shares. For target performance the participants would earn an aggregate of 39,667 common shares based on the Company's total shareholder return relative to the total shareholder return of the companies that comprise the EEI Index over the performance measurement period of January 1, 2017 through December 31, 2019, with the beginning and ending share values based on the average closing price of a share of the Company's common stock for the 20 trading days immediately following January 1, 2017 and the average closing price for the 20 trading days immediately preceding January 1, 2020. The participants would also earn an aggregate of 19,833 common shares for achieving the target set for the Company's 3-year average adjusted ROE. Actual payment may range from zero to 150% of the target amount, or up to 89,250 common shares. The grant-date fair value of each performance share award was determined using a Monte Carlo fair valuation simulation model resulting in a weighted average fair value of $30.25 per share, except for one grantee whose performance shares were fair valued at $36.27 per share due to retirement provisions in his award agreement.

Under the 2017 performance award agreements payment in the event of retirement, resignation for good reason or involuntary termination without cause is to be made at the end of the performance period based on actual performance, subject to proration in certain cases, except that the payment of performance awards granted to certain officers who are parties to executive employment agreements with the Company is to be made at target at the date of any such event. The vesting of these performance awards is accelerated and paid at target in the event of a change in control, disability or death and on retirement at or after age 62 for certain officers who are parties to executive employment agreements with the Company. The terms of these awards are such that the entire award will be classified and accounted for as equity, as required under ASC 718, and recognized over the grantee's requisite service period based on the grant-date fair value of the award.

The table below provides a summary of stock performance awards granted and amounts expensed related to the stock performance awards:

Performance Period	Maximum Shares Subject To Award	Target Shares	Expense Recognized in the Year Ended December 31, 2017	2016	2015	Earned Shares
2017-2019	89,250	59,500	$ 854,000			7,500
2016-2018	122,250	81,500	580,000	$ 798,000		11,100
2015-2017	126,450	84,300	573,000	535,000	$ 943,000	114,648
2014-2016	159,450	106,300	--	332,000	(64,000)	121,491
2013-2015	90,600	45,300	--	--	(445,000)	22,500
Total			$ 2,007,000	$ 1,665,000	$ 434,000	277,239

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Stock-based payment expense recognized in 2017, 2016 and 2015 for the 2017-2019, 2016-2018 and 2015-2017 performance awards reflects the accelerated recognition of

expense for outstanding and unvested awards of executives who are eligible for retirement and whose awards vest on normal retirement, as defined in the performance award agreements, prior to the vesting dates of the awards.

The earned shares shown in the table above for the 2016-2018 and 2017-2019 performance periods include vested shares to be issued in 2018 to a participant who retired on December 31, 2017 and had reached age 62 prior to retirement.

The earned shares shown in the table above for the 2015-2017 performance period include shares received in 2018 by participants in the plan based on the Company achieving a total shareholder return ranking of 2 out of 42 companies in the EEI Index and an average 3-year adjusted return on equity of 10.16% relative to a targeted average 3-year adjusted return on equity of 10.00% resulting payout at 136.00% of target.

The earned shares shown in the table above for the 2014-2016 performance period include shares received in 2017 by participants in the plan based on the Company achieving a total shareholder return ranking of 19 out of 43 companies in the EEI Index and a resulting payout at 114.29% of target. The earned shares also include shares for a portion of the award that vested on normal retirement of the Company's former CEO on July 1, 2015 that were issued in 2016 following the 180 day deferral period required under the Internal Revenue Code at a value of $26.35 per share or $848,000.

The earned shares shown in the table above for the 2013-2015 performance period reflect shares that vested on normal retirement of the Company's former CEO on July 1, 2015 that were issued in 2016 following the 180 day deferral period required under the Internal Revenue Code at a value of $26.35 per share or $593,000.

In connection with the resignation of an executive officer in May 2014, the following unvested stock performance awards were forfeited: 8,900 granted in 2014 and 4,900 granted in 2013.

As of December 31, 2017 the total remaining unrecognized amount of compensation expense related to stock-based compensation for all of the Company's stock-based payment programs was approximately $4.0 million (before income taxes), which will be amortized over a weighted average period of 2.0 years.

7. Retained Earnings and Dividend Restriction

The Company is a holding company with no significant operations of its own. The primary source of funds for payments of dividends to the Company's shareholders is from dividends paid or distributions made by the Company's subsidiaries. As a result of certain statutory limitations or regulatory or financing agreements, restrictions could occur on the amount of distributions allowed to be made by the Company's subsidiaries.

Both the Company and OTP credit agreements contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be considered to have occurred if the Company did not meet certain financial covenants. As of December 31, 2017 the Company was in compliance with these financial covenants. See note 9 to consolidated financial statements for further information on the covenants.

Under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. What constitutes "funds properly included in a capital account" is undefined in the Federal Power Act or the related regulations; however, the FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials.

The MPUC indirectly limits the amount of dividends OTP can pay to the Company by requiring an equity-to-total-capitalization ratio between 47.4% and 58.0% based on OTP's 2017 capital structure petition approved by order of the MPUC on September 1, 2017. As of December 31, 2017 OTP's equity-to-total-capitalization ratio including short-term debt was 51.4% and its net assets restricted from distribution totaled approximately $471,000,000. Total capitalization for OTP cannot currently exceed $1,178,024,000.

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8. Commitments and Contingencies of Continuing Operations

Construction and Other Purchase Commitments
At December 31, 2017 OTP had commitments under contracts, including its share of construction program commitments, extending into 2019, of approximately $41.0 million. At December 31, 2017 T.O. Plastics had commitments for the purchase of resin through December 31, 2021 of approximately $6.7 million.

Electric Utility Capacity and Energy Requirements and Coal Purchase and Delivery Contracts
OTP has commitments for the purchase of capacity and energy requirements under agreements extending into 2041. OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. OTP's current coal purchase agreements for Big Stone Plant and Coyote Station expire at the end of 2019 and 2040, respectively. OTP has an agreement with Cloud Peak Energy Resources LLC for the purchase of subbituminous coal for Hoot Lake Plant through December 31, 2023. OTP has no fixed minimum purchase requirements under the agreement, but all of Hoot Lake Plant's coal requirements for the period covered must be purchased under this agreement. The dollar amounts of OTP's estimated purchase requirements under this agreement are excluded from the table below because OTP has not committed to any minimum level of purchases under the agreement. Fuel clause adjustment mechanisms lessen the risk of loss from market price changes because they currently provide for recovery of most fuel costs. See table below for schedule of commitments.

Operating Leases
OTP has obligations to make future operating lease payments primarily related to land leases and coal rail-car leases. The Company's nonelectric companies have obligations to make future operating lease payments primarily related to leases of buildings and manufacturing equipment. Rent expense from continuing operations was $7,110,000, $7,565,000 and $6,447,000 for 2017, 2016 and 2015, respectively.

The amounts of the Company's construction program and other commitments and commitments under capacity and energy agreements, coal and coal delivery contracts and operating leases for continuing operations as of December 31, 2017, are as follows:

	Construction Program and Other	Capacity and Energy	Coal Purchase	Operating Leases		
(in thousands)	Commitments	Requirements	Commitments	OTP	Nonelectric	Total
2018	$ 29,218	$ 24,424	$ 26,021	$ 1,838	$ 4,175	$ 6,013
2019	15,159	24,925	23,016	1,435	4,183	5,618

2020	1,680	24,844	22,102	1,436	3,362	4,798
2021	1,680	12,988	22,537	1,241	1,434	2,675
2022	--	11,827	22,300	761	1,439	2,200
Beyond 2022	--	154,310	527,520	8,644	4,326	12,970
Total	$ 47,737	$ 253,318	$ 643,496	$ 15,355	$ 18,919	$ 34,274

Contingencies

OTP had a $2.7 million refund liability on its balance sheet as of December 31, 2016 representing its best estimate of the refund obligations that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on the likelihood of the FERC reducing the ROE component of the MISO Tariff and ordering MISO to refund amounts charged in excess of the lower rate. In the February and June 2017 MISO billings, MISO processed the refund of the FERC-ordered reduction in the MISO Tariff allowed ROE for the first 15-month refund period. The refund, in combination with a decision in the 2016 Minnesota general rate case that affected the Minnesota TCR rider, resulted in a reduction in OTP's accrued MISO Tariff ROE refund liability from $2.7 million as of December 31, 2016 to $1.6 million as of December 31, 2017.

Together with as many as 200 utilities, generators and power marketers, OTP participated in proceedings before the FERC regarding the calculation, assessment and implementation of MISO Revenue Sufficiency Guarantee (RSG) charges for entities participating in the MISO wholesale energy market since that market's start on April 1, 2005 until the conclusion of the proceedings on May 2, 2015. The proceedings fundamentally concerned MISO's application of its MISO RSG rate on file with the FERC to market participants, revisions to the RSG rate based on several FERC orders, and the FERC's decision to not resettle the markets based on MISO application of the RSG rate to market participants. Several of the FERC's orders are on review in a set of consolidated cases before the D.C. Circuit. The consolidated petitions at the D.C. Circuit involve multiple petitioners and intervenors. OTP is an intervenor in these cases. Final briefs were filed on January 26, 2018. Oral arguments will occur in the spring of 2018. A final decision is not expected until late in 2018. MISO has not made available past billing or resettlement data necessary for determining amounts that might be payable if the FERC's decisions are reversed. Therefore, the Company cannot estimate OTP's exposure at this time from a final order reversing the relevant FERC orders, which could have an adverse effect on the Company's results of operations.

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Contingencies, by their nature, relate to uncertainties that require the Company's management to exercise judgment both in assessing the likelihood a liability has been incurred as well as in estimating the amount of potential loss. The most significant contingencies impacting the Company's consolidated financial statements are those related to environmental remediation, risks associated with indemnification obligations under divestitures of discontinued operations and litigation matters. Should all of these known items result in liabilities being incurred, the loss could be as high as $1.0 million, excluding any liability for RSG charges for which an estimate cannot be made at this time.

In 2014 the Environmental Protection Agency (EPA) published both proposed standards of performance for carbon dioxide (CO_2) emissions from new, reconstructed and modified fossil fuel-fired power plants (New Source Performance Standards), and proposed CO_2 emission guidelines for existing fossil fuel-fired power plants (the Clean Power Plan) under section 111 of the Clean Air Act. The EPA published final rules for each of these proposals on October 23, 2015. Both rules were challenged on legal grounds. On February 9, 2016 the U.S. Supreme Court granted a stay of the Clean Power Plan, pending disposition of petitions for review in the D.C. Circuit. The D.C. Circuit heard oral argument on challenges to the Clean Power Plan on September 27, 2016 before the full court, and a decision was expected in the first half of 2017. However, pursuant to Executive Order 13783, Promoting Energy Independence and Economic Growth, the EPA was directed to consider suspending, revising or rescinding the CO_2 rules discussed above. Thereafter, the EPA issued notices in the Federal Register of its intent to review these rules pursuant to the Executive Order, and it filed motions to stay the pending litigation. The D.C. Circuit subsequently issued orders holding in abeyance the appeals of both the New Source Performance Standards and the Clean Power Plan, pending EPA review. On October 16, 2017 the EPA published a proposed rule to rescind the Clean Power Plan. Therefore, there is uncertainty regarding the future of both rules.

Other

The Company is a party to litigation and regulatory enforcement matters arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2017 will not be material.

9. Short-Term and Long-Term Borrowings

Short-Term Debt

The following table presents the status of the Company's lines of credit as of December 31, 2017 and December 31, 2016:

(in thousands)	Line Limit	In Use on December 31, 2017	Restricted due to Outstanding Letters of Credit	Available on December 31, 2017	Available on December 31, 2016
Otter Tail Corporation Credit Agreement	$ 130,000	$ --	$ --	$ 130,000	$ 130,000
OTP Credit Agreement	170,000	112,371	300	57,329	127,067
Total	$ 300,000	$ 112,371	$ 300	$ 187,329	$ 257,067

Under the Otter Tail Corporation Credit Agreement (as defined below), the maximum amount of debt outstanding in 2017 was $15,169,000 on April 3, 2017 and the average daily balance of debt outstanding during 2017 was $2,305,000. The weighted average interest rate paid on debt outstanding under the Otter Tail Corporation Credit Agreement during 2017 was 2.8% compared with 2.3% in 2016. Under the OTP Credit Agreement (as defined below), the maximum amount of debt outstanding in 2017 was $112,371,000 on December 29, 2017 and the average daily balance of debt outstanding during 2017 was $69,391,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2017 was 2.4% compared with 1.8% in 2016. The maximum amount of consolidated short-term debt outstanding in 2017 was $112,371,000 on December 29, 2017 and the average daily balance of consolidated short-term debt outstanding during 2017 was $71,696,000. The weighted average interest rate on consolidated short-term debt outstanding on December 31, 2017 was 2.7%.

On October 29, 2012 the Company entered into a Third Amended and Restated Credit Agreement (the Otter Tail Corporation Credit Agreement), which is an unsecured $130 million revolving credit facility that may be increased to $250 million on the terms and subject to the conditions described in the Otter Tail Corporation Credit Agreement. On October 31, 2017 the Otter Tail Corporation Credit Agreement was amended to extend its expiration date by one year from October 29, 2021 to October 31, 2022. The Company can draw on this credit facility to refinance certain indebtedness and support its operations and the operations of its subsidiaries. Borrowings under the Otter Tail Corporation Credit Agreement bear interest at LIBOR plus 1.50%, subject to adjustment based on the Company's senior unsecured credit ratings or the issuer rating if a rating is not provided for the senior unsecured credit. The Company is required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The Otter Tail Corporation Credit Agreement

contains a number of restrictions on the Company and the businesses of its wholly owned subsidiary, Varistar and its subsidiaries, including restrictions on the Company's and Varistar's ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of certain other parties and engage in transactions with related parties. The Otter Tail Corporation Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading "Financial Covenants." The Otter Tail Corporation Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the Company's credit ratings. The Company's obligations under the Otter Tail Corporation Credit Agreement are guaranteed by certain of the Company's subsidiaries. Outstanding letters of credit issued by the Company under the Otter Tail Corporation Credit Agreement can reduce the amount available for borrowing under the line by up to $40 million.

On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement), providing for an unsecured $170 million revolving credit facility that may be increased to $250 million on the terms and subject to the conditions described in the OTP Credit Agreement. On October 31, 2017 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2021 to October 31, 2022. OTP can draw on this credit facility to support the working capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed $50 million outstanding at any time. Borrowings under this line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on the ratings of OTP's senior unsecured debt or the issuer rating if a rating is not provided for the senior unsecured debt. OTP is required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading "Financial Covenants." The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. OTP's obligations under the OTP Credit Agreement are not guaranteed by any other party.

Long-Term Debt Issuances and Retirements

2018 Note Purchase Agreement

On November 14, 2017, OTP entered into a Note Purchase Agreement (the 2018 Note Purchase Agreement) with the purchasers named therein, pursuant to which OTP agreed to issue to the purchasers, in a private placement transaction, $100 million aggregate principal amount of OTP's 4.07% Series 2018A Senior Unsecured Notes due February 7, 2048 (the 2018 Notes). The 2018 Notes were issued on February 7, 2018. Proceeds from the 2018 Notes were used to repay $100 million in outstanding borrowings under the OTP Credit Agreement.

OTP may prepay all or any part of the Notes (in an amount not less than 10% of the aggregate principal amount of the Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount so prepaid, together with unpaid accrued interest and a make-whole amount; provided that if no default or event of default exists under the Note Purchase Agreement, any prepayment made by OTP of all of the Notes then outstanding on or after August 7, 2047 will be made without any make-whole amount. The 2018 Note Purchase Agreement also requires OTP to offer to prepay all outstanding Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2018 Note Purchase Agreement) of OTP.

The 2018 Note Purchase Agreement contains a number of restrictions on the business of OTP. These include restrictions on OTP's abilities to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The 2018 Note Purchase Agreement also contains other negative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2018 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The 2018 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event the OTP Credit Agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2018 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the 2018 Notes than any analogous provision contained in the 2018 Note Purchase Agreement (Additional Covenant), then unless waived by the Required Holders (as defined in the 2018 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2018 Note Purchase Agreement. The 2018 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP Credit Agreement, provided that no default or event of default has occurred and is continuing.

2016 Note Purchase Agreement

On September 23, 2016 the Company entered into a Note Purchase Agreement (the 2016 Note Purchase Agreement) with the purchasers named therein, pursuant to which the Company agreed to issue to the purchasers, in a private placement transaction, $80 million aggregate principal amount of its 3.55% Guaranteed Senior Notes due December 15, 2026 (the 2026 Notes). The 2026 Notes were issued on December 13, 2016. The Company's obligations under the 2016 Note Purchase Agreement and the 2026 Notes are guaranteed by its Material Subsidiaries (as defined in the 2016 Note Purchase Agreement, but specifically excluding OTP). The proceeds from the issuance of the 2026 Notes were used to repay the remaining $52,330,000 of the Company's 9.000% Senior Notes due December 15, 2016, and to pay down a portion of the $50 million in funds borrowed in February 2016 under the Company's term loan agreement.

The Company may prepay all or any part of the 2026 Notes (in an amount not less than 10% of the aggregate principal amount of the 2026 Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with unpaid accrued interest and a make-whole amount; provided that if no default or event of default exists under the 2016 Note Purchase Agreement, any optional prepayment made by the Company of all of the 2026 Notes on or after September 15, 2026 will be made without any make-whole amount. The Company is required to offer to prepay all of the outstanding 2026 Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2016 Note Purchase Agreement) of the Company. In addition, if the Company and its Material Subsidiaries sell a "substantial part" of its or their assets and use the proceeds to prepay or retire senior Interest-bearing Debt (as defined in the 2016 Note Purchase Agreement) of the Company and/or a Material Subsidiary in accordance with the terms of the 2016 Note Purchase Agreement, the Company is required to offer to prepay a Ratable Portion (as defined in the 2016 Note Purchase Agreement) of the 2026 Notes held by each holder of the 2026 Notes.

The 2016 Note Purchase Agreement contains a number of restrictions on the business of the Company and the Material Subsidiaries that became effective on execution of the 2016 Note Purchase Agreement. These include restrictions on the Company's and the Material Subsidiaries' abilities to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, engage in transactions with related parties, redeem or pay dividends on the Company's and the Material Subsidiaries' shares of capital stock, and make investments. The 2016 Note Purchase Agreement also contains other negative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2016 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the Company's or the Material Subsidiaries' credit ratings.

Term Loan Agreement

On February 5, 2016 the Company borrowed $50 million under an unsecured Term Loan Agreement (the Term Loan Agreement) at an interest rate based on the 30 day LIBOR plus 90 basis points. The proceeds from the Term Loan Agreement were used to pay down borrowings under the Otter Tail Corporation Credit Agreement that were used to fund the expansion of BTD's Minnesota facilities in 2015 and to fund the September 1, 2015 acquisition of BTD-Georgia. The Company repaid $35 million of the $50 million in the fourth quarter of 2016 and repaid the remaining $15 million during 2017. The Term Loan Agreement terminated on February 5, 2018.

2013 Note Purchase Agreement

On August 14, 2013 OTP entered into a Note Purchase Agreement (the 2013 Note Purchase Agreement) with the purchasers named therein pursuant to which OTP agreed to issue to the purchasers, in a private placement transaction, $60 million aggregate principal amount of OTP's 4.68% Series A Senior Unsecured Notes due February 27, 2029 (the Series A Notes) and $90 million aggregate principal amount of OTP's 5.47% Series B Senior Unsecured Notes due February 27, 2044 (the Series B Notes and, together with the Series A Notes, the Notes). The Notes were issued on February 27, 2014.

The 2013 Note Purchase Agreement states that OTP may prepay all or any part of the Notes (in an amount not less than 10% of the aggregate principal amount of the Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount, provided that if no default or event of default under the 2013 Note Purchase Agreement exists, any optional prepayment made by OTP of (i) all of the Series A Notes then outstanding on or after November 27, 2028 or (ii) all of the Series B Notes then outstanding on or after November 27, 2043, will be made at 100% of the principal prepaid but without any make-whole amount. In addition, the 2013 Note Purchase Agreement states OTP must offer to prepay all of the outstanding Notes at 100% of the principal amount together with unpaid accrued interest in the event of a Change of Control (as defined in the 2013 Note Purchase Agreement) of OTP.

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The 2013 Note Purchase Agreement contains a number of restrictions on the business of OTP, including restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The 2013 Note Purchase Agreement also contains affirmative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2013 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The 2013 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event the OTP Credit Agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2013 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the Notes than any analogous provision contained in the 2013 Note Purchase Agreement (Additional Covenant), then unless waived by the Required Holders (as defined in the 2013 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2013 Note Purchase Agreement. The 2013 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP Credit Agreement, provided that no default or event of default has occurred and is continuing.

2007 and 2011 Note Purchase Agreements

On December 1, 2011, OTP issued $140 million aggregate principal amount of its 4.63% Senior Unsecured Notes due December 1, 2021 pursuant to a Note Purchase Agreement dated as of July 29, 2011 (the 2011 Note Purchase Agreement). OTP also has outstanding its $122 million senior unsecured notes issued in three series consisting of $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (collectively, the 2007 Notes). The 2007 Notes were issued pursuant to a Note Purchase Agreement dated as of August 20, 2007 (the 2007 Note Purchase Agreement). On August 21, 2017 OTP used borrowings under the OTP Credit Agreement to retire the $33 million 5.95%, Series A Senior Unsecured Notes, which had been issued under the 2007 Note Purchase Agreement and matured on August 20, 2017.

The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each states that OTP may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. The 2011 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require OTP to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the 2011 Note Purchase Agreement. The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each also states that OTP must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP. The note purchase agreements contain a number of restrictions on OTP, including restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The note purchase agreements also include affirmative covenants and events of default, and certain financial covenants as described below under the heading "Financial Covenants."

Shelf Registration

On May 11, 2015 the Company filed a shelf registration statement with the SEC under which the Company may offer for sale, from time to time, either separately or together in any combination, equity, debt or other securities described in the shelf registration statement, which expires on May 11, 2018.

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The following tables provide a breakdown of the assignment of the Company's consolidated short-term and long-term debt outstanding as of December 31, 2017 and December 31, 2016:

December 31, 2017 *(in thousands)*	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$ 112,371	$ --	$ 112,371
Long-Term Debt:			
Term Loan, LIBOR plus 0.90%, due February 5, 2018		$ --	$ --
3.55% Guaranteed Senior Notes, due December 15, 2026		80,000	80,000
Senior Unsecured Notes 4.63%, due December 1, 2021	$ 140,000		140,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000		30,000
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000		42,000
Senior Unsecured Notes 4.68%, Series A, due February 27, 2029	60,000		60,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000		50,000
Senior Unsecured Notes 5.47%, Series B, due February 27, 2044	90,000		90,000
North Dakota Development Note, 3.95%, due April 1, 2018		27	27
PACE Note, 2.54%, due March 18, 2021		684	684

Total	$ 412,000	$ 80,711	$ 492,711
Less: Current Maturities net of Unamortized Debt Issuance Costs	--	186	186
Unamortized Long-Term Debt Issuance Costs	1,684	461	2,145
Total Long-Term Debt net of Unamortized Debt Issuance Costs	$ 410,316	$ 80,064	$ 490,380
Total Short-Term and Long-Term Debt (with current maturities)	$ 522,687	$ 80,250	$ 602,937

December 31, 2016 *(in thousands)*	OTP	Otter Tail Corporation	Otter Tail Corporation Consolidated
Short-Term Debt	$ 42,883	$ --	$ 42,883
Long-Term Debt:			
Term Loan, LIBOR plus 0.90%, due February 5, 2018		$ 15,000	$ 15,000
3.55% Guaranteed Senior Notes, due December 15, 2026		80,000	80,000
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	$ 33,000		33,000
Senior Unsecured Notes 4.63%, due December 1, 2021	140,000		140,000
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000		30,000
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000		42,000
Senior Unsecured Notes 4.68%, Series A, due February 27, 2029	60,000		60,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000		50,000
Senior Unsecured Notes 5.47%, Series B, due February 27, 2044	90,000		90,000
North Dakota Development Note, 3.95%, due April 1, 2018		106	106
PACE Note, 2.54%, due March 18, 2021		836	836
Total	$ 445,000	$ 95,942	$ 540,942
Less: Current Maturities net of Unamortized Debt Issuance Costs	32,970	231	33,201
Unamortized Long-Term Debt Issuance Costs	1,861	539	2,400
Total Long-Term Debt net of Unamortized Debt Issuance Costs	$ 410,169	$ 95,172	$ 505,341
Total Short-Term and Long-Term Debt (with current maturities)	$ 486,022	$ 95,403	$ 581,425

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2017 for each of the next five years are:

(in thousands)	2018	2019	2020	2021	2022
Aggregate Amounts of Debt Maturities	$ 186	$ 172	$ 185	$ 140,167	$ 30,000

Financial Covenants

The Company and OTP were in compliance with the financial covenants in these debt agreements as of December 31, 2017.

No Credit or Note Purchase Agreement contains any provisions that would trigger an acceleration of the related debt as a result of changes in the credit rating levels assigned to the related obligor by rating agencies.

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The Company's and OTP's borrowing agreements are subject to certain financial covenants. Specifically:

- Under the Otter Tail Corporation Credit Agreement and the 2016 Note Purchase Agreement, the Company may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00 (each measured on a consolidated basis) as provided in the agreements.
- Under the 2016 Note Purchase Agreement, the Company may not permit its Priority Indebtedness to exceed 10% of its Total Capitalization. The Company had no Priority Indebtedness outstanding as of December 31, 2017.
- Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00.
- Under the 2007 Note Purchase Agreement and the 2011 Note Purchase Agreement, OTP may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, in each case as provided in the related borrowing agreement, and OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement.
- Under the 2013 Note Purchase Agreement and the 2018 Note Purchase Agreement, OTP may not permit its Interest-bearing Debt to exceed 60% of Total Capitalization and may not permit its Priority Indebtedness to exceed 20% of its Total Capitalization, in each case as provided in the related agreement. OTP had no Priority Indebtedness outstanding as of December 31, 2017.

10. Pension Plan and Other Postretirement Benefits

Pension Plan

The Company's noncontributory funded pension plan covers substantially all corporate employees and OTP nonunion employees hired prior to September 1, 2006, and all union employees of OTP hired prior to November 1, 2013, excluding Coyote Station employees. Coyote Station employees hired before January 1, 2009 are covered under the plan. The plan provides 100% vesting after five vesting years of service and for retirement compensation at age 65, with reduced compensation in cases of retirement prior to age 62. The Company reserves the right to discontinue the plan but no change or discontinuance may affect the pensions theretofore vested.

The pension plan has a trustee who is responsible for pension payments to retirees and a separate pension fund manager responsible for managing the plan's assets. An independent actuary assists the Company in performing the necessary actuarial valuations for the plan.

The plan assets consist of common stock and bonds of public companies, U.S. government securities, cash and cash equivalents and alternative investments. None of the plan assets are invested in common stock or debt securities of the Company.

The following table lists components of net periodic pension benefit cost for the year ended December 31:

(in thousands)	2017	2016	2015
Service Cost–Benefit Earned During the Period	$ 5,629	$ 5,518	$ 6,059
Interest Cost on Projected Benefit Obligation	14,139	14,195	13,344
Expected Return on Assets	(19,229)	(19,454)	(18,383)
Amortization of Prior Service Cost:			
From Regulatory Asset	120	189	188
From Other Comprehensive Income[1]	3	5	5
Amortization of Net Actuarial Loss:			
From Regulatory Asset	5,090	5,153	6,676
From Other Comprehensive Income[1]	125	127	171
Net Periodic Pension Cost[2]	$ 5,877	$ 5,733	$ 8,060

[1]*Corporate cost included in Other Nonelectric Expenses.*

[2]*Allocation of Costs:*	*2017*	*2016*	*2015*
Costs included in OTP Capital Expenditures	*$ 1,142*	*$ 1,048*	*$ 1,453*
Costs included in Electric Operation and Maintenance Expenses	*4,594*	*4,547*	*6,406*
Costs included in Other Nonelectric Expenses	*141*	*138*	*201*

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Weighted average assumptions used to determine net periodic pension cost for the year ended December 31:

	2017	2016	2015
Discount Rate	4.60%	4.76%	4.35%
Long-Term Rate of Return on Plan Assets	7.50%	7.75%	7.75%
Rate of Increase in Future Compensation Level	3.00%	3.13%	3.13%

The following table presents amounts recognized in the consolidated balance sheets as of December 31:

(in thousands)	2017	2016
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 21	$ 141
Unrecognized Actuarial Loss	99,360	98,039
Total Regulatory Assets	$ 99,381	$ 98,180
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	$ 9	$ 12
Unrecognized Actuarial Loss	439	406
Total Accumulated Other Comprehensive Loss	$ 448	$ 418
Noncurrent Liability	$ 67,399	$ 60,292

Funded status as of December 31:

(in thousands)	2017	2016
Accumulated Benefit Obligation	$ (316,095)	$ (281,414)
Projected Benefit Obligation	$ (352,718)	$ (314,637)
Fair Value of Plan Assets	285,319	254,345
Funded Status	$ (67,399)	$ (60,292)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's benefit obligations over the two-year period ended December 31, 2017:

(in thousands)	2017	2016
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ 254,346	$ 233,639
Actual Return on Plan Assets	44,181	23,794
Discretionary Company Contributions	--	10,000
Benefit Payments	(13,208)	(13,088)
Fair Value of Plan Assets at December 31	$ 285,319	$ 254,345
Estimated Asset Return	17.8%	10.1%
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 314,637	$ 302,740
Service Cost	5,629	5,518
Interest Cost	14,139	14,195
Benefit Payments	(13,208)	(13,088)
Actuarial Loss	31,521	5,272
Projected Benefit Obligation at December 31	$ 352,718	$ 314,637

Weighted average assumptions used to determine benefit obligations at December 31:

	2017	2016
Discount Rate	3.90%	4.60%
Rate of Increase in Future Compensation Level:		
All participants – prior to 2017		3.00%

S&P Global Market Intelligence

Participants to Age 39	4.50%
Participants Age 40 to Age 49	3.50%
Participants Age 50 and Older	2.75%

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The assumed rate of return on pension fund assets used for the determination of 2018 net periodic pension cost is 7.50%. The assumed long-term rate of return on plan assets is based primarily on asset category studies using historical market return and volatility data with forward looking estimates based on existing financial market conditions and forecasts of capital markets. Modest excess return expectations versus some market indices are incorporated into the return projections based on the actively managed structure of the investment programs and their records of achieving such returns historically. The Company reviews its rate of return on plan asset assumptions annually. The assumptions are largely based on the asset category rate-of-return assumptions developed annually with the Company's pension plan investment advisors, as well as input from actuaries who work with the pension plan and benchmarking to peer companies with similar asset allocation strategies.

Market-related value of plan assets—The Company's expected return on plan assets is determined based on the expected long-term rate of return on plan assets and the market-related value of plan assets.

The Company bases actuarial determination of pension plan expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation calculation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related valuation calculation recognizes gains or losses over a five-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized.

Measurement Dates:	2017	2016
Net Periodic Pension Cost	January 1, 2017	January 1, 2016
End of Year Benefit Obligations	January 1, 2017 projected to December 31, 2017	January 1, 2016 projected to December 31, 2016
Market Value of Assets	December 31, 2017	December 31, 2016

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost in 2018 are:

(in thousands)	2018
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 16
Amortization of Unrecognized Actuarial Loss	7,142
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	--
Amortization of Unrecognized Actuarial Loss	176
Total Estimated Amortization	$ 7,334

Cash flows—The Company had no minimum funding requirement as of December 31, 2017 but made discretionary plan contributions of $20 million as of February 2018.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid out from plan assets:

(in thousands)	2018	2019	2020	2021	2022	Years 2023-2027
	$ 14,384	$ 15,022	$ 15,666	$ 16,336	$ 17,041	$ 93,882

The following objectives guide the investment strategy of the Company's pension plan (the Plan):

- The assets of the Plan will be invested in accordance with all applicable laws in a manner consistent with fiduciary standards including Employee Retirement Income Security Act standards (if applicable). Specifically:
  - The safeguards and diversity that a prudent investor would adhere to must be present in the investment program.
  - All transactions undertaken on behalf of the Plan must be in the best interest of plan participants and their beneficiaries.
- The primary objective of the Plan is to provide a source of retirement income for its participants and beneficiaries.
- The near-term primary financial objective of the Plan is to improve the funded status of the Plan.
- A secondary financial objective is to minimize pension funding and expense volatility where possible.

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The asset allocation strategy developed by the Company's Retirement Plans Administration Committee (the Committee) is based on the current needs of the Plan and the objectives listed above. An asset/liability review is conducted annually or as often as necessary to assess the impact of various asset allocations on funded status and other financial variables. The current needs of the Plan, the overall investment objectives above, the investment preferences and risk tolerance of the Committee and the desired degree of diversification suggest the need for an investment allocation including multiple asset classes.

The asset allocation in the table below contains guideline percentages, at market value, of the total Plan invested in various asset classes. The Permitted Range is a guide and will at times not reflect the actual asset allocation as this will be dictated by market conditions, the independent actions of the Committee and/or Investment Managers and required cash flows to and from the Plan. The Permitted Range anticipates this fluctuation and provides flexibility for the Investment Managers' portfolios to vary around the target without the need for immediate rebalancing. The Investment Manager will proactively monitor the asset allocation and will direct the purchases and sales to remain within the stated ranges.

The policy of the Plan is to invest assets in accordance with the allocations shown below:

	Permitted Range				
Asset Class / PBO Funded Status	**<85% PBO**	**>=85% PBO**	**>=90% PBO**	**>=95% PBO**	**>=100% PBO**

Equity	39% - 59%	34% - 54%	24% - 44%	14% - 34%	0% - 20%
Investment Grade Fixed Income	22% - 42%	30% - 50%	40% - 60%	53% - 73%	70% - 100%
Below Investment Grade Fixed Income*	0% - 15%	0% - 15%	0% - 15%	0% - 10%	0% - 10%
Other**	5% - 20%	5% - 20%	5% - 20%	0% - 15%	0% - 15%

** Includes (but not limited to) High Yield Bond Fund and Emerging Markets Debt funds.*

*** Other category may include cash, alternatives, and/or other investment strategies that may be classified other than equity or fixed income, such as the Dynamic Asset Allocation fund.*

The Company's pension plan asset allocations at December 31, 2017 and 2016, by asset category are as follows:

Asset Allocation	2017	2016
Large Capitalization Equity Securities	23.5%	21.4%
International Equity Securities	18.1%	22.0%
Small and Mid-Capitalization Equity Securities	8.7%	9.0%
Emerging Markets Equity Fund	5.5%	0.0%
SEI Dynamic Asset Allocation Fund	5.0%	5.4%
Equity Securities	60.8%	57.8%
Fixed-Income Securities and Cash	35.2%	34.3%
Other – SEI Energy Debt Collective Fund	4.0%	4.1%
Other – SEI Special Situation Collective Investment Trust	0.0%	3.8%
	100.0%	100.0%

The following table presents the Company's pension fund assets measured at fair value and included in Level 1 of the fair value hierarchy and assets measured using the NAV practical expedient to fair valuation as of December 31:

(in thousands)	2017	2016
Assets in Level 1 of the Fair Value Hierarchy	$ 273,999	$ 234,303
SEI Energy Debt Collective Fund at NAV	11,320	10,441
SEI Special Situation Collective Investment Trust Fund at NAV	--	9,601
Total Assets	$ 285,319	$ 254,345

Fair Value Measurements of Pension Fund Assets

ASC 715, *Compensation – Retirement Benefits*, requires disclosures about pension plan assets identified by the three levels of the fair value hierarchy established by ASC 820-10-35.

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The following table presents, the Company's pension fund assets measured at fair value and included in Level 1 of the fair value hierarchy as of December 31:

(in thousands)	2017	2016
Large Capitalization Equity Securities Mutual Fund	$ 66,946	$ 54,483
International Equity Securities Mutual Funds	51,636	55,916
Small and Mid-Capitalization Equity Securities Mutual Fund	24,848	23,011
Emerging Markets Equity Fund	15,824	--
SEI Dynamic Asset Allocation Mutual Fund	14,371	13,622
Fixed Income Securities Mutual Funds	100,373	87,268
Cash Management – Money Market Fund	1	3
Total Assets	$ 273,999	$ 234,303

The investments held by the SEI Energy Debt Collective Fund on December 31, 2017 and 2016 consist mainly of below investment grade high yielding bonds and loans of U.S. energy companies which trade at a discount to fair value. Redemptions are allowed semi-annually with a 95-day notice period, subject to fund director consent and certain gate, holdback and suspension restrictions. Subscriptions are allowed monthly with a three-year lock up on subscriptions. The Company invested $10.0 million in the SEI Energy Debt Fund in July 2015. The fund's assets are valued in accordance with valuations reported by the fund's sub-advisor or the fund's underlying investments or other independent third party sources, although SEI in its discretion may use other valuation methods, subject to compliance with ERISA (as applicable). The fund's assets are valued as of the close of business on the last business day of each calendar month and are available 30 days after the end of a calendar quarter. On an annual basis, as determined by the investment manager in its sole discretion, an independent valuation agent is retained to provide a valuation of the illiquid assets of the fund and of any other asset of the fund, as determined by the investment manager in its sole discretion. The Company reviews and verifies the reasonableness of the year-end valuations.

Executive Survivor and Supplemental Retirement Plan (ESSRP)

The ESSRP is an unfunded, nonqualified benefit plan for executive officers and certain key management employees. The ESSRP provides defined benefit payments to these employees on their retirements for life or to their beneficiaries on their deaths for a 15-year postretirement period. Life insurance carried on certain plan participants is payable to the Company on the employee's death. There are no plan assets in this nonqualified benefit plan due to the nature of the plan.

The following table lists components of net periodic pension benefit cost for the year ended December 31:

(in thousands)	2017	2016	2015
Service Cost–Benefit Earned During the Period	$ 290	$ 252	$ 189
Interest Cost on Projected Benefit Obligation	1,686	1,667	1,523
Amortization of Prior Service Cost:			
From Regulatory Asset	16	16	16
From Other Comprehensive Income[1]	38	38	38
Amortization of Net Actuarial Loss:			
From Regulatory Asset	285	293	334
From Other Comprehensive Income[2]	440	446	602
Net Periodic Pension Cost[3]	$ 2,755	$ 2,712	$ 2,702

[1] *Amortization of Prior Service Costs from Other Comprehensive Income Charged to:*

Electric Operation and Maintenance Expenses	*$ 15*	*$ 15*	*$ 15*
Other Nonelectric Expenses	*23*	*23*	*23*
[2]Amortization of Net Actuarial Loss from Other Comprehensive Income Charged to:			
Electric Operation and Maintenance Expenses	*$ 265*	*$ 272*	*$ 310*
Other Nonelectric Expenses	*175*	*174*	*292*

[3]ESSRP costs are not capitalized.

Weighted average assumptions used to determine net periodic pension cost for the year ended December 31:

	2017	2016	2015
Discount Rate	4.60%	4.76%	4.35%
Rate of Increase in Future Compensation Level	3.00%	3.13%	3.15%

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The following table presents amounts recognized in the consolidated balance sheets as of December 31:

(in thousands)	2017	2016
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 40	$ 58
Unrecognized Actuarial Loss	3,229	2,890
Total Regulatory Assets	$ 3,269	$ 2,948
Projected Benefit Obligation Liability – Net Amount Recognized	$ (42,308)	$ (37,335)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	$ 98	$ 134
Unrecognized Actuarial Loss	9,024	5,915
Total Accumulated Other Comprehensive Loss	$ 9,122	$ 6,049

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations over the two-year period ended December 31, 2017 and a statement of the funded status as of December 31 of both years:

(in thousands)	2017	2016
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ --	$ --
Actual Return on Plan Assets	--	--
Employer Contributions	1,175	1,188
Benefit Payments	(1,175)	(1,188)
Fair Value of Plan Assets at December 31	$ --	$ --
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 37,335	$ 35,811
Service Cost	290	252
Interest Cost	1,686	1,667
Benefit Payments	(1,175)	(1,188)
Plan Amendments	--	--
Actuarial Loss	4,172	793
Projected Benefit Obligation at December 31	$ 42,308	$ 37,335

Weighted average assumptions used to determine benefit obligations at December 31:

	2017	2016
Discount Rate	3.85%	4.60%
Rate of Increase in Future Compensation Level:	2.92%	3.00%

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost for the ESSRP in 2018 are:

(in thousands)	2018
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 16
Amortization of Unrecognized Actuarial Loss	267
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	38
Amortization of Unrecognized Actuarial Loss	661
Total Estimated Amortization	$ 982

Cash flows—The ESSRP is unfunded and has no assets; contributions are equal to the benefits paid to plan participants. The following benefit payments, which reflect future service, as appropriate, are expected to be paid:

(in thousands)	2018	2019	2020	2021	2022	Years 2023-2027
	$ 1,568	$ 1,612	$ 1,576	$ 1,670	$ 2,255	$ 13,775

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Other Postretirement Benefits

The Company provides a portion of health insurance and life insurance benefits for retired OTP and corporate employees. Substantially all of the Company's electric utility and corporate employees may become eligible for health insurance benefits if they reach age 55 and have 10 years of service. There are no plan assets. The following table lists components of net periodic postretirement benefit cost for the year ended December 31:

(in thousands)	2017	2016	2015
Service Cost–Benefit Earned During the Period	$ 1,425	$ 1,301	$ 1,297
Interest Cost on Projected Benefit Obligation	2,712	2,503	2,097
Amortization of Prior Service Cost			
From Regulatory Asset	(4)	134	205
From Other Comprehensive Income[1]	4	3	5
Amortization of Net Actuarial Loss			
From Regulatory Asset	936	379	--
From Other Comprehensive Income[1]	19	9	--
Net Periodic Postretirement Benefit Cost[2]	$ 5,092	$ 4,329	$ 3,604
Effect of Medicare Part D Subsidy	$ (561)	$ (923)	$ (1,487)

[1]*Corporate cost included in Other Nonelectric Expenses*

[2]*Allocation of Cost:*	*2017*	*2016*	*2015*
Cost included in OTP Capital Expenditures	*$ 989*	*$ 792*	*$ 650*
Cost included in Electric Operation and Maintenance Expenses	*3,981*	*3,433*	*2,864*
Cost included in Other Nonelectric Expenses	*122*	*104*	*90*

Weighted average assumptions used to determine net periodic postretirement benefit cost for the year ended December 31:

	2017	2016	2015
Discount Rate	4.46%	4.57%	4.20%

The following table presents amounts recognized in the consolidated balance sheets as of December 31:

(in thousands)	2017	2016
Regulatory Asset:		
Unrecognized Prior Service Cost	$ --	$ (4)
Unrecognized Net Actuarial Loss	18,927	13,586
Net Regulatory Asset	$ 18,927	$ 13,582
Projected Benefit Obligation Liability – Net Amount Recognized	$ (69,774)	$ (62,571)
Accumulated Other Comprehensive (Income) Loss:		
Unrecognized Prior Service Cost	$ --	$ 4
Unrecognized Net Actuarial Gain	(111)	(171)
Accumulated Other Comprehensive Income	$ (111)	$ (167)

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The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations and accrued postretirement benefit cost over the two-year period ended December 31, 2017:

(in thousands)	2017	2016
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ --	$ --
Actual Return on Plan Assets	--	--
Company Contributions	3,290	2,825
Benefit Payments (Net of Medicare Part D Subsidy)	(6,534)	(5,908)
Participant Premium Payments	3,244	3,083
Fair Value of Plan Assets at December 31	$ --	$ --
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 62,571	$ 48,730
Service Cost (Net of Medicare Part D Subsidy)	1,425	1,301
Interest Cost (Net of Medicare Part D Subsidy)	2,712	2,503
Benefit Payments (Net of Medicare Part D Subsidy)	(6,534)	(5,908)
Participant Premium Payments	3,244	3,083
Actuarial Loss	6,356	12,862
Projected Benefit Obligation at December 31	$ 69,774	$ 62,571
Reconciliation of Accrued Postretirement Cost:		
Accrued Postretirement Cost at January 1	$ (49,156)	$ (47,652)
Expense	(5,092)	(4,329)
Net Company Contribution	3,290	2,825
Accrued Postretirement Cost at December 31	$ (50,958)	$ (49,156)

Weighted average assumptions used to determine benefit obligations at December 31:

	2017	2016
Discount Rate	3.81%	4.46%

Assumed healthcare cost-trend rates as of December 31:

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	2017	2016
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	5.85%	6.01%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	6.03%	6.23%
Rate to Which the Cost-Trend Rate is Assumed to Decline	4.50%	4.50%
Year the Rate Reaches the Ultimate Trend Rate	2038	2038

Assumed healthcare cost-trend rates have a significant effect on the amounts reported for healthcare plans. A one-percentage-point change in assumed healthcare cost-trend rates for 2017 would have the following effects:

(in thousands)	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	$ 9,301	$ (7,692)
Effect on Total of Service and Interest Cost	$ 731	$ (601)
Effect on Expense	$ 1,589	$ (1,500)

Measurement Dates:	2017	2016
Net Periodic Postretirement Benefit Cost	January 1, 2017	January 1, 2016
End of Year Benefit Obligations	January 1, 2017 projected to December 31, 2017	January 1, 2016 projected to December 31, 2016

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The estimated net amounts of unrecognized prior service cost to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic postretirement benefit cost in 2018 are:

(in thousands)	2018
Decrease in Regulatory Assets:	
Amortization of Unrecognized Actuarial Loss	$ 1,649
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Actuarial Loss	41
Total Estimated Amortization	$ 1,690

Cash flows—The Company expects to contribute $4.0 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2018. The Company expects to receive a Medicare Part D subsidy from the Federal government of approximately $0.4 million in 2018. The following benefit payments, which reflect expected future service, as appropriate, net of expected Medicare Part D subsidy receipts and participant premium payments, are expected to be paid:

(in thousands)	2018	2019	2020	2021	2022	Years 2023-2027
	$ 3,986	$ 4,107	$ 4,133	$ 4,218	$ 4,327	$ 21,089

401K Plan

The Company sponsors a 401K plan for the benefit of all corporate and subsidiary company employees. Contributions made to these plans by the Company and its subsidiary companies included in continuing operations totaled $4,211,000 for 2017, $3,877,000 for 2016 and $3,602,000 for 2015.

Employee Stock Ownership Plan

The Company has a stock ownership plan for the benefit of all its electric utility employees. Contributions made by the Company were $612,000 for 2017, $647,000 for 2016 and $674,000 for 2015.

11. Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Cash Equivalents—The carrying amount approximates fair value because of the short-term maturity of those instruments.

Short-Term Debt—The carrying amount approximates fair value because the debt obligations are short-term and the balances outstanding as of December 31, 2017 and December 31, 2016 related to the OTP Credit Agreement were subject to a variable interest rate of LIBOR plus 1.25%, which approximates market rates.

Long-Term Debt including Current Maturities—The fair value of the Company's and OTP's long-term debt is estimated based on the current market indications of rates available to the Company for the issuance of debt. The Company's long-term debt subject to variable interest rates on December 31, 2016 approximated fair value. The fair value measurements of the Company's long-term debt issues fall into level 2 of the fair value hierarchy set forth in ASC 820.

	December 31, 2017		December 31, 2016	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Cash Equivalents	$ 16,216	$ 16,216	$ --	$ --
Short-Term Debt	(112,371)	(112,371)	(42,883)	(42,883)
Long-Term Debt including Current Maturities	(490,566)	(543,691)	(538,542)	(583,835)

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12. Property, Plant and Equipment

(in thousands)	December 31, 2017	December 31, 2016
Electric Plant in Service		
Production	$ 897,732	$ 891,330
Transmission	500,352	410,679
Distribution	482,867	466,285
General	100,067	92,063
Electric Plant in Service	1,981,018	1,860,357
Construction Work in Progress	132,556	149,997
Total Gross Electric Plant	2,113,574	2,010,354
Less Accumulated Depreciation and Amortization	662,431	622,657
Net Electric Plant	$ 1,451,143	$ 1,387,697
Nonelectric Operations Plant		
Equipment	$ 160,263	$ 155,809
Buildings and Leasehold Improvements	52,280	51,323
Land	4,394	4,694
Nonelectric Operations Plant	216,937	211,826
Construction Work in Progress	8,511	3,264
Total Gross Nonelectric Plant	225,448	215,090
Less Accumulated Depreciation and Amortization	136,988	125,562
Net Nonelectric Operations Plant	$ 88,460	$ 89,528
Net Plant	$ 1,539,603	$ 1,477,225

The estimated service lives for rate-regulated properties is 5 to 82 years. For nonelectric property the estimated useful lives are from 3 to 40 years.

	Service Life Range	
(years)	Low	High
Electric Fixed Assets:		
Production Plant	9	82
Transmission Plant	42	70
Distribution Plant	5	68
General Plant	5	50
Nonelectric Fixed Assets:		
Equipment	3	12
Buildings and Leasehold Improvements	7	40

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13. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2017, 2016 and 2015) to net income before total income tax expense for the following reasons:

(in thousands)	2017	2016	2015
Tax Computed at Federal Statutory Rate – Continuing Operations	$ 34,707	$ 28,741	$ 28,081
Increases (Decreases) in Tax from:			
Federal Production Tax Credits (PTCs)	(7,527)	(7,175)	(6,962)
State Income Taxes Net of Federal Income Tax Expense	4,341	2,848	4,945
Section 199 Domestic Production Activities Deduction	(1,471)	(482)	--
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(850)	(850)	(850)
Corporate-owned Life Insurance	(845)	(680)	(167)
Excess Tax deduction - Equity Method Stock Awards	(751)	--	--
Employee Stock Ownership Plan Dividend Deduction	(509)	(537)	(560)
Allowance for Funds Used During Construction – Equity	(322)	(280)	(426)
Investment Tax Credit Amortization	(164)	(350)	(571)
Differences Reversing in Excess of Federal Rates	551	77	(1,143)
Permanent and Other Differences	(1,873)	(1,231)	(705)
Effect of TCJA Tax Rate Reduction on Value of Net Deferred Tax Assets	1,756	--	--
Total Income Tax Expense – Continuing Operations	$ 27,043	$ 20,081	$ 21,642
Income Tax Expense – Discontinued Operations – U.S.	213	138	2,991
Income Tax Expense – Continuing and Discontinued Operations	$ 27,256	$ 20,219	$ 24,633
Overall Effective Federal, State and Foreign Income Tax Rate	27.3%	24.5%	29.3%
Income Tax Expense From Continuing Operations Includes the Following:			
Current Federal Income Taxes	$ 4,581	$ 1,070	$ 211
Current State Income Taxes	1,154	1,211	1
Deferred Federal Income Taxes	25,320	23,586	23,050
Deferred State Income Taxes	4,529	2,589	6,763
Federal PTCs	(7,527)	(7,175)	(6,962)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(850)	(850)	(850)
Investment Tax Credit Amortization	(164)	(350)	(571)
Total	$ 27,043	$ 20,081	$ 21,642
Total Income Before Income Taxes – Continuing and Discontinued Operations	$ 99,695	$ 82,540	$ 83,978

The Company's deferred tax assets and liabilities were composed of the following on December 31:

(in thousands)	2017	2016
Deferred Tax Assets		
Federal PTCs	$ 40,614	$ 43,433
Regulatory Tax Liability	39,465	2,422
North Dakota Wind Tax Credits	32,962	32,962
Benefit Liabilities	32,328	44,381
Retirement Benefits Liabilities	31,894	38,390
Cost of Removal	21,800	31,636
Differences Related to Property	6,499	9,876
Net Operating Loss Carryforward	3,203	3,865
Vacation Accrual	1,844	2,725
Investment Tax Credits	515	818
Other	668	5,371
Total Deferred Tax Assets	$ 211,792	$ 215,879
Deferred Tax Liabilities		
Differences Related to Property	$ (257,906)	$ (371,761)
Retirement Benefits Regulatory Asset	(31,894)	(38,390)
Excess Tax over Book Pension	(14,077)	(15,509)
North Dakota Wind Tax Credits	(4,112)	(3,654)
Impact of State Net Operating Losses on Federal Taxes	(673)	(1,352)
Other	(3,631)	(11,804)
Total Deferred Tax Liabilities	$ (312,293)	$ (442,470)
Deferred Income Taxes	$ (100,501)	$ (226,591)

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Federal PTCs are earned as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP's kwh generation from its wind turbines eligible for PTCs increased 4.4% in 2017 compared with 2016. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

Schedule of expiration of tax credits and tax net operating losses available as of December 31, 2017:

(in thousands)	Amount	2022-2031	2032-2037	2038-2043
United States				
Federal Tax Credits	$ 43,238	$ --	$ 43,238	$ --
State Net Operating Losses	3,203	2,339	864	--
State Tax Credits	33,568	376	231	32,961

The following table summarizes the activity related to the Company's unrecognized tax benefits:

(in thousands)	2017	2016	2015
Balance on January 1	$ 891	$ 468	$ 222
Increases Related to Tax Positions for Prior Years	28	406	236
Decreases Related to Tax Positions for Prior Years	(378)	--	--
Increases Related to Tax Positions for Current Year	143	114	10
Uncertain Positions Resolved During Year	--	(97)	--
Balance on December 31	$ 684	$ 891	$ 468

The balance of unrecognized tax benefits as of December 31, 2017 would reduce the Company's effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2017 is not expected to change significantly within the next 12 months. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes in the Company's consolidated statement of income. There was no amount accrued for interest on tax uncertainties as of December 31, 2017.

The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state income tax returns. As of December 31, 2017, with limited exceptions, the Company is no longer subject to examinations by taxing authorities for tax years prior to 2014 for federal and North Dakota state income taxes and for years prior to 2013 for Minnesota state income taxes.

TCJA

In December 2017 the TCJA was enacted. The TCJA includes a number of changes to existing U.S. tax laws that impact the Company, most notably a reduction of the federal corporate income tax rate from 35% to 21% for tax years beginning after December 31, 2017.

The Company measures deferred tax assets and liabilities using enacted tax rates that will apply in the years in which the temporary differences are expected to be recovered or paid. Accordingly, the Company's deferred tax assets and liabilities were remeasured to reflect the reduction in the U.S. corporate income tax rate from 35% to 21%. The revaluation for OTP required the creation of a regulatory liability and an offsetting reduction in deferred tax liability. This regulatory liability will generally be amortized over the remaining life of the related assets. On a consolidated financial statement basis, the revaluation resulted in a one-time, non-cash, income tax expense of approximately $1.8 million in 2017. The impacts of the TCJA adjustments to deferred taxes and regulatory liabilities are provided in the reconciliation below:

(in thousands)	Deferred Tax Liability	Deferred Tax Regulatory Liability
Balance on January 1, 2017	$ 226,591	$ 818
Change due to 2017 Accruals and Amortizations	20,012	376
TCJA Deferred Tax Valuation Adjustment	(109,072)	109,072
Tax Effect on TCJA Deferred Tax Valuation Adjustment	(38,786)	38,786
TCJA Adjustment to Income Tax Expense	1,756	--

Balance on December 31, 2017	$	100,501	$	149,052

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The Company recognized the income tax effects of the TCJA in its 2017 consolidated financial statements in accordance with Staff Accounting Bulletin No. 118, which provides SEC staff guidance for the application of ASC Topic 740, *Income Taxes*, in the reporting period in which the TCJA was signed into law. Current estimates may be revised and are subject to change due, in part, to complexities and uncertainties associated with the TCJA. While the Company is able to make reasonable estimates of the impact of the TCJA for the reduction in the federal corporate tax rate, changes to bonus depreciation and consequences on the Company's regulatory liabilities, the final impact of the TCJA may differ from these estimates due to, among other things, changes in the Company's interpretations and assumptions and additional guidance that may be issued by the U.S. Internal Revenue Service, rate regulators or the FASB.

14. Asset Retirement Obligations (AROs)

The Company's AROs are related to OTP's coal-fired generation plants and its 92 wind turbines located in North Dakota. The AROs include items such as site restoration, closure of ash pits, and removal of certain structures, generators, asbestos and storage tanks. The Company has legal obligations associated with the retirement of a variety of other long-lived tangible assets used in electric operations where the estimated settlement costs are individually and collectively immaterial. The Company has no assets legally restricted for the settlement of any of its AROs.

OTP recorded no new AROs in 2017.

Reconciliations of carrying amounts of the present value of the Company's legal AROs, capitalized asset retirement costs and related accumulated depreciation and a summary of settlement activity for the years ended December 31, 2017 and 2016 are presented in the following table:

(in thousands)	2017	2016
Asset Retirement Obligations		
Beginning Balance	$ 8,341	$ 8,084
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	(103)
Accrued Accretion	378	360
Settlements	--	--
Ending Balance	$ 8,719	$ 8,341
Asset Retirement Costs Capitalized		
Beginning Balance	$ 2,983	$ 3,086
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	(103)
Settlements	--	--
Ending Balance	$ 2,983	$ 2,983
Accumulated Depreciation – Asset Retirement Costs Capitalized		
Beginning Balance	$ 795	$ 673
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Depreciation Expense	120	122
Settlements	--	--
Ending Balance	$ 915	$ 795
Settlements	None	None
Original Capitalized Asset Retirement Cost – Retired	$ --	$ --
Accumulated Depreciation	--	--
Asset Retirement Obligation	$ --	$ --
Settlement Cost	--	--
Gain on Settlement – Deferred Under Regulatory Accounting	$ --	$ --

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15. Discontinued Operations

On April 30, 2015 the Company sold Foley for $12.0 million in cash, plus $6.3 million in adjustments for working capital and other related items received in October 2015, less $1.0 million in selling expenses. On February 28, 2015 the Company sold the assets of AEV, Inc. for $22.3 million in cash, plus $0.6 million in adjustments for working capital and fixed assets received in October 2015, less $0.8 million in selling expenses. Foley and AEV, Inc. were formerly included in the Company's Construction segment.

On February 8, 2013 the Company completed the sale of substantially all the assets of its dock and boatlift company, formerly included in the Company's Manufacturing segment. On November 30, 2012 the Company completed the sale of the assets of the Company's wind tower manufacturing business. This business was the only remaining entity in the Company's former Wind Energy segment.

The Company's Wind Energy and Construction segments were eliminated as a result of the sales of its wind tower manufacturing business, Foley and AEV, Inc. The financial position, results of operations and cash flows of Foley, AEV, Inc., the Company's wind tower manufacturing business and its dock and boatlift company are reported as discontinued operations in the Company's consolidated financial statements.

Following are summary presentations of the results of discontinued operations for the years ended December 31, 2017, 2016 and 2015:

	For the Year Ended December 31, 2017		
	Wind	Dock and	Intercompany

(in thousands)	Foley	AEV, Inc.	Tower Business	Boatlift Business	Transactions Adjustment	Total
Operating Expenses	$ 233	$ --	$ (460)	$ (306)	$ --	$ (533)
Income Tax (Benefit) Expense	(93)	--	184	122	--	213
Net (Loss) Income	$ (140)	$ --	$ 276	$ 184	$ --	$ 320

	For the Year Ended December 31, 2016					
(in thousands)	Foley	AEV, Inc.	Wind Tower Business	Dock and Boatlift Business	Intercompany Transactions Adjustment	Total
Operating Expenses	$ 250	$ --	$ (757)	$ 85	$ --	$ (422)
Income Tax (Benefit) Expense	(136)	5	303	(34)	--	138
Net (Loss) Income	$ (114)	$ (5)	$ 454	$ (51)	$ --	$ 284

	For the Year Ended December 31, 2015					
(in thousands)	Foley	AEV, Inc.	Wind Tower Business	Dock and Boatlift Business	Intercompany Transactions Adjustment	Total
Operating Revenues	$ 21,625	$ 2,998	$ --	$ --	$ --	$ 24,623
Operating Expenses	26,839	4,532	(462)	966	(240)	31,635
Asset Impairment Charge	1,000	--	--	--	--	1,000
Interest Expense	177	27	--	--	(204)	--
Other Income (Deductions)	(42)	2	111	--	(2)	69
Income Tax (Benefit) Expense	(921)	(638)	229	(386)	177	(1,539)
Net (Loss) Income from Operations	(5,512)	(921)	344	(580)	265	(6,404)
(Loss) Gain on Disposition Before Taxes	(204)	11,894	--	--	--	11,690
Income Tax (Benefit) Expense on Disposition	(227)	4,757	--	--	--	4,530
Net Gain on Disposition	23	7,137	--	--	--	7,160
Net (Loss) Income	$ (5,489)	$ 6,216	$ 344	$ (580)	$ 265	$ 756

Foley and AEV, Inc. entered into fixed-price construction contracts. Revenues under these contracts were recognized on a percentage-of-completion basis. The method used to determine the progress of completion was based on the ratio of costs incurred to total estimated costs on construction projects. An increase in estimated costs on one large job in progress at Foley in excess of previous period cost estimates resulted in pretax charges of $4.4 million in 2015. In the first quarter of 2015, Foley recorded a $1.0 million goodwill impairment charge based on adjustments to the carrying value of Foley.

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Following are summary presentations of the major components of assets and liabilities of discontinued operations as of December 31, 2017 and December 31, 2016:

	December 31, 2017		
(in thousands)	Wind Tower Business	Dock and Boatlift Business	Total
Current Liabilities	$ 130	$ 362	$ 492
Liabilities of Discontinued Operations	$ 130	$ 362	$ 492

	December 31, 2016		
(in thousands)	Wind Tower Business	Dock and Boatlift Business	Total
Current Liabilities	$ 589	$ 774	$ 1,363
Liabilities of Discontinued Operations	$ 589	$ 774	$ 1,363

Included in current liabilities of discontinued operations are warranty reserves. Details regarding the warranty reserves follow:

(in thousands)	2017	2016
Warranty Reserve Balance, January 1	$ 1,369	$ 2,103
Additional Provision for Warranties Made During the Year	--	--
Settlements Made During the Year	(112)	(24)
Decrease in Warranty Estimates for Prior Years	(760)	(710)
Warranty Reserve Balance, December 31	$ 497	$ 1,369

The warranty reserve balances as of December 31, 2017 relate entirely to products produced by the Company's former wind tower and dock and boatlift manufacturing companies. Certain products sold by the companies carried one to fifteen year warranties. Although the assets of these companies have been sold and their operating results are reported under discontinued operations in the Company's consolidated statements of income, the Company retains responsibility for warranty claims related to the products they produced prior to the sales of these companies.

Expenses associated with remediation activities of these companies could be substantial. For wind towers, the potential exists for multiple claims based on one defect repeated throughout the production process or for claims where the cost to repair or replace the defective part is highly disproportionate to the original cost of the part. For example, if the Company is required to cover remediation expenses in addition to regular warranty coverage, the Company could be required to accrue additional expenses and experience additional unplanned cash expenditures which could adversely affect the Company's consolidated net income and financial condition.

16. Subsequent Events

Stock Incentive Awards

On February 5, 2018 the following stock incentive awards were granted to officers under the 2014 Incentive Plan:

Award	Shares/Units Granted	Weighted Average Grant-Date Fair Value per Award	Vesting
Restricted Stock Units Granted	15,200	$ 41.325	25% per year through February 6, 2022
Stock Performance Awards Granted	54,000	$ 35.73	December 31, 2020

The vesting of restricted stock units is accelerated in the event of a change in control, disability, death or retirement, subject to proration in certain cases. All restricted stock units granted to executive officers are eligible to receive dividend equivalent payments on all unvested awards over the awards respective vesting periods, subject to forfeiture under the terms of the restricted stock unit award agreements. The grant-date fair value of each restricted stock unit was the average of the high and low market price per share on the date of grant.

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Under the performance share awards the aggregate award for performance at target is 54,000 shares. For target performance the participants would earn an aggregate of 27,000 common shares for achieving the target set for the Company's 3-year average adjusted return on equity. The participants would also earn an aggregate of 27,000 common shares based on the Company's total shareholder return relative to the total shareholder return of the companies that comprise the EEI Index over the performance measurement period of January 1, 2018 through December 31, 2020, with the beginning and ending share values based on the average closing price of a share of the Company's common stock for the 20 trading days immediately following January 1, 2018 and the average closing price for the 20 trading days immediately preceding January 1, 2021. Actual payment may range from zero to 150% of the target amount, or up to 81,000 common shares. There are no voting or dividend rights related to these shares until the shares, if any, are issued at the end of the performance measurement period. The terms of these awards are such that the entire award will be classified and accounted for as equity, as required under ASC 718, and will be measured over the performance period based on the grant-date fair value of the award. The grant-date fair value of each performance share award was determined using a Monte Carlo fair valuation simulation model.

Under the 2018 Performance Award Agreements, payment and the amount of payment in the event of retirement, resignation for good reason or involuntary termination without cause is to be made at the end of the performance period based on actual performance, subject to proration in certain cases, except that the payment of performance awards granted to an officer who is party to an Executive Employment Agreement with the Company is to be made at target at the date of any such event.

The end of the period over which compensation expense is recognized for the above share-based awards for the individual grantees is the shorter of the indicated vesting period for the respective awards or the date the grantee becomes eligible for retirement as defined in their award agreement.

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Supplementary Financial Information

Quarterly Information (not audited)

Because of changes in the number of common shares outstanding and the impact of diluted shares, the sum of the quarterly earnings per common share may not equal total earnings per common share.

Three Months Ended	March 31		June 30		September 30		December 31	
(in thousands, except per share data)	2017	2016	2017	2016	2017	2016	2017	2016
Operating Revenues–Continuing Operations	$ 214,117	$ 206,242	$ 212,086	$ 203,482	$ 216,457	$ 197,175	$ 206,690	$ 196,640
Operating Income–Continuing Operations	$ 32,801	$ 27,576	$ 29,589	$ 27,083	$ 31,609	$ 27,284	$ 32,135	$ 29,156
Net Income (Loss):								
Continuing Operations	$ 19,529	$ 14,490	$ 16,717	$ 15,556	$ 17,773	$ 14,594	$ 18,100	$ 17,397
Discontinued Operations	$ 56	$ 30	$ 61	$ 119	$ (39)	$ 22	$ 242	$ 113
Total Net Income	$ 19,585	$ 14,520	$ 16,778	$ 15,675	$ 17,734	$ 14,616	$ 18,342	$ 17,510
Basic Earnings Per Share:								
Continuing Operations	$ .50	$ .38	$ .43	$ .41	$ .45	$ .38	$ .45	$ .45
Discontinued Operations	$ --	$ --	$ --	$ --	$ --	$ --	$ .01	$ --
Total Basic Earnings Per Share	$ .50	$ .38	$ .43	$ .41	$ .45	$ .38	$ .46	$ .45
Diluted Earnings Per Share:								
Continuing Operations	$ .49	$ .38	$ .42	$ .41	$ .45	$ .37	$ .45	$ .44
Discontinued Operations	$ --	$ --	$ --	$ --	$ --	$ --	$ .01	$ --
Total Diluted Earnings Per Share	$ .49	$ .38	$ .42	$ .41	$ .45	$ .37	$ .46	$ .44
Dividends Declared Per Common Share	$ .3200	$ .3125	$ .3200	$ .3125	$ .3200	$ .3125	$ .3200	$ .3125
Price Range:								
High	40.80	29.73	41.95	33.50	44.50	36.42	48.65	42.55
Low	35.65	25.80	36.45	27.77	38.75	32.89	43.30	33.08
Average Number of Common Shares Outstanding--Basic	39,351	37,937	39,463	38,179	39,508	38,833	39,508	39,236
Average Number of Common Shares Outstanding--Diluted	39,641	38,045	39,702	38,321	39,795	39,006	39,855	39,552

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Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosures Controls and Procedures. Under the supervision and with the participation of the Company's management, including the Chief Executive Officer

and the Chief Financial Officer, the Company evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)) as of December 31, 2017, the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2017.

Changes in Internal Control over Financial Reporting. There were no changes in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) under the Exchange Act) during the fourth quarter ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report Regarding Internal Control Over Financial Reporting. Management is responsible for the preparation and integrity of the consolidated financial statements and representations in this Annual Report on Form 10-K. The consolidated financial statements of the Company have been prepared in conformity with generally accepted accounting principles applied on a consistent basis and include some amounts that are based on informed judgments and best estimates and assumptions of management.

In order to assure the consolidated financial statements are prepared in conformance with generally accepted accounting principles, management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). These internal controls are designed only to provide reasonable assurance, on a cost-effective basis, that transactions are carried out in accordance with management's authorizations and assets are safeguarded against loss from unauthorized use or disposition.

Management has completed its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control - Integrated Framework* (*2013*) to conduct the required assessment of the effectiveness of the Company's internal control over financial reporting. Based on this assessment, management concluded that, as of December 31, 2017, the Company's internal control over financial reporting was effective based on those criteria. The Company's independent registered public accounting firm, Deloitte & Touche LLP, has audited the Company's consolidated financial statements included in this Annual Report on Form 10-K and issued an attestation report on the Company's internal control over financial reporting.

Attestation Report of Independent Registered Public Accounting Firm. The attestation report of Deloitte & Touche LLP, the Company's independent registered public accounting firm, regarding the Company's internal control over financial reporting is provided on page 60.

Item 9B. OTHER INFORMATION

None.

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PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item regarding Directors is incorporated by reference to the information under "Election of Directors" in the Company's definitive Proxy Statement for the 2018 Annual Meeting. The information regarding executive officers and family relationships is set forth in Item 3A hereto. The information regarding Section 16 reporting is incorporated by reference to the information under "Security Ownership of Directors and Officers - Section 16(a) Beneficial Ownership Reporting Compliance" in the Company's definitive Proxy Statement for the 2018 Annual Meeting. The information required by this Item regarding the Company's procedures for recommending nominees to the board of directors is incorporated by reference to the information under "Meetings and Committees of the Board of Directors – Corporate Governance Committee" in the Company's definitive Proxy Statement for the 2018 Annual Meeting. The information required by this Item in regard to the Audit Committee and the Company's Audit Committee financial experts is incorporated by reference to the information under "Meetings and Committees of the Board of Directors – Audit Committee" in the Company's definitive Proxy Statement for the 2018 Annual Meeting.

The Company has adopted a code of conduct that applies to all of its directors, officers (including its principal executive officer, principal financial officer, and its principal accounting officer or controller or person performing similar functions) and employees. The Company's code of conduct is available on its website at www.ottertail.com. The Company intends to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of its code of conduct by posting such information on its website at the address specified above. Information on the Company's website is not deemed to be incorporated by reference into this Annual Report on Form 10-K.

Item 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information under "Compensation Discussion and Analysis," "Report of Compensation Committee," "Executive Compensation" and "Director Compensation" in the Company's definitive Proxy Statement for the 2018 Annual Meeting.

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Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item regarding security ownership is incorporated by reference to the information under "Security Ownership of Certain Beneficial Owners" and "Security Ownership of Directors and Officers" in the Company's definitive Proxy Statement for the 2018 Annual Meeting.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth information as of December 31, 2017 about the Company's common stock that may be issued under all of its equity compensation plans:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)

Equity compensation plans approved by security holders:				
2014 Stock Incentive Plan	411,585(1)	$	0.00	1,244,353(2)
1999 Stock Incentive Plan	2,325(3)	$	0.00	--(4)
1999 Employee Stock Purchase Plan	--		N/A	374,624(5)
Equity compensation plans not approved by security holders	--		--	--
Total	413,910	$	0.00	1,618,977

(1) Includes 85,500, 116,700 and 114,648 performance based share awards granted in 2017, 2016 and 2015, respectively, 94,190 restricted stock units outstanding as of December 31, 2017, and 547 stock units as part of the director deferred compensation program, and excludes 49,695 shares of restricted stock issued under the 2014 Stock Incentive Plan.

(2) The 2014 Stock Incentive Plan provides for the issuance of any shares available under the plan in the form of restricted stock, restricted stock units, performance awards and other types of stock-based awards, in addition to the granting of options, warrants or stock appreciation rights.

(3) Director deferred compensation program stock units under the 1999 Stock Incentive Plan.

(4) The 1999 Stock Incentive Plan provided for the issuance of any shares available under the plan in the form of restricted stock, restricted stock units, performance awards and other types of stock-based awards, in addition to the granting of options, warrants or stock appreciation rights. The 1999 Stock Incentive Plan expired by its terms on December 13, 2013 and no more awards may be granted thereunder.

(5) Shares are issued based on employee's election to participate in the plan.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the information under "Policy and Procedures Regarding Transactions with Related Persons," "Election of Directors" and "Meetings and Committees of the Board of Directors" in the Company's definitive Proxy Statement for the 2018 Annual Meeting.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the information under "Ratification of Independent Registered Public Accounting Firm – Fees" and "Ratification of Independent Registered Public Accounting Firm – Pre-Approval of Audit/Non-Audit Services Policy" in the Company's definitive Proxy Statement for the 2018 Annual Meeting.

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PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) List of documents filed as part of this report:

1. Financial Statements

	Page
Report of Independent Registered Public Accounting Firm	60
Consolidated Balance Sheets, December 31, 2017 and 2016	61
Consolidated Statements of Income for the Three Years Ended December 31, 2017	63
Consolidated Statements of Comprehensive Income for the Three Years Ended December 31, 2017	64
Consolidated Statements of Common Shareholders' Equity for the Three Years Ended December 31, 2017	65
Consolidated Statements of Cash Flows for the Three Years Ended December 31, 2017	66
Consolidated Statements of Capitalization, December 31, 2017 and 2016	67
Notes to Consolidated Financial Statements	68

2. Financial Statement Schedules

SCHEDULE 1 - CONDENSED FINANCIAL INFORMATION OF REGISTRANT
OTTER TAIL CORPORATION (PARENT COMPANY)
Condensed Balance Sheets, December 31

(in thousands)	**2017**	2016
ASSETS		
Current Assets		
Cash and Cash Equivalents	**$ 16,371**	$ 6,218
Accounts Receivable	**--**	12
Accounts Receivable from Subsidiaries	**2,098**	1,706
Interest Receivable from Subsidiaries	**117**	141
Income Taxes Receivable	**--**	662
Notes Receivable from Subsidiaries	**1,752**	1,671
Other	**1,130**	936
Total Current Assets	**21,468**	11,346
Investments in Subsidiaries	**724,613**	692,723
Notes Receivable from Subsidiaries	**79,611**	79,843
Deferred Income Taxes	**27,923**	35,387
Other Assets	**31,559**	29,079
Total Assets	**$ 885,174**	$ 848,378

LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	**$ --**	$ --
Current Maturities of Long-Term Debt	**186**	231
Accounts Payable to Subsidiaries	**6**	5,958
Notes Payable to Subsidiaries	**61,908**	38,519
Other	**7,799**	5,838
Total Current Liabilities	**69,899**	50,546
Other Noncurrent Liabilities	**38,319**	32,556
Commitments and Contingencies		
Capitalization		
Long-Term Debt, Net of Current Maturities	**80,064**	95,172
Common Shareholder Equity	**696,892**	670,104
Total Capitalization	**776,956**	765,276
Total Liabilities and Equity	**$ 885,174**	$ 848,378

See accompanying notes to condensed financial statements.

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OTTER TAIL CORPORATION (PARENT COMPANY)
Condensed Statements of Income--For the Years Ended December 31

(in thousands)	**2017**	2016	2015
Operating Loss			
Revenue	**$ --**	$ --	$ --
Operating Expenses	**8,353**	9,689	10,188
Operating Loss	**(8,353)**	(9,689)	(10,188)
Other Income (Expense)			
Equity Income in Earnings of Subsidiaries	**82,715**	67,047	66,067
Interest Charges	**(4,270)**	(6,817)	(6,786)
Interest Charges to Subsidiaries	**(244)**	(173)	(193)
Interest Income from Subsidiaries	**2,848**	4,897	4,786
Other Income	**1,054**	1,621	421
Total Other Income	**82,103**	66,575	64,295
Income Before Income Taxes	**73,750**	56,886	54,107
Income Tax Expense (Benefit)	**1,311**	(5,435)	(5,238)
Net Income	**$ 72,439**	$ 62,321	$ 59,345

See accompanying notes to condensed financial statements.

OTTER TAIL CORPORATION (PARENT COMPANY)
Condensed Statements of Cash Flows--For the Years Ended December 31

(in thousands)	**2017**	2016	2015
Cash Flows from Operating Activities			
Net Cash Provided by Operating Activities	**$ 50,205**	$ 83,296	$ 53,958
Cash Flows from Investing Activities			
Return of Capital (Investment in Subsidiaries)	**--**	9,912	(88,079)
Debt Repaid by (Issued to) Subsidiaries	**151**	(3,309)	(12,592)
Cash (Used in) Provided by Investing Activities	**(121)**	106	(11)
Net Cash Provided by (Used in) Investing Activities	**30**	6,709	(100,682)
Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	**--**	(428)	213
Net Short-Term (Repayments) Borrowings	**--**	(59,666)	48,812
Borrowings from (Repayments to) Subsidiaries	**23,389**	(60,948)	32,249
Proceeds from Issuance of Common Stock	**4,349**	44,435	14,233
Common Stock Issuance Expenses	**--**	(562)	(451)
Payments for Retirement of Capital Stock	**(1,799)**	(104)	(1,596)
Proceeds from the Issuance of Long-Term Debt	**--**	130,000	--
Short-Term and Long-Term Debt Issuance Expenses	**(158)**	(723)	(312)
Payments for Retirement of Long-Term Debt	**(15,231)**	(87,547)	(201)
Dividends Paid and Other Distributions	**(50,632)**	(48,244)	(46,223)
Net Cash (Used in) Provided by Financing Activities	**(40,082)**	(83,787)	46,724
Net Change in Cash and Cash Equivalents	**10,153**	6,218	--
Cash and Cash Equivalents at Beginning of Period	**6,218**	--	--
Cash and Cash Equivalents at End of Period	**$ 16,371**	$ 6,218	$ --

See accompanying notes to condensed financial statements.

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Incorporated by reference are Otter Tail Corporation's consolidated statements of comprehensive income and common shareholders' equity in Part II, Item 8.

Basis of Presentation

The condensed financial information of Otter Tail Corporation is presented to comply with Rule 12-04 of Regulation S-X. The unconsolidated condensed financial statements do not reflect all of the information and notes normally included with financial statements prepared in accordance with GAAP. Therefore, these condensed financial statements should be read with the consolidated financial statements and related notes included in this Annual Report on Form 10-K.

Otter Tail Corporation's investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income from operations of the subsidiaries is reported on a net basis as equity income in earnings of subsidiaries.

Related Party Transactions

As of December 31, 2017: *(in thousands)*	Accounts Receivable	Interest Receivable	Current Notes Receivable	Long-Term Notes Receivable	Accounts Payable	Current Notes Payable
Otter Tail Power Company	$ 2,067	$ --	$ --	$ --	$ 6	$ --
Vinyltech Corporation	2	17	--	11,500	--	20,603
Northern Pipe Products, Inc.	4	8	--	5,711	--	8,186
BTD Manufacturing, Inc.	--	77	--	52,000	--	7,260
Wind Tower Business	--	--	1,461	--	--	--
Dock and Boatlift Business	--	--	291	--	--	--
T.O. Plastics, Inc.	--	15	--	10,400	--	13,446
Varistar Corporation	--	--	--	--	--	12,413
Otter Tail Assurance Limited	25	--	--	--	--	--
	$ 2,098	$ 117	$ 1,752	$ 79,611	$ 6	$ 61,908

As of December 31, 2016: *(in thousands)*	Accounts Receivable	Interest Receivable	Current Notes Receivable	Long-Term Notes Receivable	Accounts Payable	Current Notes Payable
Otter Tail Power Company	$ 1,572	$ --	$ --	$ --	$ 10	$ --
Vinyltech Corporation	3	20	--	11,500	--	15,951
Northern Pipe Products, Inc.	--	10	--	5,943	--	6,560
BTD Manufacturing, Inc.	--	92	--	52,000	--	2,342
Wind Tower Business	--	--	1,441	--	--	--
Dock and Boatlift Business	--	--	230	--	--	--
T.O. Plastics, Inc.	--	19	--	10,400	--	12,378
Varistar Corporation	60	--	--	--	5,948	1,288
Otter Tail Assurance Limited	71	--	--	--	--	--
	$ 1,706	$ 141	$ 1,671	$ 79,843	$ 5,958	$ 38,519

Dividends

Dividends paid to Otter Tail Corporation (the Parent) from its subsidiaries were as follows:

(in thousands)	2017	2016	2015
Cash Dividends Paid to Parent by Subsidiaries	$ 50,571	$ 77,779	$ 46,188

See Otter Tail Corporation's notes to consolidated financial statements in Part II, Item 8 for other disclosures.

Other schedules are omitted because of the absence of the conditions under which they are required, because the amounts are insignificant or because the information required is included in the financial statements or the notes thereto.

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3. *Exhibits*
The following Exhibits are filed as part of, or incorporated by reference into, this report.

	Previously Filed		
	File No.	**As Exhibit No.**	
2-A	8-K filed 7/1/09	2.1	—Plan of Merger, dated as of June 30, 2009, by and among Otter Tail Corporation (now known as Otter Tail Power Company), Otter Tail Holding Company (now known as Otter Tail Corporation) and Otter Tail Merger Sub Inc.
2-B	10-K/A for year ended 12/31/16	2-B	—Asset Purchase Agreement, dated as of November 16, 2016, among Otter Tail Power Company, EDF Renewable Development, Inc., Power Partners Midwest, LLC, EDF-RE US Development, LLC and Merricourt Power Partners, LLC.**/***
2-C	10-K/A for year ended 12/31/16	2-C	—Turnkey Engineering, Procurement and Construction Services Agreement, dated as of November 16, 2016, between Otter Tail Power Company and EDF-RE US Development, LLC.**/***
3-A	8-K filed 7/1/09	3.1	—Restated Articles of Incorporation.
3-B	8-K filed 7/1/09	3.2	—Restated Bylaws.

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4-A	8-K filed 8/23/07	4.1	—Note Purchase Agreement, dated as of August 20, 2007.
4-A-1	8-K filed 12/20/07	4.3	—First Amendment, dated as of December 14, 2007, to Note Purchase Agreement, dated as of August 20, 2007.
4-A-2	8-K filed 9/15/08	4.1	—Second Amendment, dated as of September 11, 2008, to Note Purchase Agreement, dated as of August 20, 2007.
4-A-3	8-K filed 7/1/09	4.2	—Third Amendment, dated as of June 26, 2009, to Note Purchase Agreement dated as of August 20, 2007.
4-B	8-K filed 11/2/12	4.1	—Third Amended and Restated Credit Agreement dated as of October 29, 2012 among Otter Tail Corporation, the Banks named therein, Bank of America, N.A. and JPMorgan Chase Bank, N.A., as Co-Syndication Agents, KeyBank National Association, as Documentation Agent, U.S. Bank National Association, as administration agent for the Banks and U.S. Bank National Association, Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC, as Joint Lead Arrangers and Joint Book Runners.
4-B-1	8-K filed 11/1/13	4.1	—First Amendment to Third Amended and Restated Credit Agreement, dated as of October 29, 2013, among Otter Tail Corporation, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, and Bank of the West and Union Bank, N.A., as Banks.
4-B-2	8-K filed 11/4/14	4.1	—Second Amendment to Third Amended and Restated Credit Agreement, dated as of November 3, 2014, among Otter Tail Corporation, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, and Bank of the West as a Bank.
4-B-3	8-K filed 11/3/15	4.1	—Third Amendment to Third Amended and Restated Credit Agreement, dated as of October 29, 2015, among Otter Tail Corporation, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, and Bank of the West as a Bank.

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	Previously Filed		
	File No.	As Exhibit No.	
4-B-4	8-K filed 11/3/16	4.1	—Fourth Amendment to Third Amended and Restated Credit Agreement, dated as of October 31, 2016, among Otter Tail Corporation, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, and Bank of the West as a Bank.
4-B-5	8-K filed 11/2/17	4.1	—Fifth Amendment to Third Amended and Restated Credit Agreement, dated as of October 31, 2017, among Otter Tail Corporation, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, and Bank of the West as a Bank.
4-C	8-K filed 11/2/12	4.2	—Second Amended and Restated Credit Agreement dated as of October 29, 2012 among Otter Tail Power Company, the Banks named therein, JPMorgan Chase Bank, N.A. and Bank of America, N.A., as Co-Syndication Agents, KeyBank National Association and CoBank, ACB, as Co-Documentation Agents, U.S. Bank National Association, as administrative agent for the Banks, and U.S. Bank National Association, Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC, as Joint Lead Arrangers and Joint Book Runners.
4-C-1	8-K filed 11/1/13	4.2	— First Amendment to Second Amended and Restated Credit Agreement, dated as of October 29, 2013, among Otter Tail Power Company, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, CoBank, ACB, as a Co-Documentation Agent and as a Bank, and Wells Fargo Bank, National Association and Union Bank, N.A., as Banks.
4-C-2	8-K filed 11/4/14	4.2	— Second Amendment to Second Amended and Restated Credit Agreement, dated as of November 3, 2014, among Otter Tail Power Company, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, CoBank, ACB, as a Co-Documentation Agent and as a Bank, and Wells Fargo Bank, National Association as a Bank.
4-C-3	8-K filed 11/3/15	4.2	— Third Amendment to Second Amended and Restated Credit Agreement, dated as of October 29, 2015, among Otter Tail Power Company, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, CoBank, ACB, as a Co-Documentation Agent and as a Bank, and Wells Fargo Bank, National Association as a Bank.
4-C-4	8-K filed 11/3/16	4.2	— Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of October 31, 2016, among Otter Tail Power Company, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, CoBank, ACB, as a Co-Documentation Agent and as a Bank, and Wells Fargo Bank, National Association as a Bank.

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	Previously Filed		
	File No.	As Exhibit No.	
4-C-5	8-K filed 11/2/17	4.2	— Fifth Amendment to Second Amended and Restated Credit Agreement, dated as of October 31, 2017, among Otter Tail Power Company, U.S. Bank National Association, as Administrative Agent and as a Bank, Bank of America, N.A. and JPMorgan Chase Bank, N.A., each as a Co-Syndication Agent and as a Bank, KeyBank National Association, as Documentation Agent and as a Bank, CoBank, ACB, as a Co-Documentation Agent and as a Bank, and Wells Fargo Bank, National Association as a Bank.

4-D	8-K filed 8/3/11	4.1	—Note Purchase Agreement, dated as of July 29, 2011, between Otter Tail Power Company and the Purchasers named therein.
4-E	8-K filed 8/16/13	4.1	—Note Purchase Agreement dated as of August 14, 2013 between Otter Tail Power Company and the Purchasers named therein.
4-F	8-K filed 2/9/16	4.1	—Term Loan Agreement dated as of February 5, 2016 among Otter Tail Corporation, the Banks named therein and JPMorgan Chase Bank, N.A., as administrative agent for the Banks, and J.P. Morgan Securities LLC, as Lead Arranger and Book Runner.
4-G	8-K filed 9/27/16	4.1	—Note Purchase Agreement dated as of September 23, 2016 between Otter Tail Corporation and the Purchasers named therein.
4-H	8-K filed 11/16/17	4.1	—Note Purchase Agreement dated as of November 14, 2017 between Otter Tail Power Company and the Purchasers named therein.
10-A	10-K for year ended 12/31/89	10-F	—Agreement for Sharing Ownership of Generating Plant by and between the Company, Montana-Dakota Utilities Co., and Northwestern Public Service Company (dated as of January 7, 1970).
10-A-1	10-K for year ended 12/31/89	10-F-1	—Letter of Intent for purchase of share of Big Stone Plant from Northwestern Public Service Company (dated as of May 8, 1984).
10-A-2	10-K for year ended 12/31/91	10-F-2	—Supplemental Agreement No. 1 to Agreement for Sharing Ownership of Big Stone Plant (dated as of July 1, 1983).
10-A-3	10-K for year ended 12/31/91	10-F-3	—Supplemental Agreement No. 2 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 1, 1985).
10-A-4	10-K for year ended 12/31/91	10-F-4	—Supplemental Agreement No. 3 to Agreement for Sharing Ownership of Big Stone Plant (dated as of March 31, 1986).
10-A-5	10-Q for quarter ended 9/30/03	10.1	—Supplemental Agreement No. 4 to Agreement for Sharing Ownership of Big Stone Plant (dated as of April 24, 2003).
10-A-6	10-K for year ended 12/31/92	10-F-5	—Amendment I to Letter of Intent dated May 8, 1984, for purchase of share of Big Stone Plant.
10-B	10-Q for quarter ended 6/30/15	10.3	—Big Stone South–Ellendale Project Ownership Agreement dated as of June 12, 2015 between Otter Tail Power Company, a wholly owned subsidiary of Otter Tail Corporation, and Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc.**
10-C	2-61043	5-H	—Agreement for Sharing Ownership of Coyote Station Generating Unit No. 1 by and between the Company, Minnkota Power Cooperative, Inc., Montana-Dakota Utilities Co., Northwestern Public Service Company and Minnesota Power & Light Company (dated as of July 1, 1977).
10-C-1	10-K for year ended 12/31/89	10-H-1	—Supplemental Agreement No. One, dated as of November 30, 1978, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-C-2	10-K for year ended 12/31/89	10-H-2	—Supplemental Agreement No. Two, dated as of March 1, 1981, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1 and Amendment No. 2 dated March 1, 1981, to Coyote Plant Coal Agreement.

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	Previously Filed		
	File No.	As Exhibit No.	
10-C-3	10-K for year ended 12/31/89	10-H-3	—Amendment, dated as of July 29, 1983, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-C-4	10-K for year ended 12/31/92	10-H-4	—Agreement, dated as of September 5, 1985, containing Amendment No. 3 to Agreement for Sharing Ownership of Coyote Generating Unit No. 1, dated as of July 1, 1977, and Amendment No. 5 to Coyote Plant Coal Agreement, dated as of January 1, 1978.
10-C-5	10-Q for quarter ended 9/30/01	10-A	—Amendment, dated as of June 14, 2001, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-C-6	10-Q for quarter ended 9/30/03	10.2	—Amendment, dated as of April 24, 2003, to Agreement for Sharing Ownership of Coyote Generating Unit No. 1.
10-D	10-K for year ended 12/31/12	10-J	—Lignite Sales Agreement between Coyote Creek Mining Company, L.L.C. and Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., Northwestern Corporation, dated as of October 10, 2012.**
10-D-1	8-K filed 1/31/14	10.1	—First Amendment to Lignite Sales Agreement dated as of January 30, 2014 among Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., NorthWestern Corporation and Coyote Creek Mining Company, L.L.C.
10-D-2	8-K filed 3/18/15	10.1	—Second Amendment to Lignite Sales Agreement dated as of March 16, 2015 among Otter Tail Power Company, Northern Municipal Power Agency, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., NorthWestern Corporation and Coyote Creek Mining Company, L.L.C.
10-E	10-Q/A for quarter ended 6/30/13	10.1	—Wind Energy Purchase Agreement dated May 9, 2013 between Otter Tail Power Company and Ashtabula Wind III, LLC.**
10-F-1	10-K for year ended 12/31/02	10-N-1	—Deferred Compensation Plan for Directors, as amended.*
10-F-1a	10-K for year ended 12/31/10	10-N-1A	—First Amendment of Deferred Compensation Plan for Directors (2003 Restatement), as amended.*
10-F-1b	8-K filed 4/17/14	10.5	—Second Amendment of Deferred Compensation Plan for Directors (2003 Restatement), as amended.*
10-F-2	8-K filed 2/04/05	10.1	—Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-F-2a	10-K for year ended 12/31/06	10-N-2a	—First Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-F-2b	10-K for year ended 12/31/10	10-N-2B	—Second Amendment of Executive Survivor and Supplemental Retirement Plan (2005 Restatement).*
10-F-3	10-Q for quarter ended 9/30/11	10.1	—Nonqualified Retirement Plan (2011 Restatement).*
10-F-4	10-Q for quarter ended 9/30/16	10.1	—1999 Employee Stock Purchase Plan, As Amended (2016).
10-F-5	8-K filed 4/13/06	10.4	—1999 Stock Incentive Plan, As Amended (2006).*
10-F-6	8-K filed 4/13/06	10.1	—Form of Restricted Stock Award Agreement for Directors.*
10-F-7	10-K for year ended	10-O-12	—2014 Executive Annual Incentive Plan.*

	12/31/13		
10-F-8	333-195337	4.1	—Otter Tail Corporation 2014 Stock Incentive Plan.*
10-F-9	8-K filed 4/17/14	10.1	—Form of 2014 Performance Award Agreement.*

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	Previously Filed		
	File No.	As Exhibit No.	
10-F-10	8-K filed 4/17/14	10.2	—Form of 2014 Restricted Stock Award Agreement for Executive Officers.*
10-F-11	8-K filed 4/17/14	10.3	—Form of 2014 Restricted Stock Award Agreement for Directors.*
10-F-12	10-K for year ended 12/31/16	10-J-14	—Summary of Non-Employee Director Compensation (2016).*
10-F-13	8-K filed 2/11/15	10.1	—Form of 2015 Performance Award Agreement (Executives).*
10-F-14	8-K filed 2/11/15	10.2	—Form of 2015 Performance Award Agreement (Legacy).*
10-F-15	8-K filed 2/11/15	10.3	—Form of 2015 Restricted Stock Unit Award Agreement (Executives).*
10-F-16	8-K filed 2/11/15	10.4	—Form of 2015 Restricted Stock Unit Award Agreement (Legacy).*
10-F-17	8-K filed 4/15/15	10.2	—Form of 2015 Restricted Stock Award Agreement for Directors.*
10-F-18	8-K filed 2/11/15	10.5	—Otter Tail Corporation Executive Restoration Plus Plan, as Amended and Restated.*
10-F-18a			—First Amendment of Otter Tail Corporation Executive Restoration Plus Plan*
10-F-19			—Summary of Non-Employee Director Compensation (2018).*
10-G	8-K filed 5/11/15	1.1	—Distribution Agreement dated May 11, 2015, between Otter Tail Corporation and J.P. Morgan Securities LLC.
10-H-1	10-K for year ended 12/31/12	10-O-1	—Executive Employment Agreement, Kevin Moug.*
10-H-2	10-K for year ended 12/31/12	10-O-2	—Executive Employment Agreement, George Koeck.*
10-I-1	10-K for year ended 12/31/10	10-Q-3	—Change in Control Severance Agreement, Kevin G. Moug.*
10-I-2	10-K for year ended 12/31/10	10-Q-4	—Change in Control Severance Agreement, George Koeck.*
10-I-3	10-K for year ended 12/31/11	10-Q-5	—Change in Control Severance Agreement, Chuck MacFarlane.*
10-I-4	10-Q for quarter ended 9/30/14	10.3	—Change in Control Severance Agreement, Timothy Rogelstad.*
10-I-5	10-Q for quarter ended 9/30/14	10.6	—Change in Control Severance Agreement, Paul Knutson.*
10-I-6	10-K for year ended 12/31/15	10-R-6	—Change in Control Severance Agreement, John Abbott.*
10-I-7			—Change in Control Severance Agreement, Jennifer Smestad.*
10-J			—Otter Tail Corporation Executive Severance Plan.*
12.1			—Calculation of Ratios of Earnings to Fixed Charges and Preferred Dividends.
21-A			—Subsidiaries of Registrant.
23-A			—Consent of Deloitte & Touche LLP.
24-A			—Power of Attorney.
31.1			—Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2			—Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1			—Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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	Previously Filed		
	File No.	As Exhibit No.	
32.2			—Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101			—Financial statements from the Annual Report on Form 10-K of Otter Tail Corporation for the year ended December 31, 2017, formatted in Extensible Business Reporting Language: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Income, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Common Shareholders' Equity, (v) the Consolidated Statements of Cash Flows, (vi) the Consolidated Statements of Capitalization, (vii) the Notes to Consolidated Financial Statements and (viii) Schedule I.

*Management contract, compensatory plan or arrangement required to be filed pursuant to Item 601(b)(10)(iii)(A) of Regulation S-K.

**Confidential information has been omitted from this Exhibit and filed separately with the Securities and Exchange Commission pursuant to a confidential treatment request under Rule 24b-2.

***Schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The Company hereby undertakes to furnish copies of any of the omitted schedules and exhibits to the Securities and Exchange Commission upon request.

Pursuant to Item 601(b)(4)(iii) of Regulation S-K, copies of certain instruments defining the rights of holders of certain long-term debt of the Company are not filed, and in lieu thereof, the Company agrees to furnish copies thereof to the Securities and Exchange Commission upon request.

Item 16. FORM 10-K SUMMARY

None.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

OTTER TAIL CORPORATION

By /s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer and Senior Vice President
(authorized officer and principal financial officer)

Dated: February 20, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

Signature and Title

Charles S. MacFarlane
President and Chief Executive Officer
(principal executive officer) and Director

Kevin G. Moug
Chief Financial Officer and Senior Vice President
(principal financial and accounting officer)

Nathan I. Partain
Chairman of the Board and Director

Karen M. Bohn, Director

John D. Erickson, Director

Steven L. Fritze, Director

Kathryn O. Johnson, Director

Timothy J. O'Keefe, Director

Joyce Nelson Schuette, Director

James B. Stake, Director

By /s/ Charles S. MacFarlane
Charles S. MacFarlane
Pro Se and Attorney-in-Fact
Dated February 20, 2018

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Section 2: EX-10.F18A (EXHIBIT 10.F-18A)

Exhibit 10-F-18a

FIRST AMENDMENT
OF
OTTER TAIL CORPORATION
EXECUTIVE RESTORATION PLUS PLAN

WHEREAS, Otter Tail Corporation (the "Company") maintains an unfunded deferred compensation plan (the "Plan") for the benefit of a select group of management and highly compensated employees of the Company, which was originally effective July 1, 2012, and most recently amended and restated effective February 6, 2015, in a document entitled "OTTER TAIL CORPORATION EXECUTIVE RESTORATION PLUS PLAN" (hereinafter referred to as the "Plan Document"); and

WHEREAS, The Company has the authority to make amendments to the Plan Document;

NOW, THEREFORE, The Plan Document is hereby amended to read as follows:

1. DEFINITION OF AFFILIATE. Effective January 1, 2018, Section 2 of the Plan Document is amended by the addition of the following new Section 2.2 and all subsequent sections (and cross references thereto) shall be renumbered accordingly:

2.2. Affiliate. "Affiliate" means a business entity which is under "common control" with the Company or which is a member of an "affiliated service group" that includes the Company, as those terms are defined in Code sections 414(b), (c) and (m).

2. DEFINTION OF EMPLOYER. Effective January 1, 2018, the definition of Employer in Section 2.12 (which will be renumbered as Section 2.13) of the Plan Document is amended to read in full as follows:

2.13. Employer. “Employer” means the Company or any Affiliates that have been selected by the Board to participate in the Plan.

3. ELIBILITY AND PARTICIPATION. Effective January 1, 2018, the first sentence of Section 3.1 of the Plan Document is amended to read in full as follows:

Any executive officer or employee of the Employer who is named by the Committee is eligible to participate in the Plan.

4. SAVINGS CLAUSE. Save and except as hereinabove expressly amended, the Plan Document shall continue in full force and effect.

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Section 3: EX-10.F19 (EXHIBIT 10.F-19)

Exhibit 10-F-19

SUMMARY OF NON-EMPLOYEE DIRECTOR COMPENSATION (April 2018)

Compensation: Non-employee directors shall receive the following remuneration:

Director’s Retainer (except Chairman)	$	60,000
Chairman of the Board Retainer	$	125,000
Compensation and Corporate Governance Committee Chair Retainer	$	14,000
Audit Committee Chair Retainer	$	20,000
Restricted Stock Award Value (except Chairman)	$	80,000
Restricted Stock Award Value (Chairman of the Board)	$	105,000
Restricted Stock Award Value (additional per Committee)	$	10,000

Directors may elect to receive their retainer (other than expense reimbursements) in the form of cash, stock or a combination. Directors may elect to defer the receipt of all or part of their cash compensation pursuant to the Deferred Compensation Plan for Directors. The deferral may be in the form of cash or stock units. Cash deferrals receive interest at a rate equal to 1% over the prime commercial rate of U.S. Bank National Association. Deferrals in the form of stock units are credited quarterly with dividend equivalents equal to the dividend rate on Otter Tail Corporation’s common shares and the deferred amount is paid out in common shares.
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Section 4: EX-10.I7 (EXHIBIT 10.I-7)

Exhibit 10-I-7

CHANGE IN CONTROL
SEVERANCE AGREEMENT

This Change in Control Severance Agreement (the “Agreement”) is made as of the 1st day of January, 2018, between Otter Tail Corporation, a Minnesota corporation, with its principal offices at 215 South Cascade Street, P.O. Box 496, Fergus Falls, Minnesota 56538-0496 (the "Corporation ") and Jennifer O. Smestad ("You"), residing at 17746 Co. Highway 29, Fergus Falls, MN 56537, and supersedes any prior Change in Control Agreement between the Corporation and You.

WITNESSETH THAT:

WHEREAS, this Agreement is intended to specify the financial arrangements that the Corporation will provide to You upon Your separation from employment with the Corporation under any of the circumstances described herein; and

WHEREAS, this Agreement is entered into by the Corporation in the belief that it is in the best interests of the Corporation and its shareholders to provide stable conditions of employment for You notwithstanding the possibility, threat or occurrence of certain types of change in control, thereby enhancing the Corporation's ability to attract and retain highly qualified people; and

NOW, THEREFORE, to assure the Corporation that it will have Your continued dedication notwithstanding the possibility, threat or occurrence of a bid to take over control of the Corporation, and to induce You to remain in the employ of the Corporation, and for other good and valuable consideration, the Corporation and You agree as follows:

1. . Termination of Employment.

(i) Prior to a Change in Control. Your rights upon termination of employment prior to a Change in Control (as defined in Section 2(i) hereof) shall be governed by the Corporation's standard employment termination policy applicable to You in effect at the time of termination or Your Severance Agreement.

(ii) After a Change in Control.

(a) From and after the date of a Change in Control during the term of this Agreement, the Corporation shall not terminate You from employment with the Corporation except as provided in this Section 1(ii) or as a result of Your Disability (as defined in Section 2(iv) hereof) or death.

(b) From and after the date of a Change in Control during the term of this Agreement, the Corporation shall have the right to terminate You from employment with the Corporation at any time during the term of this Agreement for Cause (as defined in Section 2(iii) hereof), by written notice to You, specifying the particulars of Your conduct forming the basis for such termination.

(c) From and after the date of a Change in Control during the term of this Agreement: (i) the Corporation shall have the right to terminate Your employment without Cause at any time; and (ii You shall, upon the occurrence of such a termination by the Corporation without Cause, or upon the voluntary termination of employment by You for Good Reason (as defined in Section 2(ii) hereof), be entitled to receive the benefits provided in Section 3 hereof. You shall evidence a voluntary termination for Good Reason by written notice to the Corporation given within ninety (90) days after the date of the occurrence of any event that You know or should reasonably have known constitutes Good Reason for voluntary termination and the Corporation has thirty (30) days from the date the Corporation receives the notice from You to remedy the condition. Such notice need only identify You and set forth in reasonable detail the facts and circumstances claimed by You to constitute Good Reason.

Any notice given by You pursuant to this Section 1 shall be effective five (5) business days after the date it is given by You.

2. Definitions.

(i) A "Change in Control" shall mean:

(a) a change in control of a nature that would be required to be reported in response to Item 6(e) of Schedule 14A of Regulation 14A promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or successor provision thereto, whether or not the Corporation is then subject to such reporting requirement;

(b) any "person" (as such term is used in Sections 13(d) and 14(d) of the Exchange Act) is or becomes the "beneficial owner" (as defined in Rule 13d-3 promulgated under the Exchange Act), directly or indirectly, of securities of the Corporation representing 35% or more of the combined voting power of the Corporation's then outstanding securities;

(c) the Continuing Directors (as defined in Section 2(v) hereof) cease to constitute a majority of the Corporation's Board of Directors; provided that such change is the direct or indirect result of a proxy fight and contested election or elections for positions on the Board of Directors; or

(d) the majority of the Continuing Directors (as defined in Section 2(v) hereof) determine in their sole and absolute discretion that there has been a change in control of the Corporation.

(ii) "Good Reason" shall mean the occurrence of any of the following events that results in a material negative change to You, except for the occurrence of such an event in connection with the termination or reassignment of You by the Corporation for Cause, for Disability or for death:

(a) the assignment to You of employment responsibilities which are not of comparable responsibility and status as the employment responsibilities held by You immediately prior to a Change in Control;

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(b) a reduction by the Corporation in Your base salary as in effect immediately prior to a Change in Control;

(c) an amendment or modification of the Corporation's incentive compensation program (except as may be required by applicable law) which affects the terms or administration of the program in a manner adverse to Your interest as compared to the terms and administration of such program immediately prior to a Change in Control;

(d) the Corporation's requiring You to be based anywhere other than within 50 miles of Your office location immediately prior to a Change in Control, except for requirements of temporary travel on the Corporation's business to an extent substantially consistent with Your business travel obligations immediately prior to a Change in Control;

(e) except to the extent otherwise required by applicable law, the failure by the Corporation to continue in effect any benefit or compensation plan, stock ownership plan, stock purchase plan, stock incentive plan, bonus plan, life insurance plan, health-and-accident plan, or disability plan in which You are participating immediately prior to a Change in Control (or plans providing You with substantially similar benefits), the taking of any action by the Corporation which would adversely affect Your participation in, or materially reduce Your benefits under, any of such plans or deprive You of any material fringe benefit enjoyed by You immediately prior to such Change in Control, or the failure by the Corporation to provide You with the number of paid vacation days to which You are entitled immediately prior to such Change in Control in accordance with the Corporation's vacation policy as then in effect; or

(f) the failure by the Corporation to obtain, as specified in Section 5(i) hereof, an assumption of the obligations of the Corporation to perform this Agreement by any successor to the Corporation.

(iii) "Cause" shall mean termination by the Corporation of Your employment based upon (a) the willful and continued failure by You substantially to perform Your duties and obligations (other than any such failure resulting from Your incapacity due to physical or mental illness or any such actual or anticipated failure resulting from Your termination for Good Reason) or (b) the willful engaging by You in misconduct which is materially injurious to the Corporation, monetarily or otherwise. For purposes of this Section 2(iii), no action or failure to act on Your part shall be considered "willful" unless done, or omitted to be done, by You in bad faith and without reasonable belief that such action or omission was in the best interests of the Corporation.

(iv) "Disability" shall mean any physical or mental condition which would qualify You for a disability benefit under the Corporation's long-term disability plan.

(v) "Continuing Director" shall mean any person who is a member of the Board of Directors of the Corporation, while such person is a member of the Board of Directors, who is not an Acquiring Person (as hereinafter defined) or an Affiliate or Associate (as hereinafter defined) of an Acquiring Person, or a representative of an Acquiring Person or of any such Affiliate or Associate, and who (a) was a member of the Board of Directors on the date of this Agreement as first written above or (b) subsequently becomes a member of the Board of Directors, if such person's nomination for election or initial election to the Board of Directors is recommended or approved by a majority of the Continuing Directors. For purposes of this Section 2(v): "Acquiring Person" shall mean any "person" (as such term is used in Sections 13(d) and 14(d) of the Exchange Act) who or which, together with all Affiliates and Associates of such person, is the "beneficial owner" (as defined in Rule 13d-3 promulgated under the Exchange Act) of 20% or more of the shares of Common Stock of the Corporation then outstanding, but shall not include the Corporation, any subsidiary of the Corporation or any employee benefit plan of the Corporation or of any subsidiary of the Corporation or any entity holding shares of Common Stock organized, appointed or established for, or pursuant to the terms of, any such plan; and "Affiliate" and "Associate" shall have the respective meanings ascribed to such terms in Rule 12b-2 promulgated under the Exchange Act.

3. Benefits upon Termination under Section 1(ii)(c).

(i) Upon the termination (voluntary or involuntary) of Your employment pursuant to Section 1(ii)(c) hereof, You shall be entitled to receive the benefits specified in this Section 3. The amounts due to You under subparagraph (a) of this Section 3(i) shall be paid to You in a lump sum not later than one business day prior to the date that the termination of Your employment becomes effective. The amounts due to You under subparagraphs (b), (c) and (d) of this Section 3(i) shall be paid to You not later than one business day prior to the date that the termination of Your employment becomes effective. Subject to the provisions of Section 3(ii) hereof, all benefits to You pursuant to this Section 3(i) shall be subject to any applicable payroll or other taxes required by law to be withheld;

(a) The Corporation shall pay as severance pay to You an amount equal to one and a half (1½) times the sum of (1) Your highest annual rate of salary from the Corporation in effect at any time during the 24 months preceding the date that the termination of Your employment became effective and (2) the average of the annual bonus paid or to be paid to You in respect of each of the two fiscal years preceding the fiscal year when the termination of Your employment became effective;

(b) For a period of 24 months following the date that the termination of Your employment became effective or until You reach age 65 or die, whichever is the shorter period, the Corporation shall continue for You, at the Corporation's expense, the health, disability and life insurance coverage in effect for You immediately prior to the date that the termination of Your employment became effective under the plans provided by the Corporation for its executive personnel generally or, if such coverage cannot by the terms of such plans be provided thereunder, then the Corporation shall provide equivalent insurance coverage for You for such period under specially obtained policies of insurance;

(c) The Corporation shall pay to You (1) any amount earned by You as a bonus with respect to the fiscal year of the Corporation preceding the termination of Your employment if such bonus has not theretofore been paid to You, and (2) an amount representing credit for any vacation earned or accrued by You but not taken;

(d) The Corporation shall also pay to You all legal fees and expenses incurred by You as a result of such termination of employment (including all fees and expenses, if any, incurred by You in seeking to obtain or enforce any right or benefit provided to You by this Agreement whether by arbitration or otherwise);

(e) Any and all contracts, agreements or arrangements between the Corporation and You prohibiting or restricting You from owning, operating, participating in, or providing employment or consulting services to, any business or company competitive with the Corporation at any time or during any period after the date the termination of Your employment becomes effective, shall be deemed terminated and of no further force or effect as of the date the termination of Your employment becomes effective, to the extent, but only to the extent, such contracts, agreements or arrangements so prohibit or restrict You; provided that the foregoing provision shall not constitute a license or right to use any proprietary information of the Corporation and shall in no way affect any such contracts, agreements or arrangements insofar as they relate to nondisclosure and nonuse of proprietary information of the Corporation notwithstanding the fact that such nondisclosure and nonuse may prohibit or restrict You in certain competitive activities;

(f) Notwithstanding the foregoing, to the extent that any payment due hereunder is (A) deferred compensation subject to section 409A of the Internal Revenue Code, and (B) is payable to a specified employee (as that term is defined in section 409A), and (C) is payable on account of the specified employee's separation from service as that term is defined in section 409A), payment of any part of such amount that would have been made during the six (6) months following the separation from service shall not then be paid but shall rather be paid on the first day of the seventh (7^{th}) month following the separation from service.

(A) For this purpose, specified employees shall be identified by the Employer on a basis consistent with regulations issued under section 409A, and consistently applied to all plans, programs, contracts, etc. maintained by the Employer that are subject to section 409A.
(B) For this purpose separation from service shall be defined as it is defined in the regulations under section 409A.
(C) To the extent that 409A is applicable to this Agreement, this Agreement shall be construed and administered to comply with the rules of section 409A. Neither the Employer nor any of its officers, directors, agents or affiliates shall be obligated, directly or indirectly, to any Participant or any other person for any taxes, penalties, interest or like amounts that may be imposed on the Participant or other person on account of any amounts under this Plan or on account of any failure to comply with any Code section.

(ii) Any payment not made to You when due hereunder shall thereafter, until paid in full, bear interest at the rate of interest equal to the reference rate announced from time to time by U.S. Bank National Association, plus two percent, with such interest to be paid to You upon demand or monthly in the absence of a demand.

(iii) You shall not be required to mitigate the amount of any payment provided for in this Section 3 by seeking other employment or otherwise. The amount of any payment or benefit provided in this Section 3 shall not be reduced by any compensation earned by You as a result of any employment by another employer.

4. Your Agreements.

You agree that:

(i) Without the consent of the Corporation, You will not terminate employment with the Corporation without giving 60 days prior notice to the Corporation, and during such sixty (60) day period You will assist the Corporation, as and to the extent reasonably requested by the Corporation, in training the successor to Your position with the Corporation. The provisions of this Section 4(i) shall not apply to any termination (voluntary or involuntary) of Your employment pursuant to Section 1(ii)(c) hereof.

(ii) Without the consent of the Corporation or except as may be required by law, You will not at any time after termination of Your employment with the Corporation disclose to any person, corporation, firm, or other entity, confidential information concerning the Corporation of which You have gained knowledge during employment with the Corporation.

(iii) In the event that You have received any benefits from the Corporation under Section 3 of this Agreement, then, during the period of 24 months following the date that the termination of Your employment became effective, You, upon request by the Corporation:

(a) Will consult with one or more of the executive officers concerning the business and affairs of the Corporation for not to exceed four hours in any month at times and places selected by You, all without compensation other than what is provided for in Section 3 of this Agreement; and

(b) Will testify as a witness on behalf of the Corporation in any legal proceedings involving the Corporation which arise out of events or circumstances that occurred or existed prior to the date that the termination of Your employment became effective (except for any such proceedings relating to this Agreement), without compensation other than what is provided for in Section 3 of this Agreement, provided that all out-of-pocket expenses incurred by You in connection with serving as a witness shall be paid by the Corporation.

You shall not be required to perform Your obligations under this Section 4(iii) if and so long as the Corporation is in default with respect to performance of any of its obligations under this Agreement.

5. Successors and Binding Agreement.

(i) The Corporation will require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise to all or substantially all of the business and/or assets of the Corporation), by agreement in form and substance satisfactory to You, to expressly assume and agree to perform this Agreement in the same manner and to the same extent that the Corporation would be required to perform it if no such succession had taken place. Failure of the Corporation to obtain such agreement prior to the effectiveness of any such succession shall be a breach of this Agreement and shall entitle You to compensation from the Corporation in the same amount and on the same terms as You would be entitled hereunder if employee terminated employment after a Change in Control for Good Reason, except that for purposes of implementing the foregoing, the date on which any such succession becomes effective shall be deemed the date that the termination of Your employment becomes effective. As used in this Agreement, "Corporation" shall mean the Corporation and any successor to its business and/or assets which executes and delivers the agreement provided for in this Section 5(i) or which otherwise becomes bound by all the terms and provisions of this Agreement by operation of law.

(ii) This Agreement is personal to You, and You may not assign or transfer any part of Your rights or duties hereunder, or any compensation due to You hereunder, to any other person. Notwithstanding the foregoing, this Agreement shall inure to the benefit of and be enforceable by Your personal or legal representatives, executors, administrators, heirs, distributees, devisees, and legatees.

6. Arbitration. Any dispute or controversy arising under or in connection with this Agreement shall be settled exclusively by arbitration in Fergus Falls, Minnesota, in accordance with the applicable rules of the American Arbitration Association then in effect. Judgment may be entered on the arbitrator's award in any court having jurisdiction.

7. Modification; Waiver. No provisions of this Agreement may be modified, waived, or discharged unless such waiver, modification, or discharge is agreed to in a writing signed by You and such officer as may be designated by the Board of Directors of the Corporation. No waiver by either party hereto at any time of any breach by the other party hereto of, or compliance with, any condition or provision of this Agreement to be performed by such other party shall be deemed a waiver of similar or dissimilar provisions or conditions at the same or at any prior or subsequent time.

8. Notice. All notices, requests, demands, and all other communications required or permitted by either party to the other party by this Agreement (including, without limitation, any notice of termination of employment and any notice of an intention to arbitrate) shall be in writing and shall be deemed to have been duly given when delivered personally or received by certified or registered mail, return receipt requested, postage prepaid, at the address of the other party, as first written above (directed to the attention of the Board of Directors and Corporate Secretary in the case of the Corporation). Either party hereto may change its address for purposes of this Section 8 by giving fifteen (15) days' prior notice to the other party hereto.

9. Severability. If any term or provision of this Agreement or the application hereof to any person or circumstances shall to any extent be invalid or unenforceable, the remainder of this Agreement or the application of such term or provision to persons or circumstances other than those as to which it is held invalid or unenforceable shall not be affected thereby, and each term and provision of this Agreement shall be valid and enforceable to the fullest extent permitted by law.

10. Counterparts. This Agreement may be executed in several counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

11. Governing Law. This Agreement has been executed and delivered in the State of Minnesota and shall, in all respects, be governed by, and construed and enforced in accordance with, the laws of the State of Minnesota, including all matters of construction, validity and performance.

12. Effect of Agreement; Entire Agreement. The Corporation and You understand and agree that this Agreement is intended to reflect their agreement only with respect to payments and benefits upon termination in certain cases and is not intended to create any obligation on the part of either party to continue employment. This Agreement supersedes any and all other oral or written agreements or policies made relating to the subject matter hereof and constitutes the entire agreement of the parties relating to the subject matter hereof; provided that this Agreement shall not supersede or limit in any way Your rights under any benefit plan, program or arrangements in accordance with their terms.

13. ERISA. For purposes of the Employee Retirement Income Security Act of 1974, this Agreement is intended to be a severance pay employee welfare benefit plan, and not an employee pension benefit plan, and shall be construed and administered with that intention.

IN WITNESS WHEREOF, the Corporation has caused this Agreement to be executed in its name by a duly authorized director and officer, and You have hereunto set Your hand, all as of the date first written above.

OTTER TAIL CORPORATION

By: /s/ Chuck MacFarlane
Chuck MacFarlane
Its: President & CEO

/s/ Jennifer O. Smestad

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Section 5: EX-10.J (EXHIBIT 10.J)

Exhibit 10-J

OTTER TAIL CORPORATION
EXECUTIVE SEVERANCE PLAN

Effective February 6, 2015

S&P Global
Market Intelligence

*** Schedule A amended on January 1, 2018**

OTTER TAIL CORPORATION
EXECUTIVE SEVERANCE PLAN

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OTTER TAIL CORPORATION
EXECUTIVE SEVERANCE PLAN

SECTION 1 - INTRODUCTION

This Otter Tail Corporation Executive Severance Plan (the "Plan") is effective for the benefit of designated Employees of Otter Tail Corporation (the "Corporation") and its affiliates. The Plan is an unfunded employee welfare benefit plan that provides severance benefits to a select group of management or highly compensated employees under the Employee Retirement Income Security Act (ERISA).

The Plan replaces and supersedes all severance agreements, obligations, plans, policies and/or practices of the Employer covering any Employee prior to the date the Employee becomes a Participant as described in Section 3 below, except that the Plan shall not replace or supersede any change in control severance agreement between the Employer and the Employee that provides for severance, termination or other benefits in connection with a change in control or any equity award agreement between the Employer and the Employee.

SECTION 2 - DEFINITIONS

Cause. "Cause" shall mean the termination of the Employee's employment by the Employer based upon (i) the willful and continued failure by the Employee substantially to perform the Employee's duties and obligations (other than any such failure resulting from the Employee's incapacity due to physical or mental illness or any such actual or anticipated failure resulting from the Employee's resignation for Good Reason) or (ii) the willful engaging by the Employee in misconduct which is materially injurious to the Corporation or any of its affiliates, monetarily or otherwise. No action or failure to act on the Employee's part shall be considered "willful" unless done, or omitted to be done, by the Employee in bad faith and without reasonable belief that such action or omission was in the best interests of the Corporation and its affiliates.

Committee. "Committee" shall mean the Compensation Committee of the Board of Directors of the Corporation and any successor thereto. The Committee shall be the "plan administrator" for purposes of section 3(16) of ERISA.

Disability. "Disability" shall mean any physical or mental condition that qualifies the Employee for a disability benefit under the Employer's long-term disability plan.

Employee. An "Employee" shall mean any management or highly compensated employee the Employer (or group or class of such employees) designated by the Committee as an Employee for purposes of this Plan and listed on Schedule A attached hereto, as revised from time to time.

Employer. The "Employer" shall mean, collectively, the Corporation and any affiliate that employs an Employee.

Employment Termination. "Employment Termination" shall have meaning ascribed to that term in Section 3 of the Plan.

Good Reason. "Good Reason" shall mean the occurrence of any of the following actions taken by the Employer (without the Employee's consent) that results in a material negative change to the Employee, except for the occurrence of such action in connection with the termination or reassignment of the Employee for Cause, Disability or death: (i) a breach or alteration of any material term of any employment agreement or change in control agreement to which the Employee is a party without the Employee's consent; (ii) any reduction in the Employee's base pay that (either individually or when aggregated with any prior reductions) equals or exceeds 20%; (iii) a modification of the Employer's incentive compensation program covering the Employee which (either individually or when aggregated with any prior modifications) results in a reduction of 20% or more in combined incentive opportunity at target; or (iv) a material reduction in the aggregate benefits available to the Employee under the retirement programs that apply to the Employee at the time of becoming a participant in this Plan, but excluding 401(k) and ESOP. Any reduction or modification under (ii) and (iii) above shall be disregarded if it is made on the same or substantially similar basis for substantially all senior executives of the Corporation or any affiliate that employs the Employee. For avoidance of doubt, a change in incentive plan metrics does not constitute a modification of incentive opportunity.

Good Reason shall not exist unless the Employee evidences a voluntary resignation for Good Reason by written notice to the Employer given within 30 days after the date of the occurrence of any event that the Employee knows or should reasonably have known constitutes Good Reason for voluntary resignation, and the Employer shall have 30 days from the date the Employer receives the notice to remedy the condition. Such notice need only identify the Employee and set forth in reasonable detail the facts and circumstances claimed to constitute Good Reason. If the Employer fails to timely remedy the condition, the Employee must resign within 10 days following the failure to cure, otherwise the Employee will be deemed to have consented to the action.

Participant. "Participant" shall have the meaning ascribed to that term in Section 3 of the Plan.

Severance Multiplier. The "Severance Multiplier" means the severance multiplier specified in Schedule A applicable to an Employee.

SECTION 3 - ELIGIBILITY FOR SEVERANCE

An Employee will become a "Participant" eligible for severance and other benefits under the Plan if: (a) the Employee has had a termination that qualifies as an "Employment Termination"; (b) the Employee is not a party to a change in control severance agreement with the Employer that provides for severance, termination or other benefits for the same Employment Termination; (c) the Employee has returned all property of the Corporation and its affiliates; (d) the Employee has signed and returned to the Employer a separation agreement in a form acceptable to the Employer, in its sole discretion, on or before the deadline communicated to the Employee; and (e) any revocation period described in such separation agreement has expired.

An Employee will no longer be a Participant once all severance benefits have been provided to such Employee under the Plan.

Employment Termination

An Employment Termination for purposes of severance benefit eligibility shall be the Employee's (i) involuntary employment termination by the Employer without Cause (other than for death or Disability), or (ii) voluntary resignation for Good Reason. An Employee's employment termination for any other reason is not a qualifying Employment Termination under the Plan.

The determination of whether a termination is a qualifying Employment Termination under the Plan will be made by the Committee, in its sole discretion, and such determination will be conclusive.

Separation Agreement the Employee Must Sign

The agreement the Employee must sign will contain a comprehensive release of claims relating to the Employee's employment and termination, along with the following: (i) an agreement not to disparage the Corporation and its affiliates; (ii) an agreement not to compete with the Corporation and/or its affiliates for a period of months following the Employment Termination corresponding to the Employee's Severance Multiplier (*e.g*, if the Severance Multiplier is 1.5, the non-compete period is 18 months, and if the Severance Multiplier is 2, the non-compete period is 24 months, *etc*.); an agreement not to solicit employees or vendors of the Corporation and/or its affiliates for a period of months following the Employment Termination corresponding to the Employee's Severance Multiplier; and an assignment of intellectual property the Employee created or conceived within the scope of the Employee's duties with the Corporation and/or its affiliates. If the Employee breaches the separation agreement in any material respect, the Employee may be required to repay to the Employer the severance benefits provided to the Employee.

SECTION 4 - AMOUNT OF SEVERANCE PAY AND OTHER BENEFITS

Upon an Employment Termination, a Participant will be entitled to a severance benefit equal to the Employee's Severance Multiplier in Schedule A times the sum of: (i) the Employee's annual base salary in effect when the Employment Termination occurs (but disregarding any decrease thereof that constituted "Good Reason"); and (ii) the target

bonus under the Employee's applicable annual bonus plan for the fiscal year in which the Employment Termination occurs (but disregarding any decrease thereof that constituted "Good Reason" and, for avoidance of doubt, excluding any long-term incentive compensation for which the Employee is eligible).

Offsets. The Employer has the right to reduce the Employee's severance pay by any amounts owed by the Employee to the Employer. In addition, if an Employee becomes entitled to or receives any severance, termination or notice payments under any Federal, State or other law (for example, any WARN law, but excluding state unemployment compensation benefits) or otherwise, the Employee's severance pay under the Plan will be reduced by the amount of such other payments paid or payable.

SECTION 5 - WHEN SEVERANCE PAY WILL BE PAID

Severance pay under the Plan will be paid to the Employee in a lump sum as soon as practicable (generally, within two pay periods) after the Employee signs the required separation agreement and any revocation period under such separation agreement has expired, subject to the limitations under Section 6.H. below.

SECTION 6 - MISCELLANEOUS PROVISIONS

A. Amendment and Termination. The Corporation reserves the right, in its sole discretion, to amend or terminate the Plan, in whole or in part, at any time and for any reason; provided that no amendment or termination may materially and adversely alter or impair an Employee's rights or benefits under this Plan without the written consent of the Employee.

B. Severability. If any of the Plan's provisions are found to be unlawful, such finding will not affect the Plan's other provisions unless such finding makes impossible or impracticable the Plan's functioning, in which case appropriate provisions will be adopted so that the Plan may continue to function.

C. Incompetency. If the Committee finds that a Participant is unable to care for his/her affairs, and a claim for Plan benefits has not been made by a duly appointed legal representative, such benefits may be paid in any manner the Committee determines, and such payment will be a complete discharge of liability for Plan benefits to which such Participant was entitled.

D. Not an Employment Contract. Nothing contained in this Plan is intended to create any liability of the Employer to retain any Employee in its service. All Employees remain subject to termination as if the Plan had not been established.

E. Financing. Severance benefits payable under the Plan will be paid out of the general assets of the Employer. No Participant's right to receive payments under the Plan will be secured by any assets of the Corporation or its affiliates.

F. Nontransferability. A Participant has no right to assign or otherwise dispose of any interest under the Plan, nor may any right be assigned or transferred by operation of law.

G. Legally-Required Withholdings. Benefits under the Plan will be subject to all legally-required withholdings, including tax withholdings.

H. 409A Limitation. The Plan is intended to qualify as an involuntary separation arrangement that is exempt from section 409A of the Internal Revenue Code ("Section 409A"). Specifically, any benefits paid within the Applicable 2-1/2 Month Period (as defined below) are intended to constitute separate payments (for purposes of Treasury Regulation § 1.409A-2(b)(2)) that are exempt from Section 409A pursuant to the "short-term deferral" rule set forth in Treasury Regulation § 1.409A-1(b)(4). To the extent that any benefits do not qualify for the foregoing exemptions, such benefits are intended to be exempt from section 409A under the "involuntary separation pay plan" exception set forth in Treasury Regulation § 1.409A-1(b)(9)(iii), up to the maximum extent permitted by said provision (generally, two times the lesser of the Employee's annualized compensation or the compensation limit then in effect under section 401(a)(17) of the Code). Benefits in excess of the maximum shall be delayed as necessary to avoid application of Section 409A (unless otherwise exempt). The term "Employment Termination" shall be interpreted to mean a "separation from service" as that term is defined under Section 409A to the extent necessary to qualify the arrangement as an involuntary separation arrangement. "Applicable 2-1/2 Month Period" means the period beginning upon the Employee's Employment Termination and ending 2-1/2 months after the later of (i) the end of the calendar year in which the Employee's Employment Termination occurred, or (ii) the end of the Employer's fiscal year in which the Employee's Employment Termination occurred.

I. Governing Law. To the extent not preempted by federal law, this Plan shall be governed by and construed in accordance with the internal laws of the State of Minnesota, without giving effect to the conflicts of laws principles thereof.

SECTION 7 - ADMINISTRATION

A. Claim Procedure. An individual who believes he/she is eligible for benefits under the Plan, or believes he/she is eligible for benefits that are different from those being offered to the individual, may submit a written claim with the Committee. Any such claim must be submitted within 180 days after the employment termination upon which the claim is based, and any claim submitted after that period will be denied as untimely. The claim will be reviewed by one or more individuals appointed by the Committee to serve as the claim administrator under the Plan.

The claimant will be informed of the claim administrator's decision regarding the claim within 90 days after it is filed. Under special circumstances, the claim administrator may require an additional period of not more than 90 days to review a claim. If this occurs, the claimant will be notified in writing as to the length of the extension, the reason for the extension, and any other information needed in order to process the claim. If a claimant is not notified within the 90-day period (or 180-day period, if so extended), the claimant may consider the claim to be denied.

If a claim is denied, in whole or in part, the claimant will be notified in writing of the specific reason(s) for the denial, the Plan provision(s) on which the decision was based, what additional material or information is relevant to the case and what procedure the claimant should follow to get the claim reviewed again. The claimant then has 60 days to appeal the decision to the Committee. The appeal must be submitted in writing to the Committee. A claimant may request to review pertinent documents and may submit a written statement of issues and comments.

A decision as to a claimant's appeal will be made within 60 days after the appeal is received. Under special circumstances, the Committee may require an additional period of not more than 60 days to review an appeal. If this occurs, the claimant will be notified in writing as to the length of the extension, not to exceed 120 days from the day on which the appeal was received.

If a claimant's appeal is denied, in whole or in part, the claimant will be notified in writing of the specific reason(s) for the denial and the Plan provision(s) on which the

decision was based. The Committee's decision on an appeal will be final and binding on all parties and persons affected. If a claimant is not notified within the 60-day (or 120-day, if so extended) period, the claimant may consider the appeal to be denied.

The claim procedure in the Plan, including appeals, must be fully exhausted and a final determination made by the Committee before a claimant may file a lawsuit based on a denial of Plan benefits. Any lawsuit for Plan benefits must be filed within one year after the Committee's final determination of the claim for benefits.

B. Plan Interpretations and Benefit Determinations. The Plan is administered and operated by the Committee who has complete authority and sole discretion to interpret the Plan's terms (and any related documents), and to determine eligibility for, and amounts of, benefits under the Plan. All such interpretations and determinations (including factual determinations) by the Committee will be final and binding upon affected parties.

The Committee may, subject to limitations under applicable law or securities exchange rules, delegate such powers and duties as are deemed desirable to the Chief Executive Officer or one or more other individuals, in which case every reference made to the Committee will be deemed to mean or include such individuals as to matters within their jurisdiction.

If any individual to whom authority has been delegated hereunder shall also be an Employee in the Plan, the individual shall have no authority with respect to any matter specially affecting his or her individual interest in the Plan.

C. Miscellaneous.

- THE PLAN'S SPONSOR:

  Otter Tail Corporation
  4334 18th Avenue SW
  Suite 200
  Fargo, ND 58103

- AGENT FOR SERVICE OF LEGAL PROCESS:

  General Counsel
  Otter Tail Corporation
  4334 18th Avenue SW
  Suite 200
  Fargo, ND 58103

S&P Global Market Intelligence

SCHEDULE A

Name	Severance Multiplier	Date Added
Timothy J. Rogelstad	1.5	2/06/2015
Paul Knutson	1.5	2/06/2015
Chuck MacFarlane	2.0	4/13/2015
John Abbott	1.5	4/13/2015
Jennifer Smestad	1.5	1/1/2018

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Section 6: EX-12.1 (EXHIBIT 12.1)

Exhibit 12.1

OTTER TAIL CORPORATION
CALCULATION OF RATIOS OF EARNINGS TO FIXED CHARGES AND PREFERRED DIVIDENDS

	Year Ended December 31,				
	2013	2014	2015	2016	2017
Earnings					
Pretax income from continuing operations	$ 71,363,651	$ 73,440,180	$ 80,231,110	$ 82,118,038	$ 99,162,305
Plus fixed charges (see below)	30,219,768	32,091,737	33,742,169	34,311,441	31,936,730
Total earnings (1)	$ 101,583,419	$ 105,531,917	$ 113,973,279	$ 116,429,479	$ 131,099,035
Fixed Charges					
Interest charges	$ 26,820,365	$ 29,241,350	$ 30,817,357	$ 31,291,356	$ 29,305,659

Amortization of debt expense, premium and discount	1,155,403	1,095,387	1,065,812	1,089,085	1,039,071
Estimated interest component of operating leases	2,244,000	1,755,000	1,859,000	1,931,000	1,592,000
Total fixed charges (2)	$ 30,219,768	$ 32,091,737	$ 33,742,169	$ 34,311,441	$ 31,936,730
Preferred Dividend Requirement*	$ 650,239	$ -	$ -	$ -	$ -
Total Fixed Charges and Preferred Dividend Requirement (3)	$ 30,870,007	$ 32,091,737	$ 33,742,169	$ 34,311,441	$ 31,936,730
Ratio of Earnings to Fixed Charges (1) Divided by (2)	3.36	3.29	3.38	3.39	4.10
Ratio of Earnings to Fixed Charges and Preferred Dividends (1) Divided by (3)	3.29	3.29	3.38	3.39	4.10

** All outstanding cumulative preferred shares were redeemed on March 1, 2013 for $15.7 million, including $0.2 million in call premiums charged to equity and included as preferred dividends paid and as part of our preferred dividend requirement for the year ended December 31, 2013.*

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Section 7: EX-21.A (EXHIBIT 21.A)

Exhibit 21-A

OTTER TAIL CORPORATION

Subsidiaries of the Registrant
February 20, 2018

Company	State of Organization
Otter Tail Power Company	Minnesota
Otter Tail Assurance Limited	Cayman Islands
Varistar Corporation	Minnesota
Northern Pipe Products, Inc.	North Dakota
Vinyltech Corporation	Arizona
T.O. Plastics, Inc.	Minnesota
BTD Manufacturing, Inc.	Minnesota
IMD, Inc.	North Dakota
Shrco, Inc.	Minnesota

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Section 8: EX-23.A (EXHIBIT 23.A)

Exhibit 23-A

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-204041 and 333-204042 on Form S-3, Registration Statement No. 333-181362, 333-195337, and 333-204043 on Form S-8 of our report dated February 20, 2018, relating to the consolidated financial statements and financial statement schedule of Otter Tail Corporation and subsidiaries, and the effectiveness of Otter Tail Corporation and subsidiaries' internal control over financial reporting, appearing in the Annual Report on Form 10-K of Otter Tail Corporation and subsidiaries for the year ended December 31, 2017.

/s/ Deloitte & Touche LLP

Minneapolis, MN

February 20, 2018
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Section 9: EX-24.A (EXHIBIT 24.A)

Exhibit 24-A

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints CHARLES S. MACFARLANE, KEVIN G. MOUG, and JENNIFER O. SMESTAD, and each of them, his or her true and lawful attorneys-in-fact and agents, each acting alone, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign the Annual Report on Form 10-K of Otter Tail Corporation for its fiscal year ended December 31, 2017, and any and all amendments to said Annual Report, and to deliver on my behalf said Annual Report and any and all amendments thereto, as each thereof is so signed, for filing with the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended, granting unto said

attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite or necessary to be done in and about the premises, as fully as to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his substitutes, may lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, this Power of Attorney has been signed on the 6th day of February, 2018 by the following persons:

/s/ Karen M. Bohn
Karen M. Bohn

/s/ John D. Erickson
John D. Erickson

/s/ Steven L. Fritze
Steven L. Fritze

/s/ Kathryn O. Johnson
Kathryn O. Johnson

/s/ Charles S. MacFarlane
Charles S. MacFarlane

/s/ Kevin G. Moug
Kevin G. Moug

/s/Timothy J. O'Keefe
Timothy J. O'Keefe

/s/Nathan I. Partain
Nathan I. Partain

/s/ Joyce Nelson Schuette
Joyce Nelson Schuette

/s/ James B. Stake
James B. Stake

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Section 10: EX-31.1 (EXHIBIT 31.1)

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Charles S. MacFarlane, certify that:

1. I have reviewed this Annual Report on Form 10-K of Otter Tail Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2018

/s/ Charles S. MacFarlane
Charles S. MacFarlane
President and Chief Executive Officer
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Section 11: EX-31.2 (EXHIBIT 31.2)

Exhibit 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Kevin G. Moug, certify that:

1. I have reviewed this Annual Report on Form 10-K of Otter Tail Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 20, 2018

/s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer and Senior Vice President
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Section 12: EX-32.1 (EXHIBIT 32.1)

Exhibit 32.1

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Otter Tail Corporation (the "Company") on Form 10-K for the period ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Charles S. MacFarlane, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Charles S. MacFarlane
Charles S. MacFarlane
President and Chief Executive Officer
February 20, 2018

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Section 13: EX-32.2 (EXHIBIT 32.2)

Exhibit 32.2

CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Otter Tail Corporation (the "Company") on Form 10-K for the period ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Kevin G. Moug, Chief Financial Officer and Senior Vice President of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Kevin G. Moug
Kevin G. Moug
Chief Financial Officer and Senior Vice President
February 20, 2018

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S&P Global
Market Intelligence

Blue Chip Financial Forecasts®

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

Vol. 37, No. 5, May 1, 2018

Wolters Kluwer

BLUE CHIP FINANCIAL FORECASTS®

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Next FOMC Rate Hike To Come In June, Probably Two More After In 2018

Domestic Commentary The Federal Open Market Committee's (FOMC) May 1st-2nd meeting is expected to be something of a yawner. There likely will be some minor tinkering with the policy statement, noting that the economy remains strong, labor markets firm, and that the pace of inflation has picked up. There seems little likelihood of changes to the balance of risks or the Committee's stated belief that current policy remains "accommodative." None of our panelists predict a hike in interest rates at the meeting, according to our April 25th-26th survey. Instead, 95.1% of the panelists believe the next rate hike from the FOMC will come at its June 12th-13th meeting. The other 4.9% predict that the FOMC will hold off until its September 25th-26th meeting to enact its second rate hike of 2018.

After raising its target range for the federal funds rate by 25 basis points to 1.50%-1.75% at its March meeting only 2.5% of the panelists now predict that the FOMC will increase interest rates just once more this year, while 37.5% now foresee a total of 75 basis points of increases this year, and 60% forecast a total of 100 basis points of rate hikes in 2018.

Last month, 9.5% of the panelists predicted only one more 25 basis point rate hike this year, 35.7% foresaw two more 25 point increases, and 54.8% predicted three more 25 basis point increases, bringing the total increase in 2018 to 100 basis points.

In 2019, 2.6% of the panelists currently predict the FOMC will leave interest rates unchanged, 10.3% forecast one 25 basis point increase, 28.2% foresee 50 basis points of rate hikes, 33.3% expect 75 basis points of increases, and 25.6% anticipate a full 100 basis points of increases in the interest rates by policymakers.

Asked this month to predict the terminal level for the federal funds rate during the FOMC's current tightening cycle, the consensus forecasts 3.22%, with an average of the 10 highest forecasts coming in at 4.09%, and an average of the 10 lowest forecasts at 2.46%.

Our panelists' current forecasts of expected changes in FOMC policy this year and next align fairly closely with median expectations of FOMC members contained in the March Summary of Economic Projections. While the median forecast of the so-called "dot plot" had suggested since the December meeting a total of three 25 basis point rate hikes by the end of 2018, the March meeting's mean forecast rose by just enough to almost suggest 100 basis points of tightening this year. While six FOMC policymakers in December thought the federal funds rate would remain below 2.0% at the end of 2018, now only two think so and three policymakers that had anticipated 75 basis points of rate hikes in 2018 now expect four increases.

The FOMC's March dot plot also indicated a steeper than previously anticipated trajectory for the federal funds rate in 2019 with the median forecast suggesting three 25 basis point increases next year rather than the previous forecast of slightly more than two. As this month's survey suggested, not quite 60% of our panelists now forecast at least 75 basis points of additional rate hikes next year.

Diving expectations that FOMC policymakers are likely to continue normalizing interest rates this year and next is a belief that despite a marked slowdown in real GDP growth during Q1 of this year the outlook for the economy remains upbeat and that inflation is firming.

Job growth remains healthy and well in excess of population increases, the unemployment rate is at an 18-year low, wage growth is picking up, consumer and business confidence remain high, and financial conditions remain supportive Moreover, the economy is poised to get a considerable fiscal boost this year and next from the tax cuts and large budget increase enacted by Congress.

The Consumer Price Index is now running at 2.4% (y/y) and the core CPI at 2.1% (y/y). The price index for personal consumption expenditures (PCE) and the core PCE price index are on the verge of hitting the 2.0% level, the latter for the first time since April 2012. The latest Employment Cost Index data showed that private sector employment cost increases rose in every quarter since a 2.2% reading in Q4 2016 with the 2.8% y/y reading in Q1 of this year being the fastest in the private ECI since the third quarter of 2008.

Real GDP grew 2.3% (saar) in Q1, according to the initial estimate from the Bureau of Economic Analysis. That is little different than last month's consensus forecast of 2.2%, but more moderate than the average pace of 3.0% registered in the prior three quarters. However, most analysts view the Q1 softness as attributable to residual seasonality issues, delays in tax refunds, a harsher than usual winter, and an inevitable cooling after a boost to GDP in Q4 as the economy recovered from a hurricane-induced hit to activity.

The most notable drag on Q1 GDP was the paltry 1.1% (saar) gain in real PCE, the slowest pace in four and a half years, and a distinct softening compared to Q4's robust 4.0% (saar) growth rate. All of the slowdown in PCE was accounted for by a -1.1% (saar) contraction in spending on consumer goods, Real nonresidential fixed investment grew a respectable 6.1% (saar) in Q1, but real residential investment flat lined after surging 12.8% (saar) in Q4 of last year. The change in inventories contributed 0.4 of a percentage point to real GDP's rate of growth in Q1, while government spending and consumption added 0.2 of a percentage point. The biggest surprise was that real net exports also contributed 0.2 of a percentage point to real GDP's rate of growth during the quarter. Monthly data had most analysts predicting that trade would subtract from GDP. The GDP price index grew 2.0% (saar) in Q1; the PCE price index 2.7% for a second, straight quarter.

Looking forward, the consensus forecasts that real GDP growth will rebound to 3.1% (saar) in Q2, 3.0% in Q3, and 2.9% in Q4 of this year, the latter 0.1 of a percentage point greater than predicted a month ago. In 2019, the consensus predicts real GDP growth of 2.5% (saar) in Q1, 2.4% in Q2 and 2.2% in Q3.

The annualized change in the GDP price index during the next six quarters is predicted by the consensus to hover in the vicinity of 2.1%-2.2%, little different than over the prior three quarters. However, the annualized change in the CPI is expected to moderate to a similar average of 2.1%-2.2% versus the 3.4% average during Q4 2017 and Q1 2018. In answer to a special question, the consensus forecast that the PCE price index would register December-over-December increases of 2.1% in 2018 and 2019 versus 1.7% in 2017.

During the final week of April the 2-year Treasury note yield hit the 2.5% level for the first time since September 2008 and the 10-year Treasury note yield breached the "psychologically important" 3.0% level for the first time since January 2014. Short interest in the 10-year market has reached pretty high levels, so pushing the yield much higher in the short-term may be tough. Nonetheless, short and long-term rates are expected by our panelists to continue upwards over the course of this year and into next.

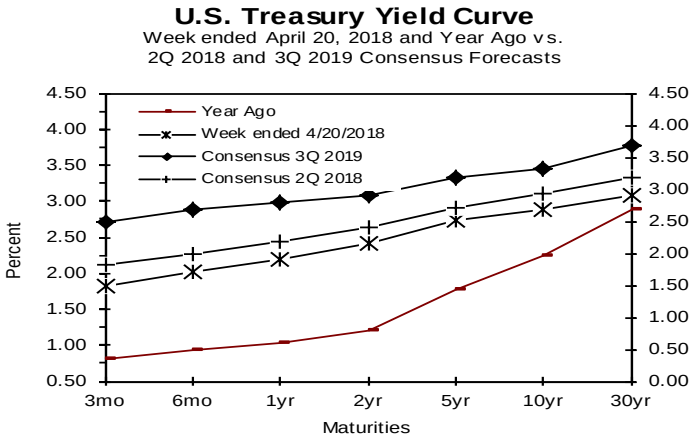
Consensus Forecast Real GDP growth will average 3.0% (saar) over the remaining three quarters of 2018, but moderate to about 2.3% during the first three quarters of 2019. Job growth will remain healthy and wage gains will increase. Inflation on a y/y basis will continue to inch higher, meeting, and then exceeding somewhat the FOMC's 2.0% target. The FOMC will stick with its interest rate normalization process, most likely hiking rates by another 75 basis points this year and by an additional 75 basis points in 2019. The trade-weighted value of the U.S. dollar has stabilized after falling last year, but much of an upward bounce seems remote *(see page 2).*

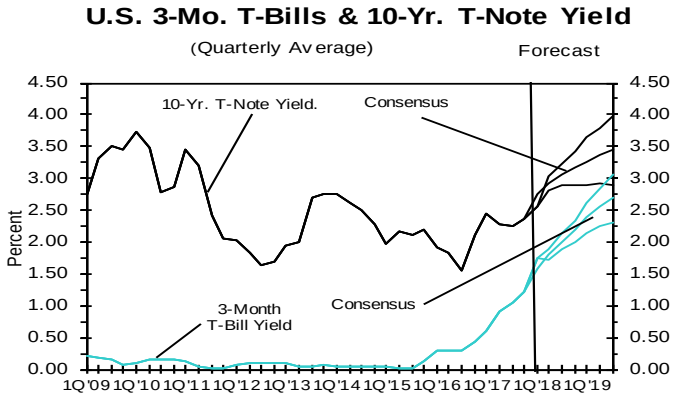
Special Questions The consensus puts the odds of U.S. recession beginning this year at 13.9% and a recession beginning next year at 25.0%. The unemployment rate will fall to 3.7% in December of this year and to 3.6% in December 2019 *(see page 14).*

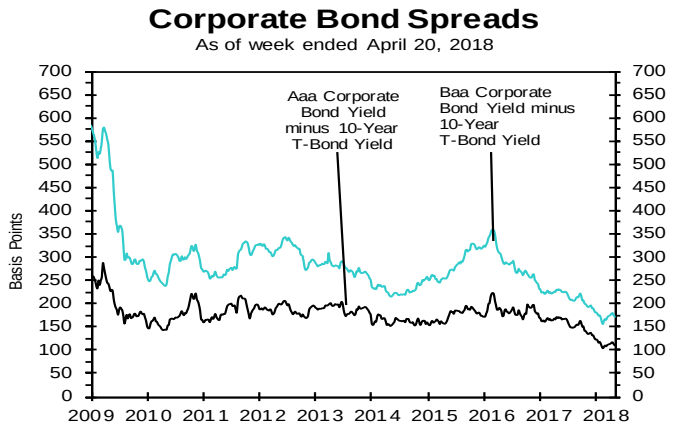
Consensus Forecasts Of U.S. Interest Rates And Key Assumptions[1]

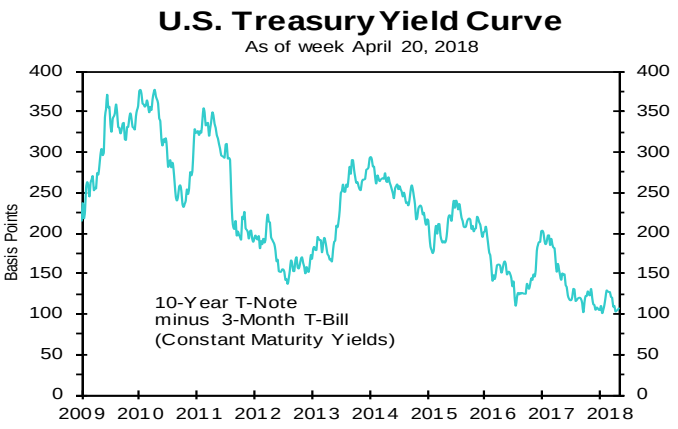
Interest Rates	Apr. 20	Apr. 13	Apr. 6	Mar. 30	Mar	Feb	Jan	1Q 2018	2Q 2018	3Q 2018	4Q 2018	1Q 2019	2Q 2019	3Q 2019
	History: Average For Week Ending				History: Average For Month			Latest Qtr	Consensus Forecasts-Quarterly Avg.					
Federal Funds Rate	1.69	1.69	1.68	1.68	1.49	1.42	1.41	1.44	**1.7**	**2.0**	**2.2**	**2.4**	**2.6**	**2.8**
Prime Rate	4.75	4.75	4.75	4.75	4.75	4.50	4.50	4.58	**4.8**	**5.0**	**5.2**	**5.4**	**5.6**	**5.8**
LIBOR, 3-mo.	2.36	2.34	2.32	2.30	2.16	1.84	1.73	1.91	**2.3**	**2.4**	**2.6**	**2.8**	**2.9**	**3.1**
Commercial Paper, 1-mo.	1.83	1.81	1.83	1.86	1.76	1.52	1.50	1.59	**1.8**	**2.1**	**2.3**	**2.5**	**2.7**	**2.9**
Treasury bill, 3-mo.	1.81	1.75	1.74	1.76	1.72	1.56	1.43	1.57	**1.8**	**2.0**	**2.2**	**2.4**	**2.6**	**2.7**
Treasury bill, 6-mo.	2.01	1.95	1.92	1.94	1.91	1.76	1.62	1.76	**2.0**	**2.2**	**2.4**	**2.6**	**2.7**	**2.9**
Treasury bill, 1 yr.	2.18	2.10	2.07	2.09	2.06	1.94	1.80	1.93	**2.2**	**2.3**	**2.5**	**2.7**	**2.9**	**3.0**
Treasury note, 2 yr.	2.42	2.33	2.28	2.29	2.27	2.16	2.02	2.15	**2.4**	**2.6**	**2.7**	**2.9**	**3.0**	**3.1**
Treasury note, 5 yr.	2.73	2.64	2.60	2.59	2.63	2.59	2.36	2.53	**2.7**	**2.9**	**3.0**	**3.1**	**3.2**	**3.3**
Treasury note, 10 yr.	2.88	2.80	2.78	2.79	2.85	2.84	2.56	2.75	**2.9**	**3.1**	**3.2**	**3.3**	**3.4**	**3.5**
Treasury note, 30 yr.	3.07	3.02	3.02	3.02	3.10	3.11	2.86	3.02	**3.2**	**3.3**	**3.5**	**3.6**	**3.7**	**3.8**
Corporate Aaa bond	3.98	3.93	3.95	3.95	3.98	3.91	3.68	3.86	**4.0**	**4.2**	**4.4**	**4.6**	**4.7**	**4.8**
Corporate Baa bond	4.60	4.55	4.58	4.58	4.59	4.47	4.24	4.43	**4.8**	**5.0**	**5.2**	**5.3**	**5.4**	**5.5**
State & Local bonds	3.63	3.62	3.62	3.62	3.61	3.57	3.42	3.53	**3.8**	**3.9**	**4.0**	**4.1**	**4.3**	**4.4**
Home mortgage rate	4.47	4.42	4.40	4.44	4.44	4.33	4.03	4.27	**4.5**	**4.7**	**4.8**	**4.9**	**5.0**	**5.1**
	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	History				Consensus Forecasts-Quarterly	
Key Assumptions	2016	2016	2016	2017	2017	2017	2017	2018	**2Q 2018**	**3Q 2018**	**4Q 2018**	**1Q 2019**	**2Q 2019**	**3Q 2019**
Major Currency Index	89.6	90.3	93.7	94.4	93.0	88.3	88.9	86.1	**86.6**	**86.7**	**86.7**	**86.7**	**86.5**	**86.6**
Real GDP	2.2	2.8	1.8	1.2	3.1	3.2	2.9	2.3	**3.1**	**3.0**	**2.9**	**2.5**	**2.4**	**2.2**
GDP Price Index	2.4	1.4	2.0	2.0	1.0	2.1	2.3	2.0	**2.0**	**2.2**	**2.1**	**2.2**	**2.2**	**2.3**
Consumer Price Index	2.7	1.8	2.7	3.0	0.1	2.1	3.3	3.5	**1.9**	**2.3**	**2.1**	**2.2**	**2.2**	**2.3**

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; LIBOR quotes from Intercontinental Exchange. All interest rate data is sourced from Haver Analytics. Historical data for Fed's Major Currency Index is from FRSR H.10. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS).









----------3-Month Interest Rates[1]----------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	2.36	2.25	2.25	**2.09**	**2.21**	**2.36**
Japan	-0.03	-0.05	-0.05	**0.02**	**0.02**	**0.03**
U.K.	0.75	0.62	0.62	**0.83**	**0.83**	**0.96**
Switzerland	-0.73	-0.74	-0.74	**-0.75**	**-0.75**	**-0.75**
Canada	1.69	1.67	1.67	**1.78**	**1.95**	**2.08**
Australia	2.14	2.03	2.03	**1.80**	**1.90**	**2.20**
Eurozone	-0.33	-0.33	-0.33	**-0.33**	**-0.32**	**-0.23**

----------10-Yr. Government Bond Yields[2]------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	2.98	2.82	2.82	**3.01**	**3.13**	**3.27**
Germany	0.63	0.59	0.59	**0.70**	**0.81**	**1.03**
Japan	0.04	0.01	0.01	**0.06**	**0.07**	**0.08**
U.K.	1.59	1.49	1.49	**1.64**	**1.75**	**1.98**
France	0.84	0.81	0.81	**0.93**	**1.06**	**1.29**
Italy	1.78	1.95	1.95	**1.98**	**2.09**	**2.33**
Switzerland	0.18	0.11	0.11	**0.14**	**0.23**	**0.40**
Canada	2.37	2.26	2.26	**2.49**	**2.68**	**2.87**
Australia	2.87	2.70	2.70	**2.83**	**2.93**	**3.06**
Spain	1.25	1.26	1.26	**1.47**	**1.61**	**1.86**

----------Foreign Exchange Rates[1]----------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	86.376	86.757	86.757	**87.5**	**87.5**	**87.3**
Japan	107.60	106.10	106.10	**107.5**	**107.9**	**108.8**
U.K.	1.4033	1.3919	1.3919	**1.40**	**1.41**	**1.45**
Switzerland	0.9744	0.9532	0.9532	**0.97**	**0.97**	**0.96**
Canada	1.2740	1.3096	1.3096	**1.27**	**1.26**	**1.24**
Australia	0.7671	0.7733	0.7733	**0.76**	**0.77**	**0.78**
Euro	1.2282	1.2280	1.2280	**1.23**	**1.23**	**1.26**

	Consensus 3-Month Rates vs. U.S. Rate			Consensus 10-Year Gov't Yields vs. U.S. Yield	
	Now	In 12 Mo.		Now	In 12
Japan	-2.66	**-2.34**	Germany	-2.35	**-2.25**
U.K.	-1.61	**-1.40**	Japan	-2.94	**-3.19**
Switzerland	-3.09	**-3.11**	U.K.	-1.39	**-1.29**
Canada	-0.67	**-0.29**	France	-2.14	**-1.98**
Australia	-0.22	**-0.16**	Italy	-1.20	**-0.94**
Eurozone	-2.69	**-2.59**	Switzerland	-2.80	**-2.88**
			Canada	-0.61	**-0.41**
			Australia	-0.11	**-0.21**
			Spain	-1.73	**-1.42**

Forecasts of panel members are on pages 10 and 11. Definitions of variables are as follows: [1]Three month rate on interest-earning money market deposits denominated in selected currencies. [2]Government bonds are yields to maturity. Foreign exchange rate forecasts for U.K., Australia and the Euro are U.S. dollars per currency unit. For the U.S dollar, forecasts are of the U.S. Federal Reserve Board's Major Currency Index.

International Commentary The odds of a May 10th rate hike by the Bank of England's Monetary Policy Committee (MPC) fell sharply in the wake of a weaker-than-expected preliminary estimate of economic growth in Q1. Indeed, markets now do not expect a rate hike until Q4. Real GDP grew just 0.4% (ar) during the quarter, well short of consensus expectations of 1.2% growth and the weakest quarterly performance since Q4 2012. Growth in services slowed to 0.3% (q/q), construction output contracted 3.3% (q/q), while industrial production rose 0.7% (q/q). Worse than usual winter conditions likely dampened personal consumption and construction activity, but the overall effects on GDP were thought to be limited, thus raising questions among some analysts about the underlying health of the economy. Nonetheless, the consensus expects the pace of GDP growth to bounce back this quarter given that unemployment is at its lowest level since 1975 and wage growth rose to its fastest pace in almost three years in the three month's ending in February. Moreover, inflation continues to fall, dropping to 2.5% in March, the lowest level in a year. This has helped lift real income growth. Still a threat, however, are contentious Brexit negotiations that hold the potential to dampen GDP growth later this year, complicating MPC efforts to further normalize interest rates.

As expected, the Bank of Canada (BoC) left its overnight policy rate unchanged at 1.25% in April. The BoC has raised rates three times since July 2017, most recently at its January meeting. Since then, signs of softer than expected economic activity have emerged. Real GDP fell 0.1% in January and employment suffered a rare decline in February. Nonetheless, the economy is thought to be running at close to capacity with unemployment at a 40-year low and consumer price inflation now at 2.3%, (y/y), the highest since late 2014. In testimony before the Senate banking Committee on April 25th BoC Governor Stephen Poloz said the economy was "finally positive" after a long adjustment to the previous sharp fall in oil prices, but added there was still softness in several areas of the country. Poloz reiterated that while higher interest rates would likely be warranted over time, some policy accommodation was still required to keep inflation on track. Most analysts are looking for two more quarter point hikes in rates this year and more in 2019 if inflation does not begin fall back toward 2.0%.

The European Central Bank (ECB) maintained its current policy at its April meeting, leaving rates unchanged and saying it will keep its asset purchases of 30 billion euros per month until at least September. Economic growth during Q1 appears to have been softer than expected, something on the order of 1.5% (ar) versus 2.7% in Q4 of last year. A harsh winter was likely a factor and most analysts look for a nice rebound in the Eurozone's Q2 real GDP growth rate to a bit more than 2.0%. Stubbornly low inflation, however, will likely keep the ECB cautious. That said, most analysts continue to assume that the ECB will begin to taper the size of its monthly asset purchases in September of this year and start to raise interest rates in Q2 of 2019. Given that trade accounts for 44% of GDP, an escalation in trade tensions and the strength of the Euro, are the biggest threats to the consensus outlook for ECB policy.

The Bank of Japan (BoJ) also left policy unchanged at its April meeting, voting 8-1 to maintain its target for 10-year JGB yields near zero, its short-term deposit rate at -0.1%, and the continuation of its annual bond purchase program of 80 trillion yen. The big news was the BoJ's abandonment of when it hoped to hit its 2.0% inflation target. The BoJ had pushed forward its target date for reaching the 2.0% target six times before finally removing it in April. Most analysts interpreted the news as meaning the BoJ would stick with its easing program for even longer than expected. However, a few suggested that by removing the target it could pave the way for the bank to become less accommodative sooner than expected. Economic growth appears to have grown very little in Q1, in part due to weather, but should bounce back in Q2. Core inflation is currently running at 0.9% (y/y) *(see pages 10-11 for individual panelists' forecasts).*

Second Quarter 2018

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter															Avg. For	(Q-Q % Change)		
	Short-Term							Intermediate-Term				Long-Term				Qtr.	(SAAR)		
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Chase Wealth Management	1.9 H	5.0 H	2.1	2.0 H	1.9	2.1 H	2.3 H	2.5	2.9 H	3.0	3.2	4.1	4.8	3.7	4.6	86.2	3.0	2.0	2.1
ACIMA Private Wealth	1.9 H	4.9	2.4	2.0 H	1.9	2.1 H	2.2	2.6 H	2.9 H	3.0	3.2	4.0	4.9	3.9	4.6	85.5 L	2.2	2.3	3.0
Swiss Re	1.9 H	4.9	2.2	1.9	1.8	1.9	2.1 L	2.3 L	2.5 L	2.8 L	3.1	4.1	5.0	na	4.6	na	3.0	1.5	0.1 L
Bank of America Merrill Lynch	1.9 H	na	2.4	na	2.0 H	na	na	2.5	2.9 H	3.0	3.2	na	na	na	na	na	3.7	1.8	1.6
RBC Capital Markets	1.9 H	na	na	na	na	na	na	2.4	2.7	3.0	3.4	na	na	na	na	na	3.6	1.7	1.9
J.P. Morgan Chase	1.9 H	na	2.3	na	na	na	na	2.4	2.7	2.9	3.1	na	na	na	na	na	2.3	2.0	1.9
BNP Paribas Americas	1.9 H	na	2.1	na	na	na	na	2.5	2.9	3.1	na	na	na	na	na	na	4.2	na	1.1
Barclays	1.9 H	5.0 H	na	na	na	na	na	2.4	2.6	2.8 L	3.0 L	na	na	na	na	na	3.0	2.1	1.7
MacroFin Analytics	1.8	4.8	2.4	1.8	1.9	2.1 H	2.3 H	2.5	2.9 H	3.0	3.2	4.0	4.8	3.8	4.5	86.9	1.9 L	2.0	1.9
Daiwa Capital Markets America	1.8	4.8	2.5	1.8	1.9	2.1 H	2.2	2.5	2.8	3.0	3.2	4.0	4.8	na	4.6	86.0	2.8	2.1	1.5
Nomura Securities, Inc.	1.8	4.9	2.4	na	na	na	na	2.5	2.8	3.0	na	4.1	4.6 L	na	na	na	3.1	1.8	1.9
Goldman Sachs & Co.	1.8	na	2.2	na	1.7 L	na	na	2.3 L	2.7	2.9	3.1	na	na	na	4.3 L	na	3.3	1.8	2.0
Societe Generale	1.8	4.8	na	na	1.9	na	na	2.4	2.7	2.9	3.0 L	na	na	na	na	na	2.6	2.0	2.4
AIG	1.8	4.8	na	na	1.8	2.0	2.1 L	2.4	2.7	2.9	3.1	na	4.7	na	4.5	na	2.9	2.1	2.5
Via Nova Investment Mgt.	1.8	4.8	2.5 H	1.7 L	1.7 L	1.8 L	2.1 L	2.3 L	2.8	3.0	3.3	4.2	4.6 L	3.9	4.6	87.0	3.1	2.1	2.5
NatWest Markets	1.7 L	4.8	2.4	1.8	1.8	2.0	2.2	2.3 L	2.5 L	2.8 L	3.2	4.1	4.7	3.8	4.6	87.0	3.0	1.7	1.2
DePrince & Assoc.	1.7 L	4.8	2.3	1.9	1.8	2.0	2.1 L	2.4	2.8	3.0	3.2	4.1	4.9	4.1 H	4.8 H	86.8	2.9	2.1	2.1
Regions Financial Corporation	1.7 L	4.7 L	2.4	1.9	1.9	2.1 H	2.2	2.5	2.8	3.0	3.2	4.1	4.8	3.9	4.5	86.3	3.6	2.0	2.3
Loomis, Sayles & Company	1.7 L	4.8	2.3	1.9	1.9	2.1 H	2.2	2.4	2.7	2.9	3.1	3.9	4.7	3.6	4.4	86.2	3.3	1.7	1.6
Amherst Pierpont Securities	1.7 L	4.8	2.4	1.9	1.8	2.0	2.2	2.5	2.8	3.0	3.3	4.1	4.9	4.0	4.6	88.0	4.3 H	2.3	1.8
Georgia State University	1.7 L	4.8	na	na	1.7 L	2.0	2.2	2.4	2.8	3.1 H	3.2	4.2	4.8	na	4.5	na	4.0	2.0	2.5
Grant Thornton/Diane Swonk	1.7 L	4.8	2.0	1.8	1.7 L	2.0	2.1	2.4	2.7	2.9	3.1	3.4 L	4.7	3.4 L	4.5	87.6	2.9	1.5	1.2
Action Economics	1.7 L	4.8	1.9	1.8	1.9	2.0	2.1 L	2.5	2.7	2.9	3.1	3.9	4.7	3.7	4.5	86.1	3.6	2.3	1.9
BMO Capital Markets	1.7 L	4.8	2.4	na	1.9	2.1 H	2.2	2.4	2.7	2.9	3.1	na	na	na	4.5	86.3	2.8	1.8	2.0
Economist Intelligence Unit	1.7 L	4.7 L	1.7 L	1.9	1.9	2.0	2.2	2.5	2.8	3.0	3.3	na	na	na	4.6	na	2.8	na	2.2
Moody's Analytics	1.7 L	4.8	2.1	1.7 L	1.7 L	1.9	2.2	2.4	2.8	3.1 H	3.9 H	4.6 H	5.5 H	3.7	4.7	na	3.3	2.8 H	2.3
Naroff Economic Advisors	1.7 L	4.8	2.4	1.9	1.9	2.1 H	2.1 L	2.4	2.8	3.0	3.3	4.4	5.0	3.9	4.6	86.3	3.3	2.6	2.7
Wells Fargo	1.7 L	4.7 L	2.4	1.8	1.9	2.0	2.2	2.5	2.8	3.0	3.2	4.2	4.9	3.7	4.6	86.3	3.0	1.7	1.4
S&P Global	1.7 L	5.0	2.1	na	1.7 L	1.9	2.2	2.4	2.7	2.9	3.2	na	na	na	4.4	86.1	3.4	2.8	1.6
Cycledata Corp.	1.7 L	4.8	2.0	1.7 L	1.7 L	1.9	2.1 L	2.3 L	2.6	2.8 L	3.1	4.1	4.8	3.8	4.5	86.0	2.9	2.0	2.2
RDQ Economics	1.7 L	4.8	2.2	1.8	1.9	2.1 H	2.2	2.3 L	2.6	2.9	3.1	3.9	4.8	3.7	4.5	87.5	2.6	2.2	2.2
Nat'l Assn. of Realtors	1.7 L	4.8	2.0	1.8	1.8	2.0	2.1 L	2.4	2.7	2.9	3.1	4.0	4.7	na	4.4	na	2.9	2.2	2.5
MUFG Union Bank	1.7 L	4.8	2.3	1.7 L	1.8	1.9	2.1 L	2.4	2.7	2.9	3.2	3.9	4.7	3.8	4.5	86.0	3.0	2.1	3.2 H
Scotiabank Group	1.7 L	4.8	na	na	1.8	na	na	2.5	na	2.9	3.1	na	na	na	na	na	2.5	2.4	0.7
The Northern Trust Company	1.7 L	4.8	2.4	1.9	1.9	2.0	2.2	2.4	2.7	3.0	3.2	4.0	4.7	3.8	4.6	87.1	3.1	2.0	1.9
Fannie Mae	1.7 L	4.8	na	na	2.0 H	2.1 H	2.3 H	2.5	2.8	3.0	3.2	na	na	na	4.6	na	3.2	1.3 L	1.2
PNC Financial Services Corp.	1.7 L	4.8	2.4	na	1.8	2.0	2.2	2.4	2.7	2.8 L	3.1	na	4.7	3.9	4.4	86.6	3.2	2.1	1.6
High Frequency Economics	1.7 L	4.8	na	na	1.7 L	1.9	2.1 L	2.6 H	2.7	2.8 L	3.1	na	na	na	na	na	3.7	1.8	1.8
Oxford Economics	1.7 L	5.0	2.4	na	1.8	2.0	2.3 H	2.4	2.7	2.9	3.2	na	na	na	4.4	85.9	3.7	1.9	1.9
Moody's Capital Markets Group	1.7 L	4.8	2.4	1.9	1.8	2.0	2.2	2.5	2.8	2.9	3.1	4.0	4.7	3.7	4.6	87.3	3.0	2.0	2.1
Comerica Bank	1.7 L	4.8	2.3	na	1.7 L	1.9	2.1 L	2.3 L	2.7	2.9	3.1	na	na	na	4.5	na	3.4	2.0	2.5
Chmura Economics & Analytics	1.7 L	4.8	2.3	1.8	1.8	2.0	2.1 L	2.3 L	2.7	2.8 L	3.1	3.8	na	na	4.5	89.3 H	3.4	2.1	2.6
GLC Financial Economics	1.7 L	4.8	2.1	1.8	1.8	2.0	2.1 L	2.3 L	2.6	2.9	3.1	4.2	4.8	3.7	4.5	85.8	2.9	2.4	2.4
May Consensus	**1.7**	**4.8**	**2.3**	**1.8**	**1.8**	**2.0**	**2.2**	**2.4**	**2.7**	**2.9**	**3.2**	**4.0**	**4.8**	**3.8**	**4.5**	**86.6**	**3.1**	**2.0**	**1.9**
Top 10 Avg.	1.9	4.9	2.4	1.9	1.9	2.1	2.2	2.5	2.8	3.0	3.3	4.2	4.9	3.9	4.6	87.5	3.8	2.4	2.6
Bottom 10 Avg.	1.7	4.7	2.0	1.7	1.7	1.9	2.1	2.3	2.6	2.8	3.1	3.9	4.7	3.7	4.4	86.0	2.5	1.7	1.2
April Consensus	1.7	4.8	2.1	1.8	1.8	2.0	2.1	2.4	2.7	2.9	3.2	4.1	4.8	3.8	4.5	86.4	3.1	2.0	1.9
Number of Forecasts Changed From A Month Ago:																			
Down	2	3	2	4	10	6	6	6	9	14	22	5	4	8	10	7	8	6	11
Same	28	28	10	11	12	12	11	14	14	13	10	10	8	6	10	10	20	19	16
Up	13	5	23	10	16	16	17	23	18	16	9	11	14	7	14	7	15	16	16
Diffusion Index	63 %	53 %	80 %	62 %	58 %	65 %	66 %	70 %	61 %	52 %	34 %	62 %	69 %	48 %	56 %	50 %	58 %	62 %	56 %

Third Quarter 2018

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr. A. Fed's Major Currency $ Index	(Q-Q % Change) (SAAR) B. Real GDP	C. GDP Price Index	D. Cons. Price Index
ACIMA Private Wealth	2.3 H	5.3 H	2.5	2.3 H	2.3 H	2.4 H	2.4	2.6	2.8	2.8 L	3.1	4.0	4.9	3.9	4.5	85.5	3.2	1.4 L	1.0 L
Chase Wealth Management	2.2	5.3 H	2.4	2.3 H	2.2	2.4 H	2.6 H	2.8 H	3.1 H	3.2	3.5	4.4	5.1	4.0	4.8	86.0	2.9	2.1	2.2
Bank of America Merrill Lynch	2.1	na	2.6	na	2.2	na	na	2.7	3.1 H	3.2	3.3	na	na	na	na	na	3.6	1.8	2.0
J.P. Morgan Chase	2.1	na	2.5	na	na	na	na	2.6	2.8	3.0	3.2	na	na	na	na	na	2.5	2.1	2.2
Swiss Re	2.1	5.1	2.3	2.1	2.0	2.1	2.2	2.4 L	2.6 L	2.9	3.3	4.6	5.5	na	4.7	na	2.7	3.3 H	3.4
RBC Capital Markets	2.1	na	na	na	na	na	na	2.6	2.9	3.2	3.5	na	na	na	na	na	2.8	3.0	4.1 H
BNP Paribas Americas	2.1	na	2.3	na	na	na	na	2.6	3.0	3.2	na	na	na	na	na	na	3.5	na	2.3
Barclays	2.1	5.3 H	na	na	na	na	na	2.5	2.7	2.8 L	3.0 L	na	na	na	na	na	3.5	2.3	2.6
Via Nova Investment Mgt.	2.0	5.0	2.7 H	1.9 L	1.9	2.1	2.3	2.5	3.0	3.3	3.5	4.4	4.9	4.2	4.9	87.0	3.1	2.1	2.3
Scotiabank Group	2.0	5.0	na	na	2.1	na	na	2.6	2.8	3.0	3.2	na	na	na	na	na	2.5	2.0	2.4
Moody's Analytics	2.0	5.1	2.4	2.0	1.9	2.0 L	2.4	2.6	3.0	3.4 H	4.1 H	4.9 H	5.8 H	3.9	4.9	na	3.6	2.4	2.4
Goldman Sachs	2.0	na	2.3	na	1.9	na	na	2.5	2.9	3.2	3.4	na	na	na	4.4 L	na	3.0	2.1	2.6
Nomura Securities, Inc.	2.0	5.1	2.6	na	na	na	na	2.8 H	3.0	3.3	na	4.3	4.8	na	na	na	3.4	2.0	2.8
NatWest Markets	2.0	5.1	2.5	2.0	2.1	2.3	2.5	2.4 L	2.6	2.9	3.3	4.2	4.8	3.8	4.6	88.0	3.0	2.0	2.2
BMO Capital Markets	2.0	4.9	2.6	na	2.1	2.2	2.4	2.6	2.9	3.0	3.2	na	na	na	4.6	85.6	2.9	2.0	2.3
Loomis, Sayles & Company	2.0	5.1	2.5	2.2	2.1	2.3	2.4	2.5	2.8	3.0	3.3	4.0	4.8	3.7	4.5	86.2	3.2	2.4	2.3
Action Economics	2.0	5.1	2.2	2.1	2.1	2.1	2.2	2.4 L	2.7	3.0	3.2	4.0	4.7 L	3.8	4.6	85.8	3.4	2.3	2.5
Amherst Pierpont Securities	2.0	5.1	2.6	2.1	2.1	2.3	2.4	2.7	3.0	3.3	3.6	4.4	5.2	4.3 H	4.9	89.0	3.2	2.4	2.7
DePrince & Associates	2.0	5.0	2.4	2.1	2.0	2.2	2.4	2.6	2.9	3.2	3.4	4.4	5.3	4.2	5.0 H	86.6	3.1	2.1	2.2
MUFG Union Bank	2.0	5.0	2.5	1.9 L	2.0	2.1	2.3	2.5	2.8	3.0	3.4	4.0	4.8	3.9	4.6	85.0	3.1	1.7	2.6
Economist Intelligence Unit	1.9	5.0	2.0 L	2.1	2.1	2.1	2.3	2.7	3.0	3.2	3.4	na	na	na	4.8	na	3.2	na	2.3
MacroFin Analytics	1.9	5.0	2.6	2.0	2.1	2.2	2.5	2.7	3.1 H	3.2	3.4	4.2	5.0	4.0	4.7	87.0	2.0 L	2.2	1.4
The Northern Trust Company	1.9	5.1	2.5	2.0	2.1	2.2	2.3	2.6	2.9	3.2	3.5	4.4	5.1	4.1	4.8	86.6	3.4	2.3	2.1
Oxford Economics	1.9	5.1	2.4	na	1.9	2.1	2.3	2.5	2.7	3.0	3.3	na	na	na	4.6	85.6	3.0	1.9	1.8
Grant Thornton/Diane Swonk	1.9	5.0	2.3	2.1	1.8 L	2.2	2.4	2.6	2.9	3.1	3.4	3.6 L	4.9	3.4 L	4.6	88.7	3.3	2.3	1.9
S&P Global	1.9	5.0	2.2	na	1.9	2.1	2.3	2.5	2.8	3.0	3.4	na	na	na	4.4 L	84.6 L	3.9 H	2.5	1.9
High Frequency Economics	1.9	5.0	na	na	2.0	2.1	2.3	2.7	2.8	3.0	3.3	na	na	na	na	na	3.0	2.1	2.1
Regions Financial Corporation	1.9	4.9	2.6	2.1	2.0	2.2	2.4	2.6	2.9	3.1	3.3	4.3	5.0	4.1	4.7	86.6	3.0	2.0	2.2
AIG	1.9	5.0	na	na	1.9	2.2	2.4	2.6	2.9	3.1	3.4	na	4.9	na	4.6	na	3.2	2.1	2.4
Comerica Bank	1.9	5.0	2.5	na	1.9	2.1	2.2 L	2.4 L	2.8	3.0	3.3	na	na	na	4.6	na	2.9	2.0	2.2
Chmura Economics & Analytics	1.9	5.0	2.5	2.1	2.0	2.2	2.3	2.6	2.9	3.0	3.3	4.1	na	na	4.6	89.9 H	3.3	2.2	2.2
Wells Fargo	1.9	4.9	2.5	2.0	2.1	2.2	2.3	2.6	2.9	3.1	3.4	4.3	5.0	3.8	4.7	85.3	2.9	2.0	2.0
Georgia State University	1.9	5.0	na	na	1.8 L	2.1	2.4	2.5	3.0	3.3	3.6	4.4	5.1	na	4.8	na	2.9	2.4	2.0
Daiwa Capital Markets America	1.9	5.1	2.5	1.9 L	2.0	2.2	2.3	2.6	3.0	3.2	3.4	4.1	4.9	na	4.8	87.0	2.3	2.2	2.2
Cycledata Corp.	1.9	5.0	2.1	2.0	1.9	2.0 L	2.2 L	2.5	2.8	3.0	3.3	4.3	5.0	4.0	4.7	86.0	2.9	2.1	2.3
RDQ Economics	1.9	5.0	2.3	2.0	2.0	2.2	2.4	2.5	2.8	3.0	3.2	4.2	5.0	3.8	4.6	88.8	2.5	2.2	2.3
Nat'l Assn. of Realtors	1.9	4.9	2.2	2.0	2.0	2.2	2.3	2.5	2.9	3.1	3.5	4.3	4.9	na	4.5	na	2.6	2.3	2.5
Naroff Economic Advisors	1.9	5.0	2.5	2.1	2.1	2.2	2.3	2.6	2.9	3.2	3.4	4.6	5.3	4.1	4.9	85.0	3.1	2.4	2.7
Fannie Mae	1.9	5.0	na	na	2.3	2.4	2.5	2.6	2.9	3.0	3.2	na	na	na	4.7	na	3.0	1.9	1.9
PNC Financial Services Corp.	1.9	5.0	2.5	na	2.0	2.2	2.3	2.6	2.8	3.0	3.3	na	4.9	3.9	4.5	86.8	3.1	2.0	1.9
Moody's Capital Markets Group	1.9	5.0	2.6	2.1	2.0	2.2	2.3	2.5	2.7	2.9	3.1	4.1	4.7 L	3.6	4.6	88.0	2.7	2.0	2.0
Societe Generale	1.9	5.0	na	na	2.0	na	na	2.6	na	3.0	3.1	na	na	na	na	na	2.4	2.0	1.2
GLC Financial Economics	1.8 L	4.8 L	2.2	2.0	2.0	2.1	2.3	2.5	2.8	3.1	3.2	4.3	5.0	3.7	4.6	85.9	3.4	2.1	2.9
May Consensus	**2.0**	**5.0**	**2.4**	**2.1**	**2.0**	**2.2**	**2.3**	**2.6**	**2.9**	**3.1**	**3.3**	**4.2**	**5.0**	**3.9**	**4.7**	**86.7**	**3.0**	**2.2**	**2.3**
Top 10 Avg.	2.1	5.1	2.6	2.1	2.1	2.3	2.4	2.7	3.0	3.2	3.6	4.5	5.2	4.1	4.8	88.0	3.5	2.5	2.9
Bottom 10 Avg.	1.9	4.9	2.2	2.0	1.9	2.1	2.3	2.5	2.7	2.9	3.1	4.0	4.8	3.7	4.5	85.4	2.5	1.9	1.7
April Consensus	2.0	5.0	2.3	2.0	2.0	2.2	2.3	2.5	2.8	3.1	3.3	4.2	5.0	3.9	4.6	86.4	3.0	2.2	2.2
Number of Forecasts Changed From A Month Ago:																			
Down	2	2	2	4	7	9	6	6	7	9	17	6	5	7	10	6	7	11	11
Same	34	31	16	12	18	11	13	17	16	18	13	12	8	6	10	8	26	21	19
Up	7	3	17	8	13	14	15	20	19	16	11	7	13	8	14	11	10	9	13
Diffusion Index	56 %	51 %	71 %	58 %	58 %	57 %	63 %	66 %	64 %	58 %	43 %	52 %	65 %	52 %	56 %	60 %	53 %	48 %	52 %

Fourth Quarter 2018

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter															Avg. For	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term				Long-Term							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	A.	B.	C.	D.
	Federal Funds Rate	Prime Bank Rate	LIBOR Rate 3-Mo.	Com. Paper 1-Mo.	Treas. Bills 3-Mo.	Treas. Bills 6-Mo.	Treas. Bills 1-Yr.	Treas. Notes 2-Yr.	Treas. Notes 5-Yr.	Treas. Notes 10-Yr.	Treas. Bond 30-Yr.	Aaa Corp. Bond	Baa Corp. Bond	State & Local Bonds	Home Mtg. Rate	Fed's Major Currency $ Index	Real GDP	GDP Price Index	Cons. Price Index
Chase Wealth Management	2.4 H	5.5 H	2.6	2.5 H	2.4 H	2.6 H	2.8 H	3.0 H	3.4 H	3.4	3.7	4.6	5.3	4.2	5.0	85.8	2.8	2.2	2.1
RBC Capital Markets	2.4 H	na	na	na	na	na	na	2.8	3.1	3.3	3.6	na	na	na	na	na	2.8	1.0	0.5 L
Swiss Re	2.4 H	5.4	2.5	2.3	2.2	2.4	2.5	2.6	2.7	2.9	3.4	4.7	5.6	na	4.8	na	3.1	0.6 L	1.7
J.P. Morgan Chase	2.4 H	na	2.7	na	na	na	na	2.8	3.0	3.1	3.2	na	na	na	na	na	2.5	2.1	2.2
Barclays Capital	2.4 H	5.5 H	na	na	na	na	na	2.6	2.7	2.8	3.0	na	na	na	na	na	2.9	2.0	1.9
BNP Paribas Americas	2.4 H	na	2.5	na	na	na	na	2.7	3.1	3.2	na	na	na	na	na	na	3.0	na	2.4
Moody's Analytics	2.4 H	5.5 H	2.7	2.3	2.2	2.3	2.7	2.9	3.3	3.7 H	4.4 H	5.3 H	6.2 H	4.2	5.1	na	3.2	2.9	2.4
ACIMA Private Wealth	2.3	5.3	2.6	2.5 H	2.3	2.4	2.4	2.4 L	2.6 L	2.5 L	2.9 L	4.0	4.9	3.9	4.3 L	84.5	2.5	2.1	1.6
Goldman Sachs & Co.	2.3	na	2.6	na	2.2	na	na	2.6	3.1	3.2	3.5	na	na	na	4.6	na	2.5	1.7	1.8
Scotiabank Group	2.3	5.3	na	na	2.3	na	na	2.7	2.9	3.0	3.2	na	na	na	na	na	2.5	2.0	2.4
Nomura Securities, Inc.	2.3	5.4	2.7	na	na	na	na	3.0 H	3.1	3.3	na	4.3	4.8	na	na	na	3.4 H	2.0	2.5
NatWest Markets	2.2	5.3	2.7	2.3	2.3	2.5	2.7	2.5	2.7	2.9	3.4	4.2	4.9	4.0	4.7	90.0	3.0	2.0	1.8
DePrince & Assoc.	2.2	5.2	2.6	2.4	2.3	2.5	2.7	2.8	3.1	3.3	3.5	4.6	5.7	4.4 H	5.1	87.2	2.9	2.2	2.3
MacroFin Analytics	2.2	5.3	2.8 H	2.3	2.3	2.5	2.7	3.0 H	3.3	3.5	3.7	4.5	5.3	4.3	5.0	87.4	2.2 L	2.2	2.3
BMO Capital Markets	2.2	5.2	2.7	na	2.2	2.4	2.5	2.7	3.0	3.1	3.3	na	na	na	4.7	85.0	2.9	2.1	2.3
Wells Fargo	2.2	5.2	2.6	2.2	2.3	2.4	2.5	2.7	2.9	3.1	3.4	4.3	5.0	3.9	4.7	84.0 L	3.1	2.0	2.0
S&P Global	2.2	5.2	2.4	na	2.1	2.3	2.4	2.7	2.9	3.1	3.5	na	na	na	4.6	84.3	3.1	2.1	2.0
Daiwa Capital Markets America	2.2	5.3	2.8 H	2.2	2.3	2.5	2.6	2.9	3.2	3.4	3.6	4.3	5.1	na	5.1	88.0	2.4	2.3	2.3
RDQ Economics	2.2	5.3	2.6	2.3	2.4 H	2.6 H	2.7	2.7	3.0	3.2	3.4	4.6	5.3	4.1	4.8	90.1	2.4	2.3	2.3
Naroff Economic Advisors	2.2	5.3	2.6	2.3	2.4 H	2.5	2.7	2.8	3.1	3.3	3.6	4.8	5.5	4.3	5.1	84.1	2.6	2.6	2.9
Amherst Pierpont Securities	2.2	5.3	2.8 H	2.3	2.3	2.5	2.7	2.9	3.2	3.5	3.8	4.6	5.5	4.4 H	5.2 H	90.0	3.2	2.5	3.0
MUFG Union Bank	2.2	5.3	2.6	2.2	2.2	2.3	2.6	2.6	2.9	3.1	3.5	4.1	4.9	4.0	4.7	84.0 L	3.3	2.1	3.3 H
Grant Thornton/Diane Swonk	2.2	5.2	2.6	2.4	2.1	2.5	2.7	2.9	3.2	3.3	3.7	3.9 L	5.1	3.5 L	4.9	90.3 H	3.2	2.3	1.1
The Northern Trust Company	2.2	5.3	2.6	2.3	2.3	2.4	2.5	2.7	3.1	3.4	3.7	4.7	5.5	4.4	5.0	86.1	3.4 H	2.5	2.3
Oxford Economics	2.2	5.2	2.6	na	2.0	2.3	2.4	2.6	2.8	3.1	3.5	na	na	na	4.7	84.9	3.0	1.9	2.0
High Frequency Economics	2.2	5.3	na	na	2.2	2.4	2.6	2.8	3.0	3.1	3.4	na	na	na	na	na	2.8	2.5	2.5
Regions Financial Corporation	2.2	5.2	2.7	2.2	2.2	2.3	2.4	2.7	3.0	3.2	3.5	4.4	5.1	4.2	4.8	86.8	3.2	1.9	2.1
Economist Intelligence Unit	2.2	5.2	2.2	2.3	2.3	2.3	2.5	2.9	3.1	3.3	3.6	na	na	na	4.9	na	2.2	na	2.2
Chmura Economics & Analytics	2.2	5.3	2.8	2.3	2.2	2.4	2.6	2.8	3.0	3.2	3.6	4.3	na	na	4.8	89.7	3.1	3.1 H	2.5
Societe Generale	2.2	5.3	na	na	2.1	na	na	2.6	na	3.0	3.1	na	na	na	na	na	2.3	2.0	2.0
Comerica Bank	2.1	5.2	2.6	na	2.1	2.2	2.4	2.6	2.9	3.1	3.4	na	na	na	4.8	na	2.6	2.0	2.1
Action Economics	2.1	5.3	2.4	2.2	2.2	2.3	2.4	2.6	2.8	3.0	3.2	4.0	4.8	3.8	4.6	85.6	3.2	2.2	2.1
Loomis, Sayles & Company	2.1	5.2	2.7	2.3	2.3	2.4	2.5	2.6	2.8	3.0	3.3	4.0	4.8	3.7	4.5	86.4	3.2	2.4	2.1
Bank of America Merrill Lynch	2.1	na	2.6	na	2.3	na	na	2.8	3.2	3.3	3.3	na	na	na	na	na	3.1	1.8	2.3
GLC Financial Economics	2.1	5.1	2.4	2.2	2.2	2.3	2.5	2.7	3.1	3.2	3.3	4.5	5.1	3.9	4.8	86.1	2.7	1.9	2.8
Via Nova Investment Mgt.	2.1	5.1	2.8 H	2.0 L	2.0	2.1	2.4	2.6	3.1	3.3	3.6	4.5	4.9	4.3	4.9	87.0	3.0	2.2	2.3
AIG	2.0	5.1	na	na	1.9	2.3	2.5	2.7	3.0	3.2	3.5	na	5.0	na	4.7	na	3.1	2.1	1.9
Nat'l Assn. of Realtors	2.0	5.0 L	2.3	2.1	2.1	2.3	2.5	2.6	3.0	3.2	3.6	4.4	5.0	na	4.7	na	2.7	2.3	2.4
Georgia State University	1.9 L	5.0 L	na	na	1.8 L	2.1	2.4	2.6	3.2	3.5	3.9	4.7	5.4	na	5.0	na	2.4	2.4	1.9
Moody's Capital Markets Group	1.9 L	5.0 L	2.6	2.2	2.1	2.2	2.4	2.5	2.7	2.9	3.1	3.9 L	4.7 L	3.6	4.6	88.5	2.4	1.9	1.5
Fannie Mae	1.9 L	5.0 L	na	na	2.4 H	2.5	2.6	2.7	3.0	3.1	3.2	na	na	na	4.7	na	2.7	2.1	1.2
PNC Financial Services Corp.	1.9 L	5.0 L	2.6	na	2.1	2.3	2.4	2.7	2.9	3.1	3.4	na	5.0	4.0	4.6	86.8	3.3	2.0	2.0
Cycledata Corp.	1.9 L	5.0 L	2.1 L	2.0 L	1.9	2.0 L	2.2 L	2.5	2.8	3.0	3.3	4.3	5.0	4.0	4.7	86.0	2.9	2.2	2.3
May Consensus	**2.2**	**5.2**	**2.6**	**2.3**	**2.2**	**2.4**	**2.5**	**2.7**	**3.0**	**3.2**	**3.5**	**4.4**	**5.2**	**4.0**	**4.8**	**86.7**	**2.9**	**2.1**	**2.1**
Top 10 Avg.	2.3	5.4	2.7	2.4	2.3	2.5	2.7	2.9	3.2	3.4	3.8	4.7	5.5	4.3	5.1	88.8	3.3	2.6	2.7
Bottom 10 Avg.	2.0	5.1	2.4	2.1	2.0	2.2	2.4	2.5	2.7	2.9	3.1	4.1	4.9	3.8	4.6	84.8	2.4	1.7	1.5
April Consensus	2.2	5.2	2.5	2.3	2.2	2.3	2.5	2.7	2.9	3.2	3.5	4.4	5.1	4.1	4.8	86.5	2.8	2.1	2.1
Number of Forecasts Changed From A Month Ago:																			
Down	1	2	4	5	7	7	8	7	8	8	14	4	5	8	9	8	8	9	9
Same	36	31	15	12	21	17	13	19	18	23	15	11	10	8	9	10	22	24	23
Up	5	2	16	8	10	10	13	17	16	12	12	10	11	6	16	7	13	8	11
Diffusion Index	55 %	50 %	67 %	56 %	54 %	54 %	57 %	62 %	60 %	55 %	48 %	62 %	62 %	45 %	60 %	48 %	56 %	49 %	52 %

First Quarter 2019

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter															Avg. For	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term				Long-Term				Qtr.			
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Moody's Analytics	3.0 H	6.1 H	3.3 H	3.0 H	2.8 H	2.9 H	3.1 H	3.3 H	3.6	3.9 H	4.5 H	5.4 H	6.3 H	4.3	5.3	na	2.7	2.9 H	2.5
Chase Wealth Management	2.7	5.8	2.9	2.8	2.7	2.9 H	3.1 H	3.3 H	3.6	3.7	4.0	4.9	5.6	4.5	5.3	85.8	1.7	2.1	2.2
RBC Capital Markets	2.6	na	na	na	na	na	na	3.0	3.3	3.5	3.7	na	na	na	na	na	2.4	2.5	1.4
J.P. Morgan Chase	2.6	na	3.0	na	na	na	na	3.0	3.1	3.2	3.3	na	na	na	na	na	2.3	2.2	2.3
BNP Paribas Americas	2.6	na	2.6	na	na	na	na	2.8	3.1	3.3	na	na	na	na	na	na	1.1 L	na	2.0
Barclays	2.6	5.8	na	na	na	na	na	2.7	2.7	2.8	3.0	na	na	na	na	na	2.5	2.2	2.2
MacroFin Analytics	2.6	5.7	3.2	2.7	2.7	2.9 H	3.1 H	3.3 H	3.7 H	3.9 H	4.0	4.8	5.6	4.6	5.4 H	88.0	2.3	2.2	2.3
Nomura Securities, Inc.	2.5	5.6	2.8	na	na	na	na	3.0	3.1	3.3	na	4.3	4.8	na	na	na	2.4	1.9	2.3
Goldman Sachs & Co.	2.5	na	2.8	na	2.4	na	na	2.8	3.2	3.3	3.5	na	na	na	4.7	na	1.9	2.4	2.3
Naroff Economic Advisors	2.5	5.5	2.8	2.6	2.6	2.8	2.9	3.1	3.3	3.5	3.9	5.0	5.8	4.6	5.3	83.0	3.2 H	2.4	2.5
Swiss Re	2.5	5.5	2.6	2.4	2.4	2.5	2.6	2.8	2.7	2.9	3.5	4.7	5.6	na	4.8	na	1.9	1.9	3.3 H
NatWest Markets	2.5	5.6	2.9	2.5	2.6	2.8	3.0	2.7	2.9	3.0	3.5	4.3	5.0	4.0	4.8	89.0	2.8	2.3	2.2
DePrince & Assoc.	2.5	5.5	2.8	2.6	2.5	2.7	2.8	3.0	3.2	3.4	3.7	4.8	5.8	4.5	5.2	87.7	2.8	2.2	2.4
S&P Global	2.5	5.3	2.7	na	2.3	2.6	2.7	2.8	3.0	3.2	3.5	na	na	na	4.7	84.0	2.3	2.1	1.9
BMO Capital Markets	2.5	5.4	2.9	na	2.4	2.6	2.7	2.9	3.1	3.2	3.4	na	na	na	4.8	84.5	2.7	2.2	2.4
Amherst Pierpont Securities	2.5	5.6	2.9	2.5	2.5	2.7	2.9	3.1	3.4	3.7	4.1	4.9	5.8	4.6	5.4 H	90.5	2.6	2.6	3.2
MUFG Union Bank	2.5	5.5	2.8	2.4	2.4	2.5	2.9	2.8	3.0	3.2	3.5	4.2	5.0	4.1	4.8	83.0	2.7	2.1	3.0
The Northern Trust Company	2.4	5.6	2.9	2.5	2.6	2.7	2.8	3.0	3.3	3.6	3.9	5.0	5.9	4.6	5.2	85.9	3.2 H	2.4	2.2
Oxford Economics	2.4	5.2 L	2.7	na	2.3	2.5	2.6	2.8	2.9	3.2	3.6	na	na	na	4.8	84.6	2.1	1.9	2.1
High Frequency Economics	2.4	5.5	na	na	2.5	2.6	2.8	2.9	3.1	3.3	3.5	na	na	na	na	na	2.6	2.7	2.7
Chmura Economics & Analytics	2.4	5.5	3.0	2.5	2.4	2.7	2.8	3.0	3.2	3.4	3.8	4.5	na	na	4.9	89.3	3.1	2.2	2.6
RDQ Economics	2.4	5.5	2.8	2.5	2.6	2.8	2.9	2.9	3.2	3.4	3.6	4.9	5.5	4.3	5.0	90.6	2.3	2.3	2.3
Daiwa Capital Markets America	2.4	5.6	2.9	2.4	2.5	2.7	2.8	3.3 H	3.6	3.7	3.9	4.7	5.4	na	5.4 H	88.0	2.5	2.4	2.4
Wells Fargo	2.4	5.4	2.7	2.3	2.5	2.6	2.7	3.0	3.2	3.3	3.6	4.4	5.2	4.0	4.8	82.5 L	2.6	2.3	2.6
Grant Thornton/Diane Swonk	2.4	5.4	2.9	2.6	2.2	2.7	2.9	3.1	3.3	3.4	3.8	4.1	5.2	3.6	4.9	91.2 H	2.9	2.6	1.2 L
Bank of America Merrill Lynch	2.4	na	2.9	na	2.5	na	na	2.9	3.2	3.3	3.4	na	na	na	na	na	1.9	1.8 L	2.0
Regions Financial Corporation	2.3	5.4	2.8	2.3	2.3	2.5	2.5	2.8	3.1	3.3	3.6	4.6	5.3	3.3 L	4.9	86.6	2.7	2.1	2.1
Via Nova Investment Mgt.	2.3	5.3	2.9	2.2	2.2	2.4	2.6	2.8	3.3	3.6	3.8	4.7	5.2	4.7 H	5.2	88.0	2.8	2.2	2.3
GLC Financial Economics	2.3	5.3	2.6	2.4	2.4	2.5	2.7	2.8	3.3	3.5	3.6	4.8	5.5	4.2	5.1	86.6	2.8	1.9	2.9
ACIMA Private Wealth	2.3	5.3	2.7	2.6	2.2	2.3	2.2 L	2.3 L	2.2 L	2.2 L	2.7 L	4.0 L	5.0	3.8	4.3 L	83.5	1.9	2.1	1.3
Scotiabank Group	2.3	5.3	na	na	2.3	na	na	2.8	3.0	3.1	3.3	na	na	na	na	na	2.4	2.2	2.4
Action Economics	2.2	5.3	2.6	2.3	2.4	2.5	2.7	2.8	2.9	3.1	3.3	4.1	4.9	3.8	4.7	85.4	2.8	1.9	2.5
Loomis, Sayles & Company	2.2	5.3	2.7	2.3	2.3	2.4	2.5	2.6	2.9	3.2	3.4	4.2	4.9	3.9	4.7	86.5	3.1	2.6	2.2
Nat'l Assn. of Realtors	2.2	5.2 L	2.5	2.3	2.3	2.5	2.6	2.7	3.1	3.3	3.7	4.5	5.2	na	4.8	na	2.6	2.3	2.3
Economist Intelligence Unit	2.2	5.2 L	2.3	2.3	2.3	2.4	2.6	2.9	3.2	3.4	3.6	na	na	na	5.0	na	1.6	na	2.3
Fannie Mae	2.2	5.3	na	na	2.6	2.6	2.7	2.7	3.0	3.1	3.2	na	na	na	4.7	na	2.8	2.5	1.2 L
Moody's Capital Markets Group	2.2	5.3	2.8	2.4	2.2	2.4	2.4	2.5	2.7	2.9	3.0	4.2	4.7 L	3.5	4.6	89.4	2.1	1.9	1.8
Comerica Bank	2.2	5.3	2.6	na	2.1	2.2 L	2.4	2.6	2.9	3.1	3.4	na	na	na	4.8	na	2.5	2.0	2.1
Georgia State University	2.2	5.3	na	na	2.0 L	2.4	2.7	2.9	3.3	3.6	4.0	4.8	5.5	na	5.1	na	2.4	2.5	2.1
Societe Generale	2.2	5.3	na	na	2.2	na	na	2.5	na	3.0	3.1	na	na	na	na	na	1.7	2.0	1.9
PNC Financial Services Corp.	2.2	5.3	2.6	na	2.3	2.4	2.5	2.8	3.0	3.2	3.5	na	5.1	4.0	4.7	86.7	3.0	2.1	2.2
Cycledata Corp.	2.1	5.2 L	2.1 L	2.0 L	2.1	2.2 L	2.4	2.6	3.0	3.2	3.4	4.4	5.1	4.1	4.8	86.0	2.7	2.2	2.3
AIG	2.0 L	5.3	na	na	2.1	2.6	2.8	2.9	3.1	3.3	3.7	na	5.0	na	4.8	na	2.6	2.2	1.3
May Consensus	**2.4**	**5.4**	**2.8**	**2.5**	**2.4**	**2.6**	**2.7**	**2.9**	**3.1**	**3.3**	**3.6**	**4.6**	**5.3**	**4.1**	**4.9**	**86.7**	**2.5**	**2.2**	**2.2**
Top 10 Avg.	2.6	5.7	3.0	2.6	2.6	2.8	3.0	3.1	3.4	3.6	4.0	4.9	5.7	4.5	5.3	89.2	3.0	2.6	2.8
Bottom 10 Avg.	2.1	5.2	2.5	2.3	2.2	2.3	2.5	2.6	2.8	2.9	3.1	4.2	4.9	3.8	4.7	84.2	1.8	1.9	1.6
April Consensus	2.4	5.4	2.7	2.5	2.3	2.5	2.7	2.8	3.1	3.3	3.6	4.6	5.3	4.2	4.9	86.5	2.5	2.2	2.2
Number of Forecasts Changed From A Month Ago:																			
Down	2	3	2	4	6	7	6	4	7	7	11	5	6	7	8	9	9	8	6
Same	35	31	19	14	21	16	14	19	17	19	17	10	9	7	10	10	25	27	28
Up	6	2	13	7	10	11	14	18	16	15	11	11	12	6	16	5	9	6	9
Diffusion Index	55 %	49 %	66 %	56 %	55 %	56 %	62 %	67 %	61 %	60 %	50 %	62 %	61 %	48 %	62 %	42 %	50 %	48 %	53 %

Second Quarter 2019

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter															Avg. For	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term				Long-Term				Qtr.			
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Moody's Analytics	3.4 H	6.5 H	3.7 H	3.4	3.1 H	3.2 H	3.4 H	3.6 H	3.8	3.9	4.6 H	5.5 H	6.4 H	4.3	5.3	na	2.2	3.0 H	2.7
Chase Wealth Management	2.9	6.0	3.1	3.1	2.9	3.1	3.3	3.5	3.9 H	3.9	4.2	5.1	5.8	4.7	5.5	85.9	2.3	2.0	2.3
RBC Capital Markets	2.9	na	na	na	na	na	na	3.3	3.5	3.6	3.8	na	na	na	na	na	3.4 H	1.7	2.2
J.P. Morgan Chase	2.9	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.0	2.2	2.3
Barclays Capital	2.9	6.0	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.4	2.1	2.0
MacroFin Analytics	2.8	5.9	3.5	2.9	3.0	3.1	3.4 H	3.6 H	3.9 H	4.1 H	4.3	5.1	5.9	4.9 H	5.6 H	88.4	2.0	2.3	2.2
Goldman Sachs & Co.	2.8	na	3.1	na	2.7	na	na	3.0	3.3	3.4	3.5	na	na	na	4.8	na	1.9	2.2	2.2
NatWest Markets	2.7	5.8	3.1	2.8	2.8	3.0	3.2	2.8	2.9	3.0	3.5	4.4	5.1	4.1	4.9	88.0	2.7	1.7	0.7
Naroff Economic Advisors	2.7	5.8	3.0	3.7 H	2.9	3.1	3.2	3.3	3.5	3.7	4.1	5.2	5.9	4.8	5.5	82.0	2.6	2.5	2.7
BMO Capital Markets	2.7	5.7	3.0	na	2.6	2.7	2.9	3.0	3.2	3.3	3.5	na	na	na	4.9	84.0	2.2	1.8	1.8
S&P Global	2.7	5.5	3.0	na	2.6	2.9	2.9	3.0	3.1	3.3	3.6	na	na	na	4.9	83.9	2.0	2.1	2.0
Amherst Pierpont Securities	2.7	5.8	3.2	2.8	2.8	2.9	3.1	3.3	3.6	3.9	4.3	5.1	6.0	4.8	5.6 H	91.0	2.8	2.5	3.3 H
RDQ Economics	2.7	5.8	3.1	2.8	2.8	3.0	3.1	3.1	3.4	3.6	3.8	5.2	5.8	4.6	5.3	90.8	2.2	2.3	2.3
DePrince & Associates	2.7	5.7	3.1	2.9	2.8	2.9	3.1	3.2	3.4	3.6	3.8	4.9	5.8	4.6	5.4	88.2	2.7	2.3	2.4
Daiwa Capital Markets America	2.7	5.8	3.2	2.7	2.8	3.0	3.1	3.3	3.6	3.7	3.9	4.7	5.4	na	5.4	88.0	2.5	2.4	2.4
MUFG Union Bank	2.7	5.8	3.0	2.7	2.7	2.8	3.2	3.0	3.1	3.3	3.5	4.3	5.1	4.2	4.9	82.0	2.9	2.1	3.0
Oxford Economics	2.7	5.4	3.0	na	2.6	2.8	2.9	3.0	3.1	3.3	3.6	na	na	na	5.0	84.8	2.3	1.9	2.0
High Frequency Economics	2.7	5.8	na	na	2.7	2.9	3.0	3.0	3.2	3.4	3.6	na	na	na	na	na	2.5	2.7	2.7
Chmura Economics & Analytics	2.7	5.8	3.2	2.8	2.7	2.9	3.1	3.2	3.4	3.5	4.0	4.7	na	na	5.1	88.8	3.3	2.2	2.4
Swiss Re	2.6	5.6	2.8	2.6	2.5	2.6	2.7	2.9	2.8	2.9	3.6	4.7	5.6	na	4.8	na	1.8	1.6 L	0.3 L
Grant Thornton/Diane Swonk	2.6	5.6	3.1	2.9	2.4	2.9	3.0	3.2	3.3	3.5	3.9	4.2	5.3	3.6	5.0	92.4 H	2.6	2.6	2.1
Bank of America Merrill Lynch	2.6	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	1.9	1.9	2.3
The Northern Trust Company	2.6	5.8	3.1	2.7	2.8	2.9	3.0	3.2	3.5	3.8	4.0	5.3	6.1	4.8	5.4	86.0	2.9	2.6	2.3
BNP Paribas Americas	2.6	na	2.7	na	na	na	na	2.8	3.1	3.3	na	na	na	na	na	na	2.0	na	1.5
Regions Financial Corporation	2.5	5.6	2.8	2.4	2.4	2.6	2.6	2.9	3.2	3.4	3.7	4.7	5.4	4.5	5.0	86.3	2.2	2.0	2.1
Nomura Securities, Inc.	2.5	5.6	2.8	na	na	na	na	3.0	3.0	3.1	na	4.2	4.7	na	na	na	2.1	2.0	1.5
Nat'l Assn. of Realtors	2.5	5.5	2.8	2.6	2.6	2.7	2.8	2.9	3.2	3.5	3.9	4.6	5.3	na	4.9	na	2.5	2.2	2.3
Via Nova Investment Mgt.	2.5	5.5	3.0	2.4	2.4	2.6	2.8	3.0	3.5	3.8	4.0	4.9	5.4	4.9 H	5.4	88.0	2.6	2.2	2.3
Economist Intelligence Unit	2.5	5.5	2.6	2.6	2.6	2.6	2.7	3.1	3.3	3.5	3.8	na	na	na	5.1	na	3.2	na	2.3
Scotiabank Group	2.5	5.5	na	na	2.6	na	na	3.0	3.0	3.1	3.3	na	na	na	na	na	2.3	2.2	2.4
Wells Fargo	2.5	5.5	2.9	2.4	2.6	2.7	2.8	3.1	3.2	3.4	3.7	4.5	5.3	4.1	4.9	81.0 L	3.1	2.3	2.4
GLC Financial Economics	2.5	5.5	2.7	2.5	2.5	2.6	2.7	2.9	3.4	3.6	3.8	5.1	5.8	4.3	5.3	86.8	3.2	1.6	2.4
Action Economics	2.5	5.6	2.7	2.6	2.6	2.7	2.9	2.9	3.0	3.1	3.3	4.1	4.9	3.8	4.8	85.2	3.0	2.6	2.5
Comerica Bank	2.4	5.5	2.8	na	2.3	2.4	2.6	2.8	3.1	3.3	3.7	na	na	na	5.0	na	2.5	2.0	2.0
Loomis, Sayles & Company	2.4	5.5	2.8	2.4	2.4	2.5	2.6	2.7	3.0	3.3	3.5	4.3	5.0	4.0	4.8	86.6	2.7	2.5	2.2
PNC Financial Services Corp.	2.4	5.5	2.8	na	2.4	2.6	2.7	2.9	3.1	3.3	3.6	na	5.2	4.0	4.8	86.7	2.6	2.1	2.2
Moody's Capital Markets Group	2.4	5.5	3.1	2.5	2.4	2.5	2.5	2.5	2.6	2.9	3.0	4.2	4.7 L	3.5 L	4.6	89.7	2.2	1.9	1.6
Fannie Mae	2.4	5.5	na	na	2.6	2.7	2.7	2.9	3.1	3.1	3.2	na	na	na	4.7	na	2.6	2.5	2.1
Georgia State University	2.4	5.5	na	na	2.1	2.6	2.9	3.1	3.4	3.7	4.1	4.8	5.6	na	5.2	na	2.3	2.3	2.2
AIG	2.3	5.6	na	na	2.4	2.7	2.8	3.0	3.1	3.3	3.8	na	5.2	na	4.9	na	2.2	2.4	1.5
Societe Generale	2.2	5.3	na	na	2.2	na	na	2.4	na	2.8	2.9	na	na	na	na	na	0.8 L	2.0	2.0
Cycledata Corp.	2.1	5.2	2.1 L	2.0 L	2.1	2.2	2.4	2.6	3.0	3.2	3.4	4.4	5.1	4.1	4.8	86.0	2.7	2.2	2.3
ACIMA Private Wealth	2.0 L	5.0 L	2.5	2.5	1.8 L	2.0 L	1.9 L	2.0 L	2.0 L	2.0 L	2.6 L	3.9 L	5.0	3.7	4.2 L	83.0	1.8	2.2	2.1
May Consensus	**2.6**	**5.6**	**2.9**	**2.7**	**2.6**	**2.7**	**2.9**	**3.0**	**3.2**	**3.4**	**3.7**	**4.7**	**5.4**	**4.3**	**5.0**	**86.5**	**2.4**	**2.2**	**2.2**
Top 10 Avg.	2.9	5.9	3.2	3.0	2.9	3.0	3.2	3.3	3.6	3.8	4.1	5.1	5.9	4.7	5.4	89.3	3.1	2.6	2.7
Bottom 10 Avg.	2.3	5.4	2.6	2.4	2.2	2.4	2.5	2.6	2.8	2.9	3.2	4.2	5.0	3.9	4.7	83.8	1.8	1.8	1.5
April Consensus	2.6	5.6	2.9	2.7	2.5	2.7	2.8	2.9	3.2	3.4	3.7	4.7	5.4	4.3	5.0	86.6	2.4	2.1	2.2
Number of Forecasts Changed From A Month Ago:																			
Down	2	4	3	5	6	5	6	8	7	8	10	4	6	7	8	9	6	7	10
Same	33	29	20	13	21	19	14	16	16	17	17	12	8	8	11	11	22	24	26
Up	8	3	10	7	10	10	14	16	16	15	11	10	13	7	15	4	15	10	7
Diffusion Index	57 %	49 %	61 %	54 %	55 %	57 %	62 %	60 %	62 %	59 %	51 %	62 %	63 %	50 %	60 %	40 %	60 %	54 %	47 %

Third Quarter 2019

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter															Avg. For	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term				Long-Term				Qtr.			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	A.	B.	C.	D.
	Federal Funds Rate	Prime Bank Rate	LIBOR Rate 3-Mo.	Com. Paper 1-Mo.	Treas. Bills 3-Mo.	Treas. Bills 6-Mo.	Treas. Bills 1-Yr.	Treas. Notes 2-Yr.	Treas. Notes 5-Yr.	Treas. Notes 10-Yr.	Treas. Bond 30-Yr.	Aaa Corp. Bond	Baa Corp. Bond	State & Local Bonds	Home Mtg. Rate	Fed's Major Currency $ Index	Real GDP	GDP Price Index	Cons. Price Index
Moody's Analytics	3.7 H	6.9 H	4.0 H	3.7	3.4 H	3.5 H	3.7 H	3.8 H	3.9	4.0	4.7 H	5.5 H	6.5 H	4.4	5.4	na	1.8	2.6	2.7
Chase Wealth Management	3.2	6.3	3.4	3.3	3.2	3.4	3.6	3.8 H	4.1 H	4.2 H	4.5	5.4	6.1	5.0	5.8 H	86.0	2.1	2.1	2.2
J.P. Morgan Chase	3.1	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	1.8	2.3	2.4
RBC Capital Markets	3.1	na	na	na	na	na	na	3.4	3.6	3.7	3.8	na	na	na	na	na	3.4 H	3.1	3.5 H
Barclays Capital	3.1	6.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.0	2.3	2.2
Goldman Sachs & Co.	3.0	na	3.3	na	2.9	na	na	3.2	3.4	3.5	3.6	na	na	na	4.9	na	1.7	2.0	2.0
MUFG Union Bank	3.0	6.0	3.2	2.9	3.0	3.1	3.4	3.2	3.2	3.4	3.6	4.4	5.2	4.3	5.0	81.0	2.8	2.1	2.8
Amherst Pierpont Securities	3.0	6.1	3.4	3.0	3.0	3.2	3.3	3.4	3.8	4.0	4.4	5.3	6.2	4.9	5.8 H	91.5	2.7	2.6	3.3
MacroFin Analytics	2.9	6.0	3.6	3.0	3.1	3.2	3.5	3.7	4.0	4.2 H	4.4	5.2	6.0	5.0	5.7	89.0	2.0	2.3	2.2
Oxford Economics	2.9	5.6	3.1	na	2.8	2.9	3.1	3.1	3.2	3.3	3.7	na	na	na	5.1	84.9	1.9	1.9	2.0
High Frequency Economics	2.9	6.0	na	na	3.0	3.1	3.2	3.1	3.3	3.5	3.7	na	na	na	na	na	2.1	2.8	2.8
Chmura Economics & Analytics	2.9	6.0	3.5	3.1	2.9	3.1	3.3	3.4	3.6	3.7	4.1	4.8	na	na	5.2	88.3	3.1	2.3	2.3
Naroff Economic Advisors	2.9	6.0	3.2	4.0 H	3.2	3.3	3.4	3.6	3.7	4.0	4.3	5.5	6.1	4.9	5.7	83.5	2.2	2.3	2.3
RDQ Economics	2.9	6.0	3.3	3.0	3.0	3.1	3.2	3.3	3.6	3.8	4.0	5.5	6.1	4.8	5.5	91.3	2.3	2.4	2.4
Daiwa Capital Markets America	2.9	6.0	3.3	2.9	3.0	3.2	3.3	3.5	3.8	3.8	4.1	4.9	5.6	na	5.6	88.0	2.3	2.5	2.5
NatWest Markets	2.9	6.0	3.2	2.9	2.9	3.1	3.2	2.9	3.0	3.1	3.5	4.5	5.2	4.0	4.9	88.0	2.6	2.0	1.3 L
S&P Global	2.9	5.6	3.1	na	2.7	2.9	3.0	3.0	3.2	3.4	3.7	na	na	na	5.0	83.7	2.3	2.1	1.9
BMO Capital Markets	2.9	5.9	3.1	na	2.7	2.8	2.9	3.1	3.3	3.4	3.6	na	na	na	5.1	83.6	2.0	1.9	2.0
Bank of America Merrill Lynch	2.9	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	1.9	1.9	2.4
Swiss Re	2.9	5.9	3.0	2.8	2.7	2.9	3.0	3.1	2.9	3.0	3.7	4.7	5.6	na	4.8	na	1.7	3.4 H	3.5 H
DePrince & Associates	2.9	5.9	3.3	3.1	2.9	3.1	3.2	3.4	3.5	3.7	3.9	5.2	6.0	4.8	5.5	88.5	2.5	2.2	2.4
Grant Thornton/Diane Swonk	2.8	5.8	3.3	3.1	2.5	3.0	3.2	3.3	3.4	3.5	4.0	4.4	5.4	3.7	5.1	93.2 H	2.5	2.6	2.2
Via Nova Investment Mgt.	2.8	5.8	3.2	2.7	2.7	2.8	3.1	3.3	3.8	4.0	4.3	5.2	5.6	5.2 H	5.6	88.0	2.5	2.2	2.3
Nomura Securities, Inc.	2.8	5.9	2.9	na	na	na	na	3.0	3.0	3.0	na	4.0	4.6	na	na	na	2.1	2.0	2.5
Action Economics	2.7	5.8	2.9	2.8	2.9	2.9	3.0	3.1	3.1	3.2	3.4	4.2	4.9	3.9	4.8	85.0	3.0	2.3	2.5
Wells Fargo	2.7	5.7	2.9	2.6	2.7	2.8	2.8	3.2	3.3	3.5	3.8	4.6	5.4	4.2	5.0	79.5 L	2.9	2.4	2.9
Economist Intelligence Unit	2.7	5.7	2.7	2.8	2.7	2.8	2.9	3.2	3.4	3.6	3.9	na	na	na	5.2	na	2.2	na	2.3
The Northern Trust Company	2.7	5.8	3.1	2.8	2.8	2.9	3.0	3.2	3.6	3.9	4.2	5.4	6.2	4.9	5.5	86.1	2.6	2.5	2.4
Comerica Bank	2.7	5.8	3.0	na	2.5	2.7	2.8	3.0	3.4	3.6	3.9	na	na	na	5.2	na	2.4	2.0	2.0
Loomis, Sayles & Company	2.6	5.7	3.0	2.7	2.6	2.7	2.7	2.7	3.0	3.3	3.5	4.3	5.0	4.0	4.8	86.6	2.5	2.5	2.2
BNP Paribas Americas	2.6	na	2.7	na	na	na	na	2.7	3.0	3.2	na	na	na	na	na	na	1.2	na	2.4
Regions Financial Corporation	2.6	5.6	2.9	2.6	2.5	2.7	2.7	2.9	3.2	3.4	3.8	4.8	5.5	4.5	5.0	86.1	2.0	2.1	2.0
GLC Financial Economics	2.6	5.6	2.8	2.6	2.6	2.7	2.7	2.9	3.5	3.8	3.9	5.3	6.1	4.6	5.5	86.9	2.8	1.8 L	2.5
AIG	2.5	5.7	na	na	2.5	2.8	2.9	3.0	3.2	3.4	3.8	na	5.3	na	4.9	na	2.1	2.5	1.5
PNC Financial Services Corp.	2.5	5.5	2.8	na	2.5	2.7	2.8	3.0	3.2	3.3	3.6	na	5.3	4.0	4.9	86.7	2.3	2.2	2.2
Nat'l Assn. of Realtors	2.5	5.5	2.8	2.6	2.6	2.7	2.8	3.0	3.3	3.6	4.0	4.7	5.4	na	5.0	na	2.5	2.2	2.3
Scotiabank Group	2.5	5.5	na	na	2.6	na	na	3.0	3.1	3.2	3.4	na	na	na	na	na	2.1	2.2	2.4
Georgia State University	2.4	5.5	na	na	2.2	2.6	2.9	3.1	3.5	3.9	4.4	5.1	5.8	na	5.3	na	2.3	2.1	2.2
Moody's Capital Markets Group	2.4	5.5	3.1	2.5	2.4	2.4	2.4	2.3	2.5	2.8	2.9	4.2	4.6 L	3.4 L	4.5	89.8	2.1	2.0	1.8
Fannie Mae	2.4	5.5	na	na	2.7	2.7	2.8	2.9	3.1	3.1	3.3	na	na	na	4.7	na	2.3	2.4	2.1
Societe Generale	2.2	5.3	na	na	2.2	na	na	2.3	na	2.5	2.7	na	na	na	na	na	-1.0 L	2.0	2.0
Cycledata Corp.	2.1	5.2	2.1 L	2.0 L	2.1	2.2	2.4	2.6	3.0	3.2	3.4	4.4	5.1	4.1	4.8	86.0	2.7	2.2	2.3
ACIMA Private Wealth	1.9 L	4.9 L	2.5	2.5	1.7 L	1.9 L	1.9 L	2.0 L	2.0 L	1.9 L	2.5 L	3.9 L	5.0	3.7	3.3 L	84.0	1.8	2.0	1.9
May Consensus	**2.8**	**5.8**	**3.1**	**2.9**	**2.7**	**2.9**	**3.0**	**3.1**	**3.3**	**3.5**	**3.8**	**4.8**	**5.5**	**4.4**	**5.1**	**86.6**	**2.2**	**2.3**	**2.3**
Top 10 Avg.	3.1	6.1	3.4	3.2	3.1	3.2	3.4	3.5	3.8	4.0	4.3	5.3	6.1	4.9	5.6	89.6	2.9	2.7	2.9
Bottom 10 Avg.	2.3	5.4	2.7	2.5	2.3	2.5	2.6	2.6	2.9	2.9	3.2	4.3	5.0	3.9	4.6	83.7	1.5	2.0	1.8
April Consensus	2.7	5.8	3.1	2.9	2.7	2.9	3.0	3.0	3.3	3.4	3.8	4.8	5.5	4.4	5.2	86.7	2.1	2.2	2.3
Number of Forecasts Changed From A Month Ago:																			
Down	2	4	6	4	5	3	6	3	6	7	10	4	4	7	9	8	3	5	5
Same	32	31	19	15	21	20	16	22	19	21	19	14	12	9	14	13	31	28	29
Up	9	2	8	6	11	11	12	15	14	12	9	8	11	5	11	3	9	8	9
Diffusion Index	58 %	47 %	53 %	54 %	58 %	62 %	59 %	65 %	60 %	56 %	49 %	58 %	63 %	45 %	53 %	40 %	57 %	54 %	55 %

International Interest Rate And Foreign Exchange Rate Forecasts

United States

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			Fed's Major Currency $ Index		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	2.75	2.75	na	na	na	na
BMO Capital Markets	na	na	na	2.95	3.05	3.25	85.9	85.2	84.2
IHSMarkit	na	na	na	3.04	3.20	3.44	na	na	na
ING Financial Markets	2.45	2.65	3.00	3.20	3.40	3.20	91.7	91.2	92.2
Mizuho Research Institute	2.35	2.35	2.35	3.10	3.20	3.20	86.0	87.0	86.0
Moody's Analytics	na	na	na	3.35	3.67	3.92	na	na	na
Moody's Capital Markets	na	na	na	2.95	2.95	2.85	87.8	88.3	89.5
Nomura Securities	na	na	na	na	na	na	na	na	na
Oxford Economics	1.25	1.27	1.30	2.92	3.04	3.22	85.9	85.6	84.6
Scotiabank	na	na	na	2.90	3.00	3.07	na	na	na
Wells Fargo	2.30	2.55	2.80	2.95	3.05	3.32	na	NA	NA
May Consensus	**2.09**	**2.21**	**2.36**	**3.01**	**3.13**	**3.27**	**87.5**	**87.5**	**87.3**
High	2.45	2.65	3.00	3.35	3.67	3.92	91.7	91.2	92.2
Low	1.25	1.27	1.30	2.75	2.75	2.85	85.9	85.2	84.2
Last Months Avg.	2.24	2.41	2.74	2.98	3.08	3.26	87.0	87.0	87.0

Japan

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			USD/YEN		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	0.05	0.05	na	105.0	103.0	na
BMO Capital Markets	0.00	0.00	0.00	0.05	0.05	0.10	106.0	106.0	105.0
IHSMarkit	na	na	na	na	na	na	105.6	107.3	111.0
ING Financial Markets	0.00	0.00	0.00	0.10	0.10	0.10	105.0	103.0	100.0
Mizuho Research Institute	0.09	0.09	0.09	0.05	0.05	0.05	107.0	108.0	108.0
Moody's Analytics	na	na	na	0.06	0.06	0.04	111.3	111.6	110.7
Moody's Capital Markets	na	na	na	.0.06	0.08	0.10	110.0	111.0	112.0
Nomura Securities	na	na	na	na	na	na	108.0	110.0	110.0
Oxford Economics	na	na	na	0.07	0.08	0.08	107.6	109.0	112.3
Scotiabank	na	na	na	na	na	na	109.0	110.0	110.0
Wells Fargo	-0.02	-0.01	0.01	0.06	0.07	0.09	na	na	na
May Consensus	**0.02**	**0.02**	**0.03**	**0.06**	**0.07**	**0.08**	**107.5**	**107.9**	**108.8**
High	0.09	0.09	0.09	0.10	0.10	0.10	111.3	111.6	112.3
Low	-0.02	-0.01	0.00	0.05	0.05	0.04	105.0	103.0	100.0
Last Months Avg.	0.01	0.01	0.02	0.09	0.10	0.08	108.2	108.4	109.4

United Kingdom

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gilt Yields %			GBP/USD		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	1.60	1.70	na	1.40	1.42	na
BMO Capital Markets	0.85	0.85	0.85	1.65	1.75	2.05	1.42	1.43	1.44
IHSMarkit	na	na	na	na	na	na	1.41	1.40	1.39
ING Financial Markets	0.80	0.80	0.85	1.65	1.75	1.90	1.45	1.45	1.58
Mizuho Research Institute	0.85	0.85	1.10	1.70	1.75	1.90	na	na	na
Moody's Analytics	na	na	na	1.70	1.69	1.91	1.31	1.26	1.28
Moody's Capital Markets	na	na	na	1.52	1.60	1.75	1.38	1.38	1.39
Nomura Securities	na	na	na	na	na	na	1.43	1.48	1.56
Oxford Economics	na	na	na	1.68	1.94	2.35	1.41	1.44	1.47
Scotiabank	na	na	na	na	na	na	1.41	1.44	1.49
Wells Fargo	0.80	0.80	1.05	1.65	1.80	2.00	na	na	na
May Consensus	**0.83**	**0.83**	**0.96**	**1.64**	**1.75**	**1.98**	**1.40**	**1.41**	**1.45**
High	0.85	0.85	1.10	1.70	1.94	2.35	1.45	1.48	1.58
Low	0.80	0.80	0.85	1.52	1.60	1.75	1.31	1.26	1.28
Last Months Avg.	0.81	0.81	0.95	1.68	1.79	1.96	1.40	1.40	1.43

Switzerland

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			USD/CHF		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	na	na	na	0.97	0.97	na
BMO Capital Markets	na	na	na	na	na	na	na	na	na
IHSMarkit	na	na	na	na	na	na	0.97	0.97	0.98
ING Financial Markets	-0.75	-0.75	-0.75	0.15	0.20	0.40	0.95	0.95	0.96
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Moody's Analytics	na	na	na	0.24	0.32	0.49	1.00	1.06	1.03
Moody's Capital Markets	na	na	na	0.10	0.12	0.15	0.99	1.00	1.00
Nomura Securities	na	na	na	na	na	na	0.98	0.94	0.89
Oxford Economics	na	na	na	0.07	0.27	0.54	0.94	0.93	0.91
Scotiabank	na	na	na	na	na	na	na	na	na
Wells Fargo	na	na	na	na	na	na	na	na	na
May Consensus	**-0.75**	**-0.75**	**-0.75**	**0.14**	**0.23**	**0.40**	**0.97**	**0.97**	**0.96**
High	-0.75	-0.75	-0.75	0.24	0.32	0.54	1.00	1.06	1.03
Low	-0.75	-0.75	-0.75	0.07	0.12	0.15	0.94	0.93	0.89
Last Months Avg.	-0.75	-0.75	-0.75	0.18	0.26	0.40	0.97	0.96	0.96

Canada

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			USD/CAD		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	na	na	na	1.30	1.29	na
BMO Capital Markets	na	na	na	2.35	2.45	2.70	1.27	1.26	1.24
IHSMarkit	na	na	na	na	na	na	1.24	1.23	1.26
ING Financial Markets	1.80	2.00	2.00	2.40	2.60	2.80	1.24	1.22	1.20
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Moody's Analytics	na	na	na	3.18	3.63	3.97	1.27	1.25	1.23
Moody's Capital Markets	na	na	na	2.40	2.43	2.45	1.29	1.29	1.30
Nomura Securities	na	na	na	na	na	na	1.30	1.28	1.21
Oxford Economics	na	na	na	2.51	2.67	2.92	1.29	1.29	1.28
Scotiabank	na	na	na	2.32	2.45	2.62	1.27	1.27	1.24
Wells Fargo	1.75	1.90	2.15	2.30	2.50	2.60	na	na	na
May Consensus	**1.78**	**1.95**	**2.08**	**2.49**	**2.68**	**2.87**	**1.27**	**1.26**	**1.24**
High	1.80	2.00	2.15	3.18	3.63	3.97	1.30	1.29	1.30
Low	1.75	1.90	2.00	2.30	2.43	2.45	1.24	1.22	1.20
Last Months Avg.	1.78	1.95	2.08	2.48	2.62	2.86	1.27	1.26	1.24

International Interest Rate And Foreign Exchange Rate Forecasts

Australia

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			AUD/AUD		
Barclays	na	na	na	na	na	na	0.77	0.77	na
BMO Capital Markets	na	na	na	na	na	na	na	na	na
IHSMarkit	na	na	na	na	na	na	0.77	0.77	0.75
ING Financial Markets	1.80	1.90	2.20	3.00	3.10	3.30	0.78	0.80	0.85
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Moody's Analytics	na	na	na	2.65	2.68	2.81	0.75	0.74	0.72
Moody's Capital Markets	na	na	na	2.90	2.95	2.93	0.76	0.75	0.75
Nomura Securities	na	na	na	na	na	na	0.73	0.75	0.82
Oxford Economics	na	na	na	2.78	3.00	3.22	0.77	0.77	0.76
Scotiabank	na	na	na	na	na	na	0.79	0.80	0.81
Wells Fargo	na	na	na	na	na	na	na	na	na
May Consensus	**1.80**	**1.90**	**2.20**	**2.83**	**2.93**	**3.06**	**0.76**	**0.77**	**0.78**
High	1.80	1.90	2.20	3.00	3.10	3.30	0.79	0.80	0.85
Low	1.80	1.90	2.20	2.65	2.68	2.81	0.73	0.74	0.72
Last Months Avg.	1.80	1.90	2.20	2.87	2.90	3.02	0.78	0.78	0.79

Eurozone

Blue Chip Forecasters	3 Mo. Interest Rate %			USD/EUR		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	1.22	1.22	na
BMO Capital Markets	-0.35	-0.35	-0.35	1.24	1.25	1.26
IHSMarkit	na	na	na	1.22	1.21	1.20
ING Financial Markets	-0.33	-0.33	-0.25	1.28	1.28	1.31
Mizuho Research Institute	-0.30	-0.30	-0.20	1.24	1.25	1.26
Moody's Analytics	na	na	na	1.17	1.10	1.13
Moody's Capital Markets	na	na	na	1.20	1.20	1.19
Nomura Securities	na	na	na	1.23	1.27	1.40
Oxford Economics	na	na	na	1.25	1.27	1.30
Scotiabank	na	na	na	1.26	1.29	1.33
Wells Fargo	-0.35	-0.30	-0.10	na	na	na
May Consensus	**-0.33**	**-0.32**	**-0.23**	**1.23**	**1.23**	**1.26**
High	-0.30	-0.30	-0.10	1.28	1.29	1.40
Low	-0.35	-0.35	-0.35	1.17	1.10	1.13
Last Months Avg.	-0.33	-0.32	-0.23	1.23	1.23	1.25

Blue Chip Forecasters	10 Yr. Gov't Bond Yields %											
	Germany			France			Italy			Spain		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.70	0.75	na	na	na	na	na	na	na	na	na	na
BMO Capital Markets	0.75	0.90	1.15	na	na	na	na	na	na	na	na	na
ING Financial Markets	0.75	0.80	1.00	1.00	1.10	1.35	2.25	2.25	2.45	1.50	1.60	1.80
Mizuho Research Institute	0.70	0.75	0.75	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.83	1.02	1.38	1.03	1.15	1.39	2.08	2.21	2.46	1.90	2.07	2.35
Moody's Capital Markets	0.62	0.65	0.75	0.86	0.88	0.97	1.79	1.84	1.95	1.29	1.31	1.37
Nomura Securities	na	na	na	na	na	na	na	na	na	na	na	na
Oxford Economics	0.55	0.77	1.07	0.83	1.12	1.45	1.80	2.07	2.47	1.20	1.47	1.91
Wells Fargo	0.70	0.80	1.10	na	na	na	na	na	na	na	na	na
May Consensus	**0.70**	**0.81**	**1.03**	**0.93**	**1.06**	**1.29**	**1.98**	**2.09**	**2.33**	**1.47**	**1.61**	**1.86**
High	0.83	1.02	1.38	1.03	1.15	1.45	2.25	2.25	2.47	1.90	2.07	2.35
Low	0.55	0.65	0.75	0.83	0.88	0.97	1.79	1.84	1.95	1.20	1.31	1.37
Last Months Avg.	0.74	0.84	1.04	1.03	1.12	1.35	2.15	2.26	2.45	1.69	1.82	2.09

Consensus Forecasts
10-year Bond Yields vs U.S. Yield

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-2.94	-2.95	-3.06	-3.19
United Kingdom	-1.39	-1.37	-1.38	-1.29
Switzerland	-2.80	-2.87	-2.90	-2.88
Canada	-0.61	-0.52	-0.46	-0.41
Australia	-0.11	-0.18	-0.20	-0.21
Germany	-2.35	-2.31	-2.33	-2.25
France	-2.14	-2.08	-2.07	-1.98
Italy	-1.20	-1.03	-1.04	-0.94
Spain	-1.73	-1.54	-1.52	-1.42

Consensus Forecasts
3 Mo. Deposit Rates vs U.S. Rate

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-2.66	-2.07	-2.23	-2.34
United Kingdom	-1.61	-1.26	-1.38	-1.40
Switzerland	-3.09	-2.84	-2.96	-3.11
Canada	-0.67	-0.31	-0.26	-0.29
Australia	-0.22	-0.29	-0.31	-0.16
Eurozone	-2.69	-2.42	-2.53	-2.59

Viewpoints:

A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

FOMC Preview: Uneventful

There is not a great deal of mystery surrounding monetary policy at this time. Fed officials are in broad agreement on the proper path of policy in the current environment, with 12 of 15 policymakers anticipating a need for either three of four rate hikes this year. They plan to move gradually, and with the Federal Open Market Committee having just raised interest rates in March, the probability of a policy shift at the May 1-2 meeting is low. A logical expectation is for the Fed to move once each quarter (March, June, September, December). This provides the gradual adjustment desired by officials, and it meshes well with scheduled press conferences.

The upcoming meeting is likely to be interesting in one respect. The price index for personal consumption expenditures in March will be published two days before the rate decision, and the new figures are likely to suggest a quickening in the inflation rate. We expect the core index to increase modestly on a month-to-month basis (0.1%), but this change would leave a year-over-year increase of 1.9%, up from 1.6% in February and close to the Fed's target of 2.0%. The pickup in inflation is more obvious from a short-term perspective. Today's GDP report showed that the headline index for personal consumption expenditures rose at an annual rate of 2.7% in the first quarter. Part of the pressure was the result of higher energy prices, but the core index also rose briskly (2.5%).

The latest reading on the employment cost index -- arguably the best measure of labor compensation in the U.S. -- also is suggestive of faster inflation. This measure rose 0.8% in the first quarter (actually a touch more, 0.837%), which represented the sharpest increase of the current expansion and added to the upward trend that has emerged in the past year or two.

The latest news on wages and prices might lead some officials to support a near-term adjustment in policy, but we doubt that a shift at this time would gather much support. Core inflation is still below target, and officials are likely to tolerate inflation moderately above target for a time given its tendency to be below 2.0% in the past several years. Thus, the May 1-2 FOMC meeting is likely to be uneventful.

The Treasury Department this week might receive more attention than the Federal Reserve does. Debt managers will announce their plans for the mid-quarter refunding in May (the auction of 3-year and 10-year notes and 30-year bonds), and officials will most likely increase the auction sizes of these securities and perhaps indicate that sizes of other issues will be boosted in coming months. The tax cuts and spending increases authorized by Congress will widen the budget deficit considerably ($804 billion this fiscal year, and $981 billion in FY2019 according to estimates of the Congressional Budget Office, up from the actual deficit of $666 billion in FY2017). The Treasury Department must now raise the funds to cover the looming shortfalls.

The Treasury Department announced a first round of enlarged auctions at the February mid-quarter refunding, with combined issuance of nominal coupon securities in the past three months $42 billion larger than they would have been if the Treasury had kept auction sizes constant. We look for an announcement of additional increases this week, with the Treasury including inflation-protected securities (TIPS) in this round.

We wondered what might happen to auction sizes over the next few years because of the huge deficits and other funding needs. (Other funding needs include a rebuilding of the Treasury's cash balance this year after a meager total at the end of FY2017 because of debt-ceiling issues. In addition, the Treasury must provide funds for various loan programs that are not part of the federal budget. And, of course, the Treasury must refund maturing securities.) We set up a spreadsheet assuming that the Treasury would cover one-third of the funding needs in the bill market and two-thirds in the coupon sector. We also assumed that the Treasury will not alter the current structure of the auction schedule (i.e. it will not add new types of securities or increase the frequency of issuance for existing securities).

The result: Auction sizes must increase considerably -- by approximately 50% by the end of FY2019. We do not mean to portray the figures as a forecast of the Treasury auction schedule in the years ahead; rather, we simply wanted to have a sense of the funding challenge faced by the Treasury. The actual schedule will depend on the strategy pursued by the Treasury -- whether it emphasizes the short-term or long-term market, and whether it introduces new securities to limit volumes of the existing issues. We suspect that the Treasury will in fact introduce new securities or increase the frequency of existing issues, but one can only guess what debt managers might do. Thus, we would not put great store in any set of point estimates for auction sizes in the future, but we are confident that the Treasury's auction schedule in the years ahead will be crowded.

The economy (we hope) will be growing over the next two years, and auction sizes will be less daunting if scaled by GDP or some other macroeconomic metric. Still, issuance undoubtedly will be heavy even by scaled measures. The budget deficit will be climbing to the upper end of its historical range relative to GDP, and auction sizes will be following a similar path.

Interest rates have started to move higher, with the 10-year Treasury rate approximately 50 basis points higher than it was at the end of last year. We suspect that the expectation of wider budget deficits and heavy security issuance helped to push interest rates higher.

Other factors also seem to be in play. The break-even rate of 10-year inflation-protected securities has increased approximately 25 basis points since the turn of the year, suggesting that shifting expectations of inflation can explain about half of the rise in nominal rates.

Wider budget deficits would be influencing the 25 basis point increase in real rates, but other factors are probably involved as well. Market participants seem to have altered expectations for monetary policy, now accepting the view that the Fed will be hiking short-term interest rates three or four times this year, with additional increases unfolding next year. This shift in views would raise the expected path of short-term interest rates built into long-term yields. Term premiums embedded in long-term rates also may have increased, partly because the Fed is reducing its portfolio and partly because investors are more confident about global economic growth being well maintained (although Europe has shown signs of easing).

Some observers have sounded alarm about rising interest rates at a time when the Treasury Department will be flooding the market with new debt. They argue that the interest expense of the federal government will surge, limiting the ability of the government to pursue other activities. The concern is well founded, as projections of the Congressional Budget Office show an explosion in the government's interest bill over the next 10 years. (The projection is based on 3-month bill rates moving gradually from 1.9% this year to 3.7% in 2021-22 before easing to 2.8% in 2023-28; the 10-year Treasury rate is seen moving from 3.0% this year to 4.1% in 2021-22 and 3.7% in 2023-38). The picture is less frightening if scaled by GDP, but the interest burden will nevertheless be high by historical standards.

Michael Moran, Daiwa Capital Markets America, New York, NY

Been Down So Long, It Looks Up To Me

The global economy looks to have delivered its strongest two years of growth since 2011 as the dark shadow of the *(continued on next page)*

Viewpoints

A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

global financial crisis has finally lifted. With disruptive credit market aftershocks (first in the Euro area and then in the EM) now past, and behavioral headwinds fading fast, extremely accommodative monetary policies finally are bearing fruit. Although last quarter's deceleration in goods sector activity was a disappointment, we remain confident this will prove transitory and that strong fundamentals point to a rebound into midyear—led by a pickup in consumer spending gains. The latest data indicate consumer spending perked up in March, while this week's flash PMI readings for April from the US, Euro area, and Japan support the call that the 1Q momentum loss has been arrested and that global industry will maintain solid growth consistent with a reacceleration in global GDP.

Despite the signs of a return to the global business cycle, the sluggish expansion and low inflation since the financial crisis has led to a broader reassessment of the underlying economic structure. The need for persistently low policy rates in the face of premature fiscal tightening and private sector deleveraging reinforced the notion that equilibrium interest rates have fallen sharply and raised conviction that inflation would remain depressed even as labor markets tightened. With the link between growth and inflation perceived to have broken, markets still do not see DM central bank policy stances normalizing much in the foreseeable future.

If we are right, however, this perception will at long last moderate in the coming months. The shift will begin with a reaffirmation of the laws of supply and demand prompted by rising consumer price and wage inflation. Global core inflation remains low but the tide is starting to turn. In next week's reports we expect US core PCE inflation to approach the Fed's target as it rises to 1.9%oya in March. The upturn elsewhere is still more prospective—Euro area core inflation appears to have dipped back below 1%oya in April while the Tokyo April core inflation reading was soft—but we fade these outturns as a last gasp before moving higher. By the end of next year, we expect Euro area core inflation to be at 1.6%oya while we project Japan inflation to reach near 1.5%oya (excluding a projected VAT hike). At the same time, robust labor markets across most of the world are promoting a long-awaited pickup in wage inflation. The latest signal comes from the US reading of ECI labor compensation growth jumping in 1Q18 to its fastest pace of the expansion.

The improved growth and inflation backdrop will promote a reassessment of the view that equilibrium real interest rates have fallen to zero or lower. Rather, we believe DM equilibrium real interest rates are at about 1%. Combined with 2% inflation targets, nominal policy rates thus should be trending toward 3%. In the event, market perceptions that no DM policy rates reach 3% (and nearly all outside the US will remain below 2%) are set to be challenged, and we expect global interest rates to rise accordingly. In addition to rising short-term interest rates closely connected to central bank normalization, long-term interest rates also will move up as views of equilibrium rates and inflation risk reset. The recent rise in US 10- year yields reflects each of these developments. Tips markets show real yields rising from 0.4% since the start of the year to close to 0.8%, while 5yr-5yr breakevens also have moved up materially to their highest level since 2014.

As interest rates reflect changes in the economic landscape, they also can shape the outlook. Rising rates eventually will be a catalyst for the end of this phase of synchronized global growth. However, while we see a move that is larger than markets are pricing, it is still likely to be relatively slow. Central banks are cautious and seem biased to allow some overshoot of their inflation targets. At the same time, our strategy colleagues find that term premia have been lowered structurally by elevated DM central bank balance sheets, EM FX reserve accumulation, and greater stability in central bank reaction functions (see here). Consequently, the main mediumterm threat comes less from the risk of a disorderly repricing in rates but rather from imbalances created by such an extended period of easy money. Indeed, history has shown how even a "measured pace" of interest rate hikes can reveal these imbalances in ways that foster financial stress.

Bruce Kasman, David Hensley and Joseph Lupton, JPMorgan Chase Bank, New York, NY

Motor Vehicles Get Pulled Over

Real GDP growth slowed in the first quarter to an annualized pace of 2.3%. One key reason for the slower growth rate was that consumer spending grew at just a 1.1% annualized clip. That is the slowest pace in more than four and a half years. What happened to surging consumer confidence and tax cuts?

Admittedly, the 4.0% growth rate in the final quarter of 2017 was a tough act to follow. Some of the Q4 strength in consumer spending had to do with revved-up auto sales after hurricanerelated flooding resulted in replacement spending at the time. Outlays for motor vehicles added 0.45 percentage points to Q4 growth and subtracted 0.42 percentage points from Q1.

We are not worried about the consumer. We learned this week that consumer confidence rose to 128.7—the second-highest level reached for this bellwether since 2000. Similarly, the unemployment rate, which presently is 4.1%, has not been so low since 2000. In fact, we are just a few ticks away from 3.8%, the cycle low in 2000. To find a lower unemployment rate, you need to go back to the 1960s. While participation is not what it used to be, it stands to reason that the job market is presently in good enough shape to sustain further growth in consumer spending.

Double-digit percentage gains in orders for both civilian and defense aircraft lifted overall durable goods orders to a better-than-expected monthly increase of 2.6%. But elsewhere, orders were flat in March when you exclude the volatile transportation sector. Despite sustained high levels for ISM new orders, actual orders remain inconsistent.

Core capital goods shipments tend to be a good indicator for equipment spending, and that offered a last minute preview for the equipment line in Friday's GDP report, as this series posted a three-month annualized growth rate of just 4.1%. The equipment spending line in the GDP report was 4.7%.

The notion that the soft patch in capital spending might only be delayed is sullied by the fact that core capital goods orders fell in March, and the three-month annualized rate is in negative territory. We have been forecasting a moderation in the pace of capital spending despite the tax cuts, and that forecast (regrettably) remains intact.

Although business spending on equipment slowed, spending on structures picked up. Nonresidential fixed investment spending grew at a 12.3% clip in Q1.

March new home sales jumped 4.0%, which exceeded the 1.9% gain that had been expected. Not only that, the data for the prior month (February) were revised higher as well. The annualized pace of new home sales, now at 694K, represents the fastest pace of the current expansion. Weather still appears to be playing a factor. New home sales were down in the Northeast as realtors perhaps found it difficult to get potential buyers to look at listings in a month in which four nor'easters pummeled the region.

Economics Group, Wells Fargo, Charlotte, NC

Special Questions:

1. At which meeting will the Federal Reserve's Open Market Committee NEXT raise interest rates?

(Percentage of those responding)

May 1-2	Jun 12-13	Jul 31-Aug. 1	Sep. 25-26	Later
0.0%	95.1%	0.0%	4.9%	0.0%

2. The FOMC raised interest rates by 25 basis points in March. By how many TOTAL basis points will the FOMC raise interest rates in 2018?

Total basis point increase in interest rates by FOMC in 2018:
(Percentage of those responding)

50 b.p.	75 b.p.	100 b.p.	More than 100 b.p.
2.5%	37.5%	60.0%	0.0%

3. By how many basis points will the FOMC raise interest rates in 2019?

Total basis point increase in interest rates by FOMC in 2019:
(Percentage of those responding)

0 b.p.	25 b.p.	50 b.p.	75 b.p.	100 b.p.	More than 100 b.p.
2.6%	10.3%	28.2%	33.3%	25.6%	0.0%

4. What will be the terminal level for the federal funds rate during the FOMC's current tightening cycle?

	Terminal fed funds rate
Consensus	**3.22%**
Top 10 Average	4.09%
Bottom 10 Average	2.46%

5. The personal consumption expenditures (PCE) price index was up 1.8% on a year-over-year basis in February. What will be the December-over-December change in the PCE Price Index in 2018 and 2019?

December-over-December change in the PCE Price Index:

	2018	2019
Consensus	**2.1%**	**2.1%**
Top 10 Average	2.4%	2.4%
Bottom 10 Average	1.8%	1.8%

6. What will be the unemployment rate in December 2018 and 2019?

Unemployment rate in December:

	2018	2019
Consensus	**3.7%**	**3.6%**
Top 10 Average	3.9%	4.0%
Bottom 10 Average	3.5%	3.3%

7. Will the 2-year/10-year Treasury curve invert in 2018? If not in 2018, will it invert in 2019?

Will the 2yr/10yr Treasury curve invert in 2018
(Percentage of those responding)

Yes	No
5.4%	94.6%

Will the 2yr/10yr Treasury curve invert in 2018
(Percentage of those responding)

Yes	No
8.6%	91.4%

8. What are the odds that a U.S. recession will begin in 2018? If not in 2018, what are the odds that a recession will begin in 2019?

(Between 0% and 100%)
Odds of a U.S. recession in:

	2018	2019
Consensus	**13.9%**	**25.0%**
Top 10 Average	22.0%	36.2%
Bottom 10 Average	7.5%	15.9%

Databank:

2018 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	-0.2	-0.1	0.6									
Auto & Light Truck Sales (b)	17.08	16.98	17.40									
Personal Income (a, current $)	0.4	0.4										
Personal Consumption (a, current $)	0.2	0.2										
Consumer Credit (e)	4.9	3.3										
Consumer Sentiment (U. of Mich.)	95.7	99.7	101.4	98.8								
Household Employment (c)	409	785	-37									
Non-farm Payroll Employment (c)	176	326	103									
Unemployment Rate (%)	4.1	4.1	4.1									
Average Hourly Earnings (All, cur. $)	26.71	26.74	26.82									
Average Workweek (All, hrs.)	34.4	34.5	34.5									
Industrial Production (d)	3.0	4.3	4.4									
Capacity Utilization (%)	77.1	77.7	78.0									
ISM Manufacturing Index (g)	59.1	60.8	59.3									
ISM Non-Manufacturing Index (g)	59.9	59.5	58.8									
Housing Starts (b)	1.339	1.295	1.319									
Housing Permits (b)	1.377	1.321	1.354									
New Home Sales (1-family, c)	644	667	694									
Construction Expenditures (a)	0.0	0.1										
Consumer Price Index (nsa., d)	2.1	2.2	2.4									
CPI ex. Food and Energy (nsa., d)	1.8	1.8	2.1									
Producer Price Index (n.s.a., d)	2.7	2.8	3.0									
Durable Goods Orders (a)	-3.6	3.5	2.6									
Leading Economic Indicators (g)	0.8	0.7	0.3									
Balance of Trade & Services (f)	-56.7	-57.6										
Federal Funds Rate (%)	1.29	1.42	1.49									
3-Mo. Treasury Bill Rate (%)	1.43	1.57	1.73									
10-Year Treasury Note Yield (%)	2.56	2.86	2.84									

2017 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	0.5	-0.2	0.1	0.3	0.0	-0.1	0.5	-0.1	2.0	0.7	0.8	-0.1
Auto & Light Truck Sales (b)	17.34	17.33	16.72	16.97	16.70	16.61	16.69	16.02	18.49	18.00	17.42	17.75
Personal Income (a, current $)	0.4	0.5	0.3	0.1	0.3	0.0	0.4	0.3	0.5	0.4	0.3	0.4
Personal Consumption (a, current $)	0.2	0.1	0.5	0.3	0.2	0.1	0.3	0.2	1.0	0.3	0.7	0.5
Consumer Credit (e)	3.1	5.2	4.7	3.9	5.8	3.7	5.7	3.7	5.7	5.8	9.8	6.0
Consumer Sentiment (U. of Mich.)	98.5	96.3	96.9	97.0	97.1	95.1	93.4	96.8	95.1	100.7	98.5	95.9
Household Employment (c)	-157	435	553	97	-269	358	261	-40	853	-478	71	104
Non-Farm Payroll Employment (c)	259	200	73	175	155	239	190	221	14	271	216	175
Unemployment Rate (%)	4.8	4.7	4.5	4.4	4.3	4.3	4.3	4.4	4.2	4.1	4.1	4.1
Average Hourly Earnings (All, cur. $)	25.99	26.07	26.11	26.17	26.21	26.26	26.34	26.39	26.51	26.47	26.54	26.64
Average Workweek (All, hrs.)	34.4	34.4	34.3	34.4	34.4	34.4	34.4	34.4	34.3	34.4	34.5	34.5
Industrial Production (d)	-0.5	-0.1	1.2	2.0	2.1	1.9	1.5	1.1	1.3	2.6	3.4	2.9
Capacity Utilization (%)	75.4	75.1	75.5	76.2	76.2	76.2	76.1	75.7	75.7	76.8	77.1	77.3
ISM Manufacturing Index (g)	56.0	57.6	56.6	55.3	55.5	56.7	56.5	59.3	60.2	58.5	58.2	59.3
ISM Non-Manufacturing Index (g)	56.5	57.4	55.6	57.3	57.1	57.2	54.3	55.2	59.4	59.8	57.3	56.0
Housing Starts (b)	1.236	1.288	1.189	1.154	1.129	1.217	1.185	1.172	1.159	1.261	1.299	1.207
Housing Permits (b)	1.300	1.219	1.260	1.228	1.168	1.275	1.230	1.272	1.225	1.316	1.303	1.300
New Home Sales (1-family, c)	599	615	638	590	606	619	564	559	639	616	711	644
Construction Expenditures (a)	0.8	1.9	0.3	-1.8	1.6	-0.8	-0.9	0.5	1.3	0.1	1.2	0.8
Consumer Price Index (s.a., d)	2.5	2.7	2.4	2.2	1.9	1.6	1.7	1.9	2.2	2.0	2.2	2.1
CPI ex. Food and Energy (s.a., d)	2.3	2.2	2.0	1.9	1.7	1.7	1.7	1.7	1.7	1.8	1.7	1.8
Producer Price Index (n.s.a., d)	1.7	2.0	2.2	2.5	2.3	1.9	2.0	2.4	2.6	2.8	3.0	2.6
Durable Goods Orders (a)	2.4	1.4	2.4	-0.8	0.0	6.4	-6.8	2.1	2.4	-0.4	1.7	2.7
Leading Economic Indicators (g)	0.6	0.5	0.4	0.2	0.3	0.6	0.3	0.4	0.1	1.3	0.4	1.6
Balance of Trade & Services (f)	-48.7	-44.4	-44.7	-48.1	-47.8	-45.6	-45.4	-44.6	-45.3	-49.1	-50.9	-53.9
Federal Funds Rate (%)	0.65	0.66	0.76	0.90	0.90	1.03	1.15	1.15	1.16	1.15	1.15	1.29
3-Mo. Treasury Bill Rate (%)	0.51	0.53	0.73	0.80	0.90	1.02	1.09	1.04	1.06	1.09	1.23	1.33
10-Year Treasury Note Yield (%)	2.43	2.43	2.47	2.30	2.31	2.19	2.32	2.33	2.28	2.36	2.36	2.40

(a) month-over-month % change; (b) millions, saar; (c) month-over-month change, thousands; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level. Most series are subject to frequent government revisions. Use with care.

Calendar Of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
April 30 Personal Income and Consumption (Mar) Chicago PMI (Apr) Dallas Fed Manufacturing (Apr) Pending Home Sales (Mar)	**May 1** **FOMC Meeting** ISM Manufacturing (Apr) IHSMarkit Manufacturing (Apr, Final) Light Vehicle Sales (Apr) Construction Spending (Mar) Dallas Fed Services (Apr) Light Vehicle Sales (Apr)	**2** **FOMC Meeting** **Statement 2:00 p.m.** ADP Employment (Apr) EIA Crude Oil Stocks Mortgage Applications	**3** International Trade (Mar) IHSMarkit Services (Apr, Final) ISM Nonmanufacturing (Apr) Factory Orders (Mar) Productivity and Coasts (Q1, Preliminary) Weekly Jobless Claims Weekly Money Supply	**4** Employment (Apr)
7 Consumer Credit (Mar) Senior Loan Officer Survey (Q2)	**8** JOLTS (Mar) NFIB Survey (Apr)	**9** Producer Price Index (Apr) Wholesale Trade (Mar) EIA Crude Oil Stocks Mortgage Applications	**10** Consumer Price Index (Apr) Federal Budget (Apr) Weekly Jobless Claims Weekly Money Supply	**11** Imports Prices (Apr) Consumer Sentiment (May, Preliminary, Univ. of Michigan)
14	**15** Retail Sales (Apr) Empire State Manufacturing (May) Business Inventories (Mar) NAHB Survey (May) TIC Data (Mar)	**16** Housing Starts (Apr) Business Leaders Survey (May) Industrial Production (Apr) EIA Crude Oil Stocks Mortgage Applications	**17** Philadelphia Fed Manufacturing (May) Weekly Jobless Claims Weekly Money Supply	**18** Quarterly Services Survey (Q1, Advance)
21	**22** Philadelphia Fed Non-Manufacturing (May) Richmond Fed Surveys (May)	**23** **FOMC Minutes** Manufacturing PMI (May Flash) Services PMI (May Flash) New Home Sales (Apr) EIA Crude Oil Stocks Mortgage Applications	**24** Kansas City Fed Survey (May) Existing Home Sales (Apr) FHFA Home Price Index (Mar, Q1) Weekly Jobless Claims Weekly Money Supply	**25** Durable Goods (Apr) Consumer Sentiment (May, Final, University of Michigan)
28 **Memorial Day** **U.S. Markets Closed**	**29** Dallas Fed Manufacturing (May) Consumer Confidence (May, Conference Board)	**30** ADP Employment (May) Real GDP (Q1, Second) Advance Economic Indicators (Apr) Dallas Fed Services (May) Beige Book EIA Crude Oil Stocks Mortgage Applications	**31** Personal Income and Consumption (Apr) Chicago PMI (May) Pending Home Sales (Apr) Weekly Jobless Claims Weekly Money Supply	**June 1** Employment (May) Manufacturing PMI (May, Final) ISM Manufacturing (May) Light Vehicle Sales (May) Construction Expenditures (Apr)
4 Factory Orders (Apr)	**5** Services PMI (May, Final) ISM Non-Manufacturing (May) JOLTS (Apr)	**6** International Trade (Apr) Productivity and Costs (Q1, Revised) EIA Crude Oil Stocks Mortgage Applications	**7** Consumer Credit (Apr) Quarterly Services Survey (Q1) Weekly Jobless Claims Weekly Money Supply	**8** Wholesale Trade (Apr)

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Blue Chip Financial Forecasts®

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A December FOMC Hike, Followed By Maybe 75 Basis Points More In 2018

Domestic Commentary As expected, the Federal Reserve's Open Market Committee (FOMC) left interest rates unchanged at its October 31st-November 1st meeting. Minutes of the meeting did not contain explicit guidance on future changes in policy. However, the discussion among policymakers suggested that barring a surprise policymakers will enact their third 25-basis-point increase of the year at their December 12th-13th meeting.

That is clearly the belief among our panelists. In response to a special question asked as part of our November 21st-22nd survey, the panelists unanimously predicted that at the December meeting the FOMC will hike its target range for the federal funds rate by a further 25 basis points to 1.25%-1.50%.

Minutes of the FOMC meeting noted that labor market conditions had generally continued to strengthen since its mid-September meeting and that real GDP growth expanded at a solid pace during Q3 despite the hurricane-related disruptions. Additionally, "many" meeting participants believed that the slowdown in inflation over the spring and summer months was largely the result of temporary or idiosyncratic factors; and that "most" felt that cyclical pressures would produce a pickup in inflation over the medium term. High frequency data released since the FOMC's most recent meeting have tended to underscore these views.

Job growth rebounded sharply in October following the hurricane-induced softness in September and most economists look for another solid increase in November payrolls. Moreover, October's unemployment rate fell to a fresh 17-year low of 4.1%. While the year-over-year (y/y) change in average hourly earnings slipped back a bit in October, most economists look for a rebound over coming months as labor market conditions continue to tighten as the economy grows at an above-trend pace.

Industrial production and consumer spending also have exhibited signs of solid growth. The y/y change in total industrial production increased to 2.8% in October, the fastest pace since early 2012. Retail sales grew at an annual rate of 3.5% over the three-months ending in October and most signs point to strong holiday spending this year. Moreover, shipments of core capital goods – a proxy for capital spending – were up 12.0% at an annual rate over the three months ending in October. Residential investment, too, has recently exhibited some much needed strengthening. Housing starts surged nearly 14% in October and replacement and recovery efforts following the hurricanes now seems likely to ensure that real residential investment posts positive growth in the current quarter after contracting in each of the two prior quarters.

The consensus this month forecasts that real GDP would grow at an above-trend rate of 2.7% (saar) in the final quarter of this year. That forecast is unchanged from a month ago, but risks to it might be to the upside. Indeed, as of November 22nd the Atlanta Federal Reserve Bank's GDPNow forecast estimated that real GDP will grow 3.4% (saar) this quarter. Furthermore, a good many of our panelists believe that real GDP growth in Q3 – currently estimated by the Bureau of Economic Analysis at 3.1% (saar) – will be revised up by a couple of tenths on November 29th.

The most plausible roadblock standing in the way of a rate hike in mid-December is the possibility of a federal government shutdown that might prompt FOMC members to delay action. The Senate needs 60 votes to pass another short-term budget extension prior to December 8th to avoid a shutdown. However, Democrats are unlikely to agree without concessions, such as an extension of the Deferred Action for Childhood Arrivals (DACA) program and/or renewal of the Children's Health Insurance program.

Failure to agree on a budget extension would not only lead to a partial shutdown of the federal government, but make it all but impossible for Republicans to meet their deadline for passing tax reform legislation prior to the Christmas recess. President Trump and top congressional leaders are scheduled to meet the week following Thanksgiving in an attempt to hammer out a deal on a temporary budget extension. Stay tuned.

Beyond this December, the prospect for additional rate hikes from the FOMC becomes more clouded. The FOMC's September "dot plot" continued to suggest an additional 100 basis points of tightening in 2018. However, minutes of the FOMC's most recent meeting hint that at least some policymakers are concerned that longer-term inflation expectations have fallen, thereby necessitating a slower-than-previously assumed pace for interest rate normalization. For example, "a number of these participants were worried that a decline in longer-term inflation expectations would make it more challenging for the Committee to promote a return of inflation to 2 percent over the medium term". This has led some to suspect that the "dot plot" released in conjunction with the December FOMC meeting might imply fewer rate increases in 2018 than did the September "dot plot". However, we suspect that will not occur given the economy's current strength, the grudging upturn in inflation, and the rich valuations seen across a host of asset classes.

As for our panelists' view on 2018 rate changes, this month's special questions showed 11.9% of those responding predicted only one 25 basis point hike in rates next year; 35.7% forecast 50 basis points of tightening, 23.8% expected 75 basis points of rate hikes, and 28.6% forecast a full 100 basis points of rate increases next year.

Real GDP still is predicted by the consensus to grow 2.4% (saar) in Q1 of next year, but the forecast for growth in Q2 rose another 0.1 of a percentage point this month to 2.6% (saar). Real GDP is forecast to grow 2.3% (saar)in Q3 and Q4 of next year, the Q3 estimate dipping by 0.1 of a percentage point over the past month. The consensus forecast of real GDP growth in Q1 2019 remained at 2.1% (saar) this month. These forecasts will be subject to revision not only if and when Congress acts on tax reform, but what the legislation ultimately entails. The consensus this month puts the odds that tax reform legislation will be passed by Congress prior to the end of this year at only 41%, but the odds of it passing in 2018 rose to 61%.

Consensus forecasts of inflation this quarter and next rose this month. After increasing 2.0% (saar) in Q3 of this year, the Consumer Price Index (CPI) is now forecast to increase 3.0% in the current quarter, 0.4 of a percentage point faster than predicted last month. The GDP price index is forecast to increase 2.2% (saar) this quarter, the same as in Q3, but 0.2 of a percentage point faster than forecast last month. The CPI is forecast to increase 2.2% (saar) in Q1 2018, up 0.2 of a percentage point from last month, while the forecast of the change in the GDP price index rose 0.1 of a point to 2.0% (saar). Forecasts of the Q2 2018 change in the CPI and GDP price index fell 0.1 of a percentage point to 1.9%. The consensus forecasts that the GDP price index and the CPI will increase at respective rates of 2.1% and 2.2% in Q3 and Q4 of next year. Both still are predicted to increase at respective rates of 2.2% and 2.3% in Q1 2019.

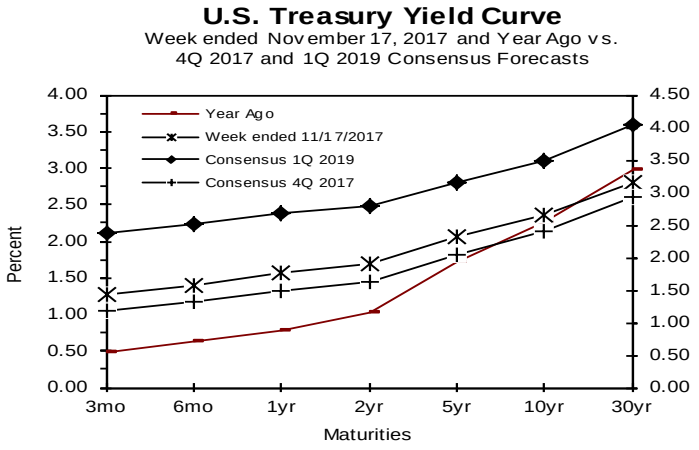
Consensus Forecast Real GDP will continue to grow at an above-trend pace through Q1 2019, tightening labor markets, and lifting inflation toward the FOMC 2.0% target. The FOMC will hike interest rates by 25 basis points this December and maybe 75 basis points more in 2018. The Treasury yield curve is likely to narrow by a bit more over the forecast horizon. After falling by about 10% this year on a trade-weighted basis, the U.S. dollar is predicted to be relatively stable over the forecast horizon *(see page 2).*

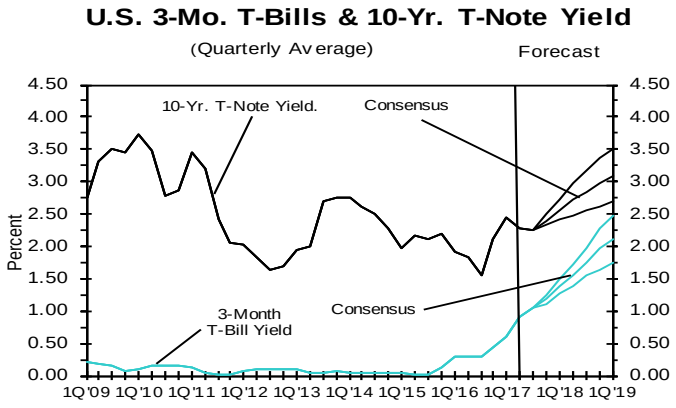
Special Questions On page 14 of this issue are results of our twice-yearly, long-range survey with consensus estimates for the years 2019 through 2023 and averages for the 5-year periods 2019-2023 and 2024-2028.

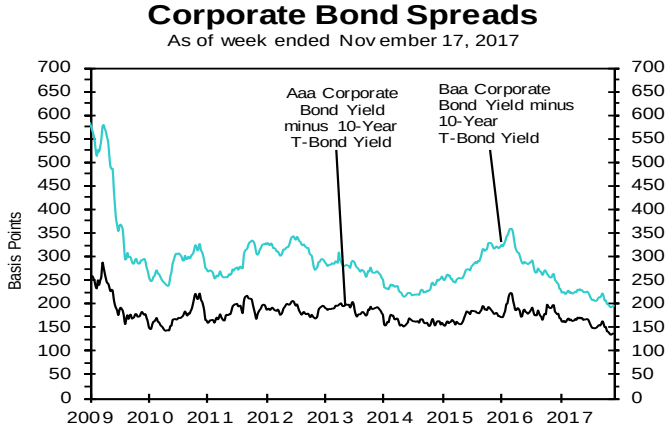
Consensus Forecasts Of U.S. Interest Rates And Key Assumptions[1]

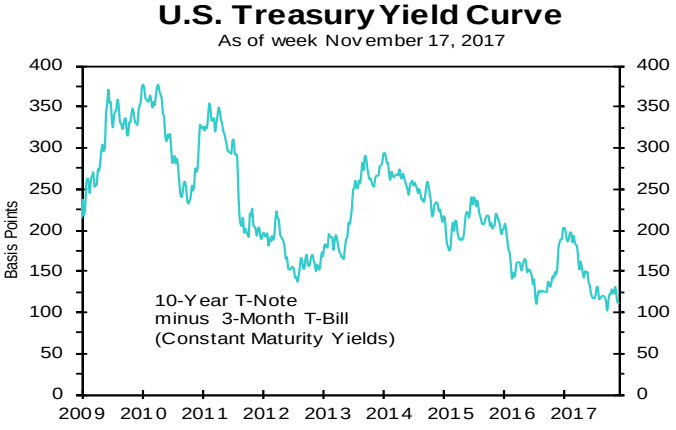
Interest Rates	Nov. 17	Nov. 10	Nov. 3	Oct. 27	Oct	Sep	Aug	3Q 2017	4Q 2017	1Q 2018	2Q 2018	3Q 2018	4Q 2018	1Q 2019
	History: Average For Week Ending				Average For Month			Latest Qtr	Consensus Forecasts-Quarterly Avg.					
Federal Funds Rate	1.16	1.16	1.15	1.16	1.15	1.16	1.16	1.16	1.2	1.4	1.6	1.8	2.0	2.2
Prime Rate	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.3	4.5	4.7	4.9	5.1	5.2
LIBOR, 3-mo.	1.43	1.41	1.39	1.37	1.36	1.33	1.31	1.32	1.4	1.6	1.8	2.0	2.2	2.4
Commercial Paper, 1-mo.	1.15	1.16	1.14	1.14	1.13	1.12	1.10	1.11	1.2	1.4	1.6	1.8	2.0	2.2
Treasury bill, 3-mo.	1.26	1.22	1.16	1.11	1.09	1.06	1.04	1.05	1.2	1.4	1.6	1.7	2.0	2.1
Treasury bill, 6-mo.	1.40	1.34	1.28	1.27	1.25	1.19	1.13	1.17	1.3	1.5	1.7	1.9	2.1	2.2
Treasury bill, 1 yr.	1.57	1.52	1.45	1.43	1.40	1.31	1.23	1.28	1.5	1.7	1.9	2.0	2.3	2.4
Treasury note, 2 yr.	1.70	1.64	1.61	1.60	1.54	1.46	1.34	1.41	1.6	1.8	2.0	2.2	2.3	2.5
Treasury note, 5 yr.	2.06	2.01	2.00	2.04	1.98	1.89	1.79	1.85	2.0	2.2	2.4	2.5	2.7	2.8
Treasury note, 10 yr.	2.37	2.34	2.36	2.42	2.36	2.28	2.23	2.26	2.4	2.6	2.7	2.8	3.0	3.1
Treasury note, 30 yr.	2.81	2.81	2.85	2.93	2.88	2.83	2.81	2.82	2.9	3.1	3.3	3.4	3.5	3.6
Corporate Aaa bond	3.74	3.71	3.71	3.77	3.75	3.75	3.76	3.76	3.8	4.0	4.2	4.3	4.5	4.6
Corporate Baa bond	4.32	4.29	4.29	4.35	4.32	4.32	4.34	4.33	4.4	4.6	4.9	5.1	5.2	5.3
State & Local bonds	3.41	3.37	3.40	3.38	3.37	3.34	3.35	3.34	3.5	3.7	3.9	4.0	4.2	4.3
Home mortgage rate	3.95	3.90	3.94	3.94	3.90	3.82	3.88	3.85	4.0	4.2	4.4	4.5	4.6	4.8
	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q
Key Assumptions	2015	2016	2016	2016	2016	2017	2017	2017	2017	2018	2018	2018	2018	2019
	History								Consensus Forecasts-Quarterly					
Major Currency Index	93.1	93.3	89.6	90.3	93.7	94.4	93.0	88.3	88.7	89.0	89.1	89.1	88.9	88.5
Real GDP	0.5	0.6	2.2	2.8	1.8	1.2	3.1	3.0	2.7	2.4	2.6	2.3	2.3	2.1
GDP Price Index	0.8	0.3	2.4	1.4	2.0	2.0	1.0	2.2	2.2	2.0	1.9	2.1	2.1	2.2
Consumer Price Index	0.4	0.1	2.3	1.8	3.0	3.1	-0.3	2.0	3.0	2.2	1.9	2.2	2.2	2.3

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; LIBOR quotes from Intercontinental Exchange. All interest rate data is sourced from Haver Analytics. Historical data for Fed's Major Currency Index is from FRSR H.10. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS).









----------3-Month Interest Rates[1]----------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	1.45	1.37	0.92	**1.66**	**1.91**	**2.14**
Japan	-0.04	-0.03	-0.06	**0.02**	**0.01**	**0.02**
U.K.	0.44	0.35	0.38	**0.60**	**0.63**	**0.81**
Switzerland	-0.75	0.02	-0.75	**-0.70**	**-0.70**	**-0.60**
Canada	1.35	1.35	0.85	**1.78**	**1.88**	**1.80**
Australia	1.98	1.85	2.21	**1.90**	**1.90**	**2.15**
Eurozone	-0.33	-0.33	-0.31	**-0.35**	**-0.32**	**-0.25**

----------10-Yr. Government Bond Yields[2]------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	2.36	2.41	2.29	**2.54**	**2.64**	**2.82**
Germany	0.35	0.48	0.26	**0.56**	**0.66**	**0.83**
Japan	0.03	0.07	0.03	**0.06**	**0.07**	**0.08**
U.K.	1.33	1.35	1.46	**1.48**	**1.57**	**1.72**
France	0.66	0.88	0.71	**0.93**	**1.02**	**1.19**
Italy	1.77	2.04	2.13	**2.09**	**2.13**	**2.28**
Switzerland	-0.09	-0.73	-0.15	**0.00**	**0.10**	**0.26**
Canada	1.90	2.07	1.54	**2.24**	**2.37**	**2.63**
Australia	2.53	2.76	2.65	**2.74**	**2.83**	**2.96**
Spain	1.48	1.65	1.53	**1.78**	**1.86**	**2.01**

----------Foreign Exchange Rates[1]----------

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	88.916	88.759	94.965	**89.4**	**89.8**	**89.0**
Japan	111.98	113.50	110.51	**114.4**	**114.8**	**114.8**
U.K.	1.3222	1.3179	1.2327	**1.33**	**1.34**	**1.36**
Switzerland	0.9882	0.9844	1.0094	**0.98**	**0.98**	**0.97**
Canada	1.2785	1.2618	1.3518	**1.27**	**1.26**	**1.25**
Australia	0.7563	0.7812	0.7345	**0.78**	**0.78**	**0.79**
Euro	1.1799	1.1770	1.0600	**1.18**	**1.18**	**1.21**

	Consensus 3-Month Rates vs. U.S. Rate			Consensus 10-Year Gov't Yields vs. U.S. Yield	
	Now	In 12 Mo.		Now	In 12
Japan	-1.49	**-2.12**	Germany	-2.01	**-1.98**
U.K.	-1.01	**-1.33**	Japan	-2.33	**-2.73**
Switzerland	-2.20	**-2.74**	U.K.	-1.03	**-1.09**
Canada	-0.10	**-0.34**	France	-1.70	**-1.62**
Australia	0.53	**0.01**	Italy	-0.59	**-0.54**
Eurozone	-1.78	**-2.38**	Switzerland	-2.45	**-2.56**
			Canada	-0.46	**-0.18**
			Australia	0.17	**0.14**
			Spain	-0.88	**-0.81**

Forecasts of panel members are on pages 10 and 11. Definitions of variables are as follows: [1]Three month rate on interest-earning money market deposits denominated in selected currencies. [2]Government bonds are yields to maturity. Foreign exchange rate forecasts for U.K., Australia and the Euro are U.S. dollars per currency unit. For the U.S dollar, forecasts are of the U.S. Federal Reserve Board's Major Currency Index.

International Commentary Eurozone real GDP growth grew a healthy 2.5% (saar) in Q3 and was up 2.5% y/y, the best pace since Q1 2011. Real GDP in Germany grew 3.3% (saar) in Q3 and was up 2.8% y/y while France's economy grew 1.9% (saar) and was up 2.2%, also the fastest since 2011. Spain's economy grew 3.2% (saar). Italy's economy grew 2.0% (saar) and was up 1.8%, also the best pace since Q1 2011. The unemployment rate in the Eurozone has fallen to 8.9%, the lowest since February 2009, but varies widely within the currency zone. Headline consumer price inflation in the Eurozone fell back to 1.4% y/y in October and core inflation dropped to 0.9%. The European Central Bank's (ECB) monthly bond purchases will fall to 30 billion euros beginning in January, but its purchase program has been extended until at least September 2018. No interest rate increases are expected from the ECB until 2019.

U.K. real GDP grew 1.6% (saar) in Q3 as consumers pushed spending to the fastest pace in a year. On a y/y basis, it was up 1.5% in Q3. However, growth is expected to slow in Q4 as consumer spending softens in the face of inflation that continues to exceed wage gains, high levels of consumer debt, Brexit worries, and political uncertainty. The release of the latest Q3 growth estimate came a day after the Office for Budget Responsibility (OBR), the independent fiscal watchdog, slashed its forecasts of future productivity and GDP growth. It now predicts real GDP growth next year of 1.4% and 1.3% in both 2019 and 2020. Consumer price inflation remained at 3.0% (y/y) in October, besting growth in average weekly earnings by almost a percentage point. The Bank of England raised interest rates by 25 basis points in November, the first increase in more than a decade. However, the prospect of slower economic growth, coupled with expectations that inflation will slow, has most analysts predicting the BoE will hike rates perhaps just once or twice in 2018.

After growing at a blistering pace of 3.7% clip over the four quarters ending in Q2, annualized real GDP growth in Canada appears to have slowed to about half that rate in Q3. Real GDP contracted 0.1% in August after being unchanged in July. Slower export growth and softer consumer spending appears to have been the biggest culprits behind the slowdown, but a further pullback in residential investment also likely occurred as the housing sector continues to come off its previous boil. The Bank of Canada (BoC) left interest rates unchanged at its October meeting after surprising markets with a second, consecutive 25 basis point rate hike in early September that lifted its overnight policy rate to 1.0%. Moreover, the October policy statement was decidedly more cautious than its September counterpart, citing concerns about NAFTA negotiations, weak exports, and the sensitivity of households to higher interest rates given record levels of debt. Most analysts suspect the BoC will delay until spring another hike in rates.

Real GDP in Japan grew 1.4% (saar) in Q3, marking the seventh consecutive quarter of expansion, the longest streak in 16 years. Growth in Q3 was driven by exports that rose at an annualized rate of 6.0%, coupled with a nice add from inventories. Private consumption actually fell in Q3, contracting 1.8% (saar). Also contracting during the quarter were residential construction and government consumption. Business investment grew 1.0% (saar), about half the pace seen during the first half of the year. Despite solid GDP growth and record low unemployment, inflation remains very low. As a result, the Bank of Japan is widely expected to maintain its very accommodative policy stance throughout the coming year.

At its November meeting, the Reserve Bank of Australia (RBA) left its cash rate unchanged at a record low of 1.5% for a 15th consecutive time. While GDP growth has held up reasonably well average hourly earnings are growing at their slowest pace since the 1960s despite near full employment, frustrating RBA policymakers worried about low inflation. Worrisome to many analysts is that home mortgage debt has soared to four times the size of Australia's GDP, much higher than in the U.S. prior to the America's housing crisis. Most analysts think RBA policy is likely to remain on hold well into next year *(see pages 10-11 for individual panelists' forecasts).*

Fourth Quarter 2017

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr. A. Fed's Major Currency $ Index	(Q-Q % Change) (SAAR) B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Scotiabank Group	1.5 H	4.5 H	na	na	1.3	na	na	1.7	2.1	2.4	2.9	na	na	na	na	na	2.8	1.5	2.0
Chase Wealth Management	1.4	4.5 H	1.6 H	1.4 H	1.3 H	1.5 H	1.6 H	1.7	2.1	2.5	3.0	3.9	4.5	3.5	4.1	89.0	2.5	2.1	2.4
Nomura Securities, Inc.	1.4	4.5 H	1.5	na	na	na	na	1.6	2.1	2.5	3.0	4.0	4.5	na	4.0	na	2.7	2.0	3.8
RBC Capital Markets	1.4	na	na	na	na	na	na	1.9 H	2.3 H	2.7 H	3.2	na	na	na	na	na	3.4	2.7	2.1
J.P. Morgan Chase	1.4	na	1.4	na	na	na	na	1.6	2.0	2.4	2.9	na	na	na	na	na	2.5	2.8	3.9
BNP Paribas Americas	1.4	na	1.4	na	na	na	na	1.6	2.0	2.3 L	na	na	na	na	na	na	3.0	na	3.2
Barclays Capital	1.4	4.5 H	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.5	2.9	3.7
Georgia State University	1.3	4.3	na	na	1.2	1.4	1.6 H	1.6	2.0	2.4	3.0	3.9	4.6	na	4.1	na	3.5	2.4	2.4
RidgeWorth Investments	1.3	4.3	1.5	1.3	1.2	1.3	1.4	1.7	1.9 L	2.3 L	2.8 L	3.7	4.4	3.4	3.9 L	88.0	2.5	2.0	1.5 L
Goldman Sachs & Co.	1.3	na	1.5	na	1.2	na	na	1.6	2.1	2.5	2.9	na	na	na	4.1	na	2.6	2.2	3.0
Swiss Re	1.3	4.4	1.5	1.3	1.2	1.3	1.4	1.6	2.1	2.5	3.0	3.9	4.7 H	na	4.3 H	na	2.7	3.5 H	4.5
AIG	1.2 L	4.3	na	na	1.2	1.3	1.5	1.6	2.1	2.4	4.0 H	na	4.4	na	4.1	na	2.6	1.7	2.8
Wells Capital Management	1.2 L	4.3	1.5	1.2 L	1.3 H	1.4	1.6 H	1.7	2.1	2.4	2.9	3.6	4.3 L	3.8 H	4.0	88.9	2.9	2.4	3.3
GLC Financial Economics	1.2 L	4.3	1.4	1.2 L	1.2	1.3	1.4	1.6	2.0	2.5	3.1	4.0 H	4.6	3.6	4.2	88.1	2.9	1.7	3.0
Regions Financial Corporation	1.2 L	4.3	1.5	1.3	1.2	1.4	1.5	1.7	2.1	2.4	2.9	3.9	4.6	3.7	4.1	89.1	3.0	1.8	1.8
Economist Intelligence Unit	1.2 L	4.3	1.3 L	1.2 L	1.2	1.4	1.5	1.7	2.1	2.4	2.9	na	na	na	3.9 L	na	2.6	na	2.3
BMO Capital Markets	1.2 L	4.3	1.5	na	1.2	1.4	1.5	1.7	2.1	2.4	2.9	na	na	na	3.9 L	89.4	2.9	1.7	3.3
Action Economics	1.2 L	4.3	1.5	1.2 L	1.3 H	1.4	1.5	1.8	2.1	2.4	2.9	3.6 L	4.3 L	3.6	3.9 L	88.3	3.0	2.2	3.8
Cycledata Corp.	1.2 L	4.3	1.4	1.2 L	1.2	1.4	1.6 H	1.7	2.0	2.4	2.8	3.7	4.6	3.4	3.9 L	88.0	2.9	1.9	2.1
Chmura Economics & Analytics	1.2 L	4.3	1.4	1.2 L	1.2	1.4	1.5	1.6	2.0	2.4	2.9	3.9	na	na	4.0	92.2 H	2.5	2.1	2.1
Nat'l Assn. of Realtors	1.2 L	4.3	1.4	1.2 L	1.2	1.3	1.5	1.6	2.0	2.4	2.9	3.7	4.4	3.6	4.0	na	2.5	1.9	2.2
Naroff Economic Advisors	1.2 L	4.3	1.3 L	1.3	1.2	1.3	1.5	1.6	2.0	2.4	2.9	4.0	4.6	3.4	4.0	89.2	2.5	2.0	2.2
MacroFin Analytics	1.2 L	4.3	1.4	1.2 L	1.2	1.4	1.4	1.6	2.1	2.4	2.9	3.7	4.3 L	3.6	4.0	89.2	2.7	1.8	2.4
Societe Generale	1.2 L	4.3	na	na	na	na	na	1.6	2.1	2.4	2.9	na	na	na	na	na	2.1 L	2.2	2.9
Wells Fargo	1.2 L	4.3	1.4	1.2 L	1.2	1.3	1.5	1.7	2.1	2.3	2.9	3.6 L	4.3 L	3.5	3.9 L	89.0	2.4	2.2	3.0
Daiwa Capital Markets America	1.2 L	4.3	1.4	1.2 L	1.2	1.3	1.5	1.7	2.1	2.4	2.9	na	na	na	4.0	89.0	2.8	2.5	3.2
RDQ Economics	1.2 L	4.3	1.4	1.2 L	1.1 L	1.3	1.5	1.7	2.1	2.4	2.9	3.7	4.3 L	3.5	4.1	89.1	2.6	2.1	3.5
Amherst Pierpont Securities	1.2 L	4.3	1.4	1.2 L	1.2	1.4	1.5	1.7	2.1	2.4	2.8 L	3.6 L	4.3 L	3.6	4.0	89.1	3.6 H	2.2	3.7
NatWest Markets	1.2 L	4.3	1.4	1.2 L	1.2	1.3	1.5	1.6	1.9 L	2.3 L	2.8 L	3.7	4.3 L	3.4	3.9 L	90.0	2.7	2.5	3.9
DePrince & Associates	1.2 L	4.3	1.5	1.2 L	1.2	1.4	1.5	1.7	2.0	2.4	2.9	3.6 L	4.3 L	3.6	4.0	88.0	2.5	2.1	2.5
Fannie Mae	1.2 L	4.3	na	na	1.2	1.4	1.5	1.6	2.0	2.4	2.8 L	na	na	na	3.9 L	na	2.5	1.7	2.8
Moody's Analytics	1.2 L	4.3	1.4	1.2 L	1.1 L	1.2 L	1.5	1.7	2.1	2.5	3.2	3.9	4.7 H	3.3 L	4.1	na	2.7	0.9 L	3.0
PNC Financial Services Corp.	1.2 L	4.3	1.5	na	1.2	1.3	1.5	1.7	2.1	2.4	3.0	na	4.4	3.6	4.0	87.2	3.1	2.1	1.9
Comerica Bank	1.2 L	4.3	1.4	na	1.2	1.3	1.5	1.6	2.0	2.4	2.8 L	na	na	na	4.0	na	3.1	1.9	2.4
DS Economics	1.2 L	4.3	1.4	1.3	1.1 L	1.3	1.4	1.6	2.1	2.4	2.9	3.8	4.4	3.3 L	4.1	87.3	2.5	1.5	2.8
Loomis, Sayles & Company	1.2 L	4.3	1.4	1.2 L	1.1 L	1.2 L	1.3 L	1.3 L	2.0	2.4	2.8 L	3.8	4.5	3.4	4.0	89.4	2.6	1.5	3.1
The Northern Trust Company	1.2 L	4.3	1.3 L	1.2 L	1.2	1.4	1.5	1.7	2.0	2.4	2.9	3.6 L	4.3 L	3.5	4.0	na	2.7	3.2	3.3
High Frequency Economics	1.2 L	4.3	na	na	1.2	1.4	1.6 H	1.9 H	2.2	2.5	3.0	na	na	na	na	na	2.5	2.7	2.7
Stone Harbor Investment Partners	1.2 L	4.3	1.3 L	1.3	1.1 L	1.2 L	1.4	1.5	2.0	2.3 L	2.9	3.7	4.3 L	na	4.0	87.0 L	2.7	1.9	2.9
Oxford Economics	1.2 L	4.2 L	1.3 L	na	1.1 L	1.2 L	1.3 L	1.4	2.0	2.4	3.0	na	na	na	4.0	88.5	2.8	2.9	4.0
S&P Global	1.2 L	4.4	1.5	na	1.1 L	1.2 L	1.4	1.5	1.9 L	2.3 L	2.9	na	na	na	4.0	87.4	2.8	2.9	5.6 H
Moody's Capital Markets Group	1.2 L	4.3	1.4	1.2 L	1.2	1.4	1.6 H	1.7	2.1	2.4	2.8 L	3.7	4.3 L	3.3 L	4.0	89.1	2.7	2.1	3.6
MUFG Union Bank	1.2 L	4.3	1.4	1.2 L	1.1 L	1.2 L	1.5	1.6	2.0	2.3 L	2.9	3.7	4.4	3.6	3.9 L	88.0	2.8	2.0	3.4
December Consensus	**1.2**	**4.3**	**1.4**	**1.2**	**1.2**	**1.3**	**1.5**	**1.6**	**2.0**	**2.4**	**2.9**	**3.8**	**4.4**	**3.5**	**4.0**	**88.7**	**2.7**	**2.2**	**3.0**
Top 10 Avg.	1.4	4.4	1.5	1.3	1.3	1.4	1.6	1.7	2.1	2.5	3.1	3.9	4.6	3.6	4.1	89.6	3.2	2.9	4.1
Bottom 10 Avg.	1.2	4.3	1.3	1.2	1.1	1.2	1.4	1.5	2.0	2.3	2.8	3.6	4.3	3.4	3.9	87.7	2.5	1.6	2.0
November Consensus	1.2	4.3	1.4	1.2	1.2	1.3	1.4	1.6	2.0	2.4	3.0	3.8	4.5	3.5	4.0	88.4	2.7	2.0	2.6
Number of Forecasts Changed From A Month Ago:																			
Down	5	6	9	10	5	6	3	5	5	16	24	16	17	13	19	10	10	10	5
Same	28	27	13	8	11	6	8	9	9	15	9	5	6	6	10	4	12	11	11
Up	10	6	13	8	21	23	24	28	28	11	8	5	4	4	7	11	21	20	26
Diffusion Index	56 %	50 %	56 %	46 %	72 %	74 %	80 %	77 %	77 %	44 %	30 %	29 %	26 %	30 %	33 %	52 %	63 %	62 %	75 %

First Quarter 2018

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter															Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term				Long-Term							
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Nomura Securities, Inc.	1.7 H	4.8 H	1.7	na	na	na	na	1.7	2.2	2.6	3.1	4.1	4.6	na	4.2	na	2.3	2.0	2.3
RBC Capital Markets	1.6	na	na	na	na	na	na	2.1 H	2.5	2.9 H	3.3	na	na	na	na	na	2.1	1.4 L	1.8
J.P. Morgan Chase	1.6	na	1.7	na	na	na	na	1.8	2.2	2.5	2.9	na	na	na	na	na	2.0	2.2	2.5
BNP Paribas Americas	1.6	na	1.5	na	na	na	na	1.6	2.0 L	2.3 L	na	na	na	na	na	na	2.0	na	1.6
Scotiabank Group	1.5	4.5	na	na	1.4	na	na	1.8	2.2	2.5	3.0	na	na	na	na	na	2.3	1.8	1.9
Daiwa Capital Markets America	1.5	4.7	1.7	1.5 H	1.5 H	1.6	1.8	1.9	2.3	2.5	2.9	na	na	na	4.1	89.0	2.6	2.0	2.1
Goldman Sachs & Co.	1.5	na	1.8 H	na	1.4	na	na	1.9	2.4	2.7	3.1	na	na	na	4.2	na	2.3	2.3	2.8
NatWest Markets	1.5	4.6	1.8 H	1.5 H	1.5 H	1.7 H	1.9 H	1.9	2.2	2.4	2.9	3.7 L	4.3 L	3.5	4.1	91.0	2.5	2.1	2.7
Action Economics	1.5	4.6	1.6	1.5 H	1.5 H	1.6	1.8	1.9	2.3	2.6	3.1	3.8	4.5	3.7	4.0 L	88.8	2.7	1.9	2.7
Amherst Pierpont Securities	1.5	4.6	1.7	1.5 H	1.5 H	1.6	1.8	1.9	2.3	2.7	3.1	3.9	4.6	3.8	4.3	90.3	2.9	2.4	2.7
Economist Intelligence Unit	1.5	4.5	1.5	1.4	1.4	1.6	1.8	1.9	2.3	2.6	3.1	na	na	na	4.1	na	2.0	na	2.2
DePrince & Assoc.	1.4 L	4.4 L	1.8 H	1.5 H	1.5 H	1.6	1.8	1.9	2.3	2.6	3.0	4.0	4.8	3.8	4.2	89.2	2.5	1.8	1.8
MacroFin Analytics	1.4 L	4.6	1.6	1.5 H	1.5 H	1.6	1.7	1.9	2.4	2.6	3.1	3.9	4.6	3.9	4.2	89.5	1.9	2.0	1.9
Regions Financial Corporation	1.4 L	4.4 L	1.6	1.4	1.4	1.5	1.7	1.9	2.3	2.6	3.1	4.1	4.7	3.8	4.2	89.3	1.8	1.9	2.2
Chase Wealth Management	1.4 L	4.5	1.6	1.5 H	1.4	1.5	1.6	1.7	2.1	2.5	3.1	4.0	4.5	3.5	4.1	88.8	2.0	2.0	2.1
Oxford Economics	1.4 L	4.5	1.7	na	1.4	1.5	1.5	1.7	2.2	2.6	3.1	na	na	na	4.1	88.5	2.8	1.4 L	1.4
High Frequency Economics	1.4 L	4.5	na	na	1.5 H	1.6	1.8	2.1 H	2.4	2.7	3.3	na	na	na	na	na	2.3	1.9	1.9
Naroff Economic Advisors	1.4 L	4.5	1.5	1.5 H	1.4	1.5	1.7	1.9	2.3	2.7	3.3	4.3	4.9	3.7	4.3	88.5	2.7	2.3	2.4
GLC Financial Economics	1.4 L	4.5	1.6	1.4	1.3	1.4	1.5	1.7	2.2	2.7	3.2	4.2	4.8	3.8	4.5 H	88.3	3.4 H	1.6	2.4
AIG	1.4 L	4.5	na	na	1.3	1.5	1.7	1.8	2.2	2.6	3.1	na	4.5	na	4.2	na	2.4	1.6	1.8
Moody's Analytics	1.4 L	4.5	1.6	1.4	1.2 L	1.4	1.7	2.0	2.5 H	2.9 H	3.7 H	4.4 H	5.4 H	3.6	4.5 H	na	2.9	2.9	2.0
Chmura Economics & Analytics	1.4 L	4.5	1.6	1.4	1.4	1.5	1.7	1.8	2.3	2.7	3.1	4.2	na	na	4.2	93.1 H	3.3	1.7	2.1
RidgeWorth Investments	1.4 L	4.5	1.6	1.4	1.3	1.4	1.5	1.9	2.1	2.5	2.9	3.9	4.6	3.7	4.1	90.0	2.0	2.0	1.6
DS Economics	1.4 L	4.5	1.4 L	1.3 L	1.3	1.5	1.7	1.9	2.3	2.6	3.1	3.8	4.5	3.4	4.2	88.4	1.8	1.7	1.8
Societe Generale	1.4 L	4.5	na	na	na	na	na	1.8	2.2	2.6	3.0	na	na	na	na	na	2.2	2.2	1.9
Wells Fargo	1.4 L	4.5	1.6	1.4	1.3	1.4	1.6	1.8	2.3	2.5	3.0	3.8	4.5	3.5	4.0 L	87.8	2.2	1.8	2.1
Cycledata Corp.	1.4 L	4.5	1.6	1.4	1.3	1.5	1.7	1.8	2.2	2.5	3.0	4.0	4.8	3.7	4.2	88.0	2.5	2.0	2.1
RDQ Economics	1.4 L	4.5	1.7	1.5 H	1.3	1.6	1.7	1.8	2.3	2.8	3.3	4.1	4.7	4.0	4.5	88.1	2.4	2.2	2.2
Nat'l Assn. of Realtors	1.4 L	4.5	1.6	1.4	1.4	1.5	1.6	1.8	2.2	2.6	3.1	3.9	4.6	3.8	4.2	na	2.6	2.0	2.5
MUFG Union Bank	1.4 L	4.5	1.6	1.5 H	1.4	1.5	1.8	1.8	2.3	2.7	3.2	4.0	4.6	3.9	4.4	86.0 L	2.9	1.8	3.1
Loomis, Sayles & Company	1.4 L	4.5	1.6	1.4	1.3	1.4	1.6	1.7	2.0 L	2.4	2.9	3.7 L	4.5	3.4	4.0 L	90.1	2.4	1.8	1.9
S&P Global	1.4 L	4.7	1.8	na	1.2 L	1.3 L	1.4 L	1.7	2.1	2.5	3.1	na	na	na	4.1	88.6	2.2	1.4 L	1.5
Fannie Mae	1.4 L	4.5	na	na	1.5 H	1.6	1.7	1.8	2.1	2.4	2.8 L	na	na	na	4.0 L	na	2.0	1.6	1.8
The Northern Trust Company	1.4 L	4.5	1.5	1.4	1.4	1.5	1.7	1.9	2.2	2.6	3.2	3.9	4.6	3.8	4.2	na	2.1	1.8	1.9
Wells Capital Management	1.4 L	4.5	1.6	1.4	1.5 H	1.7 H	1.9	2.0	2.4	2.7	3.2	4.0	4.7	4.1 H	4.3	89.0	2.8	1.9	2.3
Georgia State University	1.4 L	4.4 L	na	na	1.3	1.5	1.6	1.7	2.0 L	2.6	3.3	4.1	4.8	na	4.3	na	2.3	2.6	2.3
PNC Financial Services Corp.	1.4 L	4.5	1.7	na	1.4	1.6	1.6	1.8	2.2	2.6	3.2	na	4.7	3.6	4.1	87.4	2.4	2.1	2.4
Comerica Bank	1.4 L	4.5	1.6	na	1.4	1.5	1.6	1.8	2.2	2.6	3.0	na	na	na	4.2	na	2.9	2.1	2.4
BMO Capital Markets	1.4 L	4.5	1.6	na	1.3	1.5	1.7	1.9	2.2	2.5	2.9	na	na	na	4.0 L	90.4	1.9	2.4	2.8
Swiss Re	1.4 L	4.5	1.6	1.5 H	1.4	1.5	1.6	1.8	2.3	2.7	3.2	4.3	5.1	na	4.5 H	na	1.7 L	3.8 H	3.8 H
Moody's Capital Markets Group	1.4 L	4.5	1.5	1.3 L	1.5 H	1.6	1.7	1.8	2.2	2.4	2.8 L	3.7 L	4.3 L	3.3 L	4.1	89.6	3.0	1.9	0.9 L
Barclays Capital	1.4 L	4.5	1.7	na	na	na	na	1.9	2.1	2.4	2.9	na	na	na	na	na	2.0	2.2	2.3
Stone Harbor Investment Partners	1.4 L	4.5	1.5	1.5 H	1.3	1.4	1.5	1.6 L	2.2	2.5	3.0	3.9	4.5	na	4.3	88.0	2.8	1.7	2.2
December Consensus	**1.4**	**4.5**	**1.6**	**1.4**	**1.4**	**1.5**	**1.7**	**1.8**	**2.2**	**2.6**	**3.1**	**4.0**	**4.6**	**3.7**	**4.2**	**89.0**	**2.4**	**2.0**	**2.2**
Top 10 Avg.	1.5	4.6	1.7	1.5	1.5	1.6	1.8	2.0	2.4	2.7	3.3	4.2	4.9	3.9	4.4	90.2	3.0	2.5	2.8
Bottom 10 Avg.	1.4	4.5	1.5	1.4	1.3	1.4	1.5	1.7	2.1	2.4	2.9	3.8	4.5	3.5	4.0	87.9	1.9	1.6	1.6
November Consensus	1.4	4.5	1.6	1.4	1.3	1.5	1.6	1.8	2.2	2.6	3.1	4.0	4.7	3.7	4.2	88.8	2.4	1.9	2.0
Number of Forecasts Changed From A Month Ago:																			
Down	2	4	6	6	1	2	3	3	6	12	22	14	17	15	15	8	11	4	6
Same	35	32	19	15	21	14	15	17	16	20	13	9	6	4	13	5	19	17	22
Up	6	3	11	5	15	19	17	23	21	11	7	3	4	3	8	12	13	20	15
Diffusion Index	55 %	49 %	57 %	48 %	69 %	74 %	70 %	73 %	67 %	49 %	32 %	29 %	26 %	23 %	40 %	58 %	52 %	70 %	60 %

Second Quarter 2018

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter															Avg. For	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term				Long-Term				Qtr.			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	A.	B.	C.	D.
	Federal Funds Rate	Prime Bank Rate	LIBOR Rate 3-Mo.	Com. Paper 1-Mo.	Treas. Bills 3-Mo.	Treas. Bills 6-Mo.	Treas. Bills 1-Yr.	Treas. Notes 2-Yr.	Treas. Notes 5-Yr.	Treas. Notes 10-Yr.	Treas. Bond 30-Yr.	Aaa Corp. Bond	Baa Corp. Bond	State & Local Bonds	Home Mtg. Rate	Fed's Major Currency $ Index	Real GDP	GDP Price Index	Cons. Price Index
RBC Capital Markets	1.9 H	na	na	na	na	na	na	2.4 H	2.7	3.0	3.5	na	na	na	na	na	3.0	1.6	2.1
J.P. Morgan Chase	1.9 H	na	1.9	na	na	na	na	2.0	2.3	2.5	2.9	na	na	na	na	na	2.0	2.1	2.2
BNP Paribas Americas	1.9	na	1.7	na	na	na	na	1.7 L	2.1 L	2.5	na	na	na	na	na	na	4.0	na	1.3
Goldman Sachs & Co.	1.8	na	2.1 H	na	1.7	na	na	2.1	2.5	2.8	3.1	na	na	na	4.3	na	2.8	1.8	1.9
Scotiabank Group	1.8	4.8	na	na	1.6	na	na	1.9	2.2	2.6	3.0	na	na	na	na	na	2.0	1.8	2.2
Daiwa Capital Markets America	1.8	4.9 H	2.0	1.8 H	1.7	1.9	2.0	2.1	2.5	2.7	3.1	na	na	na	4.3	89.0	2.6	2.2	2.2
NatWest Markets	1.7	4.8	2.1 H	1.8 H	1.8 H	2.0 H	2.2 H	2.1	2.4	2.6	3.1	3.9	4.5	3.7	4.4	92.0	2.7	1.4	0.5 L
Regions Financial Corporation	1.7	4.7	1.9	1.6	1.6	1.7	1.9	2.1	2.4	2.7	3.3	3.4 L	4.9	4.0	4.4	89.6	2.2	2.0	1.9
MacroFin Analytics	1.7	4.8	1.9	1.7	1.7	1.9	2.0	2.2	2.6	2.9	3.4	4.2	4.9	4.2	4.5	90.0	2.0	2.2	2.0
Moody's Analytics	1.7	4.8	1.9	1.7	1.5	1.6	2.0	2.3	2.8 H	3.2 H	4.0 H	4.8 H	5.7 H	3.8	4.7	na	3.3	2.6	2.1
Action Economics	1.7	4.8	1.8	1.7	1.8 H	1.8	1.9	2.1	2.4	2.7	3.2	3.9	4.5	3.8	4.2	89.0	2.8	2.7 H	2.2
RDQ Economics	1.7	4.8	2.0	1.8 H	1.6	1.9	2.1	2.2	2.7	3.1	3.6	4.5	5.1	4.3	4.8 H	89.1	2.1	2.2	2.3
Nat'l Assn. of Realtors	1.7	4.7	1.9	1.7	1.6	1.7	1.8	2.0	2.4	2.8	3.4	4.3	5.0	4.1	4.4	na	3.0	2.1	2.5
Amherst Pierpont Securities	1.7	4.8	1.9	1.7	1.7	1.9	2.1	2.2	2.6	2.9	3.4	4.1	4.9	4.1	4.5	91.5	3.1	2.3	2.7 H
Societe Generale	1.7	4.8	na	na	na	na	na	2.0	2.2	2.6	3.1	na	na	na	na	na	1.9 L	1.7	0.5 L
DS Economics	1.7	4.8	1.5 L	1.4 L	1.5	1.8	2.0	2.1	2.5	2.8	3.3	3.9	4.7	3.6	4.3	89.3	2.1	1.7	1.3
DePrince & Assoc.	1.7	4.7	2.0	1.8	1.7	1.8	2.0	2.2	2.5	2.8	3.1	4.4	5.3	4.2	4.5	89.6	2.6	2.0	2.2
Oxford Economics	1.7	4.8	1.9	na	1.6	1.7	1.8	1.9	2.3	2.6	3.2	na	na	na	4.1	88.5	2.2	1.5	1.5
High Frequency Economics	1.7	4.8	na	na	1.7	1.9	2.1	2.2	2.5	2.8	3.4	na	na	na	na	na	2.8	2.0	2.0
Nomura Securities, Inc.	1.7	4.8	1.7	na	na	na	na	1.9	2.3	2.7	3.2	4.2	4.7	na	4.3	na	2.5	1.9	1.1
Chmura Economics & Analytics	1.7	4.8	1.9	1.7	1.6	1.8	1.9	2.0	2.5	2.9	3.4	4.5	na	na	4.5	92.5 H	3.2	1.8	2.1
Economist Intelligence Unit	1.7	4.7	1.7	1.7	1.6	1.8	2.0	2.1	2.5	2.8	3.3	na	na	na	4.3	na	2.8	na	2.2
Chase Wealth Management	1.7	4.8	1.8	1.7	1.6	1.7	1.9	1.9	2.3	2.7	3.3	4.2	4.7	3.8	4.3	88.5	2.2	2.0	2.1
Naroff Economic Advisors	1.7	4.8	1.7	1.8 H	1.8 H	1.9	2.0	2.2	2.5	3.0	3.6	4.5	5.2	4.0	4.5	86.3	3.2	2.6	2.7
Barclays	1.6	4.8	1.8	na	na	na	na	2.0	2.2	2.5	2.9	na	na	na	na	na	2.0	1.8	1.6
Stone Harbor Investment Partners	1.6	4.8	1.8	1.6	1.5	1.6	1.7	1.8	2.3	2.7	3.2	4.1	4.7	na	4.5	86.0	2.5	2.2	2.3
Cycledata Corp.	1.6	4.7	1.8	1.6	1.5	1.7	1.8	2.0	2.4	2.8	3.3	4.3	5.1	4.0	4.5	88.0	2.5	2.1	2.2
MUFG Union Bank	1.6	4.8	1.9	1.7	1.6	1.7	2.1	2.0	2.4	2.8	3.4	4.2	4.8	4.0	4.5	85.0 L	3.0	2.5	2.6
Swiss Re	1.5	4.6	1.8	1.6	1.5	1.6	1.7	1.9	2.4	2.8	3.5	4.5	5.3	na	4.7	na	2.0	-0.3 L	0.7
AIG	1.5	4.6	na	na	1.4	1.7	1.9	2.1	2.5	2.7	3.3	na	4.7	na	4.3	na	2.1	1.8	1.3
RidgeWorth Investments	1.5	4.6	1.7	1.5	1.4	1.5	1.6	2.0	2.1 L	2.5	3.1	3.9	4.6	3.8	4.2	91.0	2.4	2.1	1.8
S&P Global	1.5	4.9	2.0	na	1.4	1.5	1.7	1.8	2.1 L	2.5	3.1	na	na	na	4.2	90.1	2.3	1.7	1.2
BMO Capital Markets	1.5	4.6	1.8	na	1.4	1.6	1.9	2.1	2.3	2.5	3.0	na	na	na	4.1	90.9	2.2	2.0	2.1
Wells Capital Management	1.5	4.6	1.7	1.6	1.7	1.8	2.1	2.1	2.7	3.2 H	3.9	4.7	5.4	4.9 H	4.8	89.4	2.4	2.0	2.2
The Northern Trust Company	1.4 L	4.6	1.7	1.4 L	1.5	1.6	1.7	2.0	2.4	2.9	3.6	4.3	5.1	4.2	4.5	na	2.1	1.8	1.9
Fannie Mae	1.4 L	4.5	na	na	1.7	1.7	1.8	1.8	2.2	2.4 L	2.8 L	na	na	na	4.0 L	na	2.1	1.8	1.3
Loomis, Sayles & Company	1.4 L	4.5	1.7	1.4 L	1.4	1.5	1.7	1.9	2.1 L	2.4 L	3.0	3.8	4.5	3.4	4.0 L	90.1	2.2	1.7	1.9
Comerica Bank	1.4 L	4.5	1.7	na	1.3 L	1.5	1.6	1.8	2.2	2.7	3.1	na	na	na	4.3	na	2.9	2.0	2.0
PNC Financial Services Corp.	1.4 L	4.5	1.8	na	1.5	1.7	1.7	1.9	2.2	2.7	3.3	na	4.7	3.6	4.2	87.7	2.6	2.1	2.1
Moody's Capital Markets Group	1.4 L	4.5	1.7	1.4 L	1.5	1.6	1.8	1.9	2.2	2.5	2.8	3.6	4.4 L	3.3 L	4.1	89.8	4.4 H	1.8	1.3
GLC Financial Economics	1.4 L	4.5	1.6	1.4 L	1.3 L	1.4 L	1.5 L	1.7 L	2.2	2.8	3.3	4.4	5.1	4.0	4.7	88.0	3.0	2.2	2.4
Wells Fargo	1.4 L	4.5	1.7	1.5	1.4	1.5	1.7	1.9	2.4	2.6	3.1	3.9	4.6	3.6	4.1	86.5	2.6	1.8	2.1
Georgia State University	1.4 L	4.4 L	na	na	1.4	1.6	1.8	1.9	2.2	2.8	3.5	4.4	5.1	na	4.5	na	2.0	2.6	2.2
December Consensus	**1.6**	**4.7**	**1.8**	**1.6**	**1.6**	**1.7**	**1.9**	**2.0**	**2.4**	**2.7**	**3.3**	**4.2**	**4.9**	**3.9**	**4.4**	**89.1**	**2.6**	**1.9**	**1.9**
Top 10 Avg.	1.8	4.8	2.0	1.7	1.7	1.9	2.1	2.2	2.6	3.0	3.6	4.5	5.2	4.2	4.6	90.8	3.3	2.4	2.4
Bottom 10 Avg.	1.4	4.5	1.6	1.5	1.4	1.5	1.7	1.8	2.2	2.5	3.0	3.9	4.6	3.6	4.1	87.4	2.0	1.5	1.1
November Consensus	1.6	4.7	1.8	1.6	1.5	1.7	1.8	1.9	2.3	2.7	3.3	4.2	4.9	3.9	4.4	89.0	2.5	2.0	2.0
Number of Forecasts Changed From A Month Ago:																			
Down	3	3	6	7	4	3	4	3	4	7	18	10	12	11	15	9	10	11	18
Same	35	33	21	15	22	18	17	20	20	26	17	9	9	7	14	6	16	20	19
Up	5	3	9	4	11	14	14	20	19	10	7	7	5	4	7	10	17	10	6
Diffusion Index	52 %	50 %	54 %	44 %	59 %	66 %	64 %	70 %	67 %	53 %	37 %	44 %	37 %	34 %	39 %	52 %	58 %	49 %	36 %

Third Quarter 2018

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter															Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term				Long-Term							
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
J.P. Morgan Chase	2.1 H	na	2.2	na	na	na	na	2.2	2.4	2.6	2.9	na	na	na	na	na	1.8	2.1	2.2
RBC Capital Markets	2.1 H	na	na	na	na	na	na	2.6 H	2.9	3.2	3.6	na	na	na	na	na	2.8	2.4	2.2
BNP Paribas Americas	2.1 H	na	1.8	na	na	na	na	1.8 L	2.2 L	2.6	na	na	na	na	na	na	3.3	na	2.4
Goldman Sachs	2.0	na	2.3	na	1.9	na	na	2.4	2.7	2.9	3.2	na	na	na	4.4	na	2.3	1.9	2.0
Daiwa Capital Markets America	2.0	5.2 H	2.2	2.0	2.0	2.1	2.3	2.3	2.7	2.9	3.2	na	na	na	4.5	90.0	2.4	2.3	2.3
NatWest Markets	2.0	5.1	2.5 H	2.0	2.1 H	2.3 H	2.5 H	2.4	2.5	2.7	3.3	4.0	4.6	3.8	4.5	93.0 H	2.8	2.0	1.8
Moody's Analytics	2.0	5.1	2.1	2.0	1.8	1.9	2.3	2.6 H	3.1 H	3.4 H	4.2 H	5.0 H	5.9 H	4.0	4.9	na	2.5	2.8	2.6
Action Economics	2.0	5.1	2.1	2.0	2.0	2.0	2.1	2.2	2.5	2.8	3.2	4.0	4.7	3.9	4.3	88.9	2.7	2.4	2.4
MacroFin Analytics	1.9	5.1	2.1	2.0	1.9	2.1	2.2	2.4	2.9	3.1	3.6	4.4	5.1	4.4 H	4.7	90.5	2.2	2.2	2.3
Amherst Pierpont Securities	1.9	5.1	2.2	2.0	2.0	2.1	2.3	2.4	2.8	3.2	3.7	4.3	5.1	4.4 H	4.8	92.5	3.0	2.4	2.9
Regions Financial Corporation	1.9	4.9	2.0	1.9	1.8	1.9	2.1	2.2	2.6	2.9	3.5	4.5	5.2	4.2	4.6	89.4	2.5	2.1	2.1
High Frequency Economics	1.9	5.0	na	na	2.0	2.1	2.3	2.3	2.6	2.9	3.5	na	na	na	na	na	2.4	2.6	2.6
Chmura Economics & Analytics	1.9	5.0	2.2	1.9	1.8	2.0	2.1	2.2	2.7	3.1	3.7	4.7	na	na	4.7	91.6	3.3 H	1.9	1.9
Nomura Securities, Inc.	1.9	5.0	2.0	na	na	na	na	1.9	2.3	2.8	3.3	4.3	4.8	na	4.5	na	2.2	2.1	2.3
DePrince & Associates	1.9	4.9	2.2	2.0	1.9	2.0	2.2	2.4	2.7	3.0	3.3	4.7	5.7	4.4 H	4.7	90.0	2.7	2.0	2.2
Nat'l Assn. of Realtors	1.9	4.9	2.1	1.9	1.7	1.8	2.0	2.2	2.6	3.1	3.5	4.4	5.1	4.2	4.5	na	2.6	2.1	2.4
RDQ Economics	1.9	5.0	2.3	2.0	2.0	2.3 H	2.4	2.5	2.9	3.3	3.7	4.7	5.4	4.4 H	5.0	90.0	2.0	2.3	2.4
DS Economics	1.9	5.0	1.5 L	1.4 L	1.7	2.1	2.2	2.3	2.6	2.9	3.5	4.1	4.9	3.8	4.5	88.8	2.0	2.0	1.8
Oxford Economics	1.9	5.0	2.1	na	1.9	1.9	2.0	2.1	2.4	2.7	3.3	na	na	na	4.2	88.5	2.1	1.4 L	1.6
Naroff Economic Advisors	1.9	5.0	1.9	2.1 H	2.0	2.1	2.2	2.5	2.8	3.1	3.6	4.7	5.3	4.3	4.9	85.0	2.1	2.4	2.6
Societe Generale	1.9	5.0	na	na	na	na	na	2.2	2.4	2.8	3.2	na	na	na	na	na	2.0	1.9	1.3
MUFG Union Bank	1.9	5.0	2.1	1.9	1.9	2.0	2.3	2.2	2.6	3.0	3.6	4.3	5.1	4.1	4.6	85.0	3.1	2.1	2.7
Scotiabank Group	1.8	4.8	na	na	1.7	na	na	2.0	2.3	2.7	3.1	na	na	na	na	na	2.0	1.8	2.2
Swiss Re	1.8	4.9	2.0	1.8	1.8	1.9	2.0	2.2	2.6	3.0	3.7	4.6	5.6	na	4.8	na	1.9	1.5	2.5
Wells Capital Management	1.7	4.8	2.0	1.8	1.9	2.1	2.3	2.4	2.7	2.9	3.4	4.2	5.0	4.2	4.5	89.7	2.3	1.8	1.9
BMO Capital Markets	1.7	4.8	2.0	na	1.7	1.8	2.1	2.3	2.5	2.7	3.1	na	na	na	4.2	90.3	2.1	2.1	2.2
Wells Fargo	1.7	4.7	1.9	1.7	1.5 L	1.6 L	1.8	2.0	2.4	2.6	3.2	3.9	4.7	3.7	4.1 L	85.0	2.6	1.8	2.3
Economist Intelligence Unit	1.7	4.7	1.8	1.7	1.7	1.8	2.1	2.2	2.5	2.9	3.4	na	na	na	4.3	na	2.2	na	2.3
The Northern Trust Company	1.7	4.8	1.7	1.7	1.7	1.8	1.9	2.2	2.6	3.0	3.8	4.5	5.4	4.3	4.6	na	2.1	1.8	1.9
Georgia State University	1.7	4.7	na	na	1.6	1.8	2.1	2.2	2.4	3.0	3.6	4.5	5.3	na	4.7	na	2.2	2.2	2.0
Chase Wealth Management	1.7	4.8	1.9	1.7	1.6	1.8	1.9	2.0	2.4	2.7	3.3	4.2	4.8	3.8	4.3	88.2	2.2	2.2	2.2
AIG	1.7	4.7	na	na	1.5 L	1.9	2.1	2.3	2.6	2.9	3.5	na	4.9	na	4.4	na	2.0	1.7	1.9
RidgeWorth Investments	1.7	4.8	1.9	1.7	1.6	1.7	1.8	2.1	2.3	2.7	3.3	4.1	4.8	4.1	4.4	92.0	2.4	2.2	2.0
PNC Financial Services Corp.	1.7	4.8	2.0	na	1.7	1.8	1.9	2.0	2.3	2.8	3.4	na	4.8	3.6	4.3	87.7	2.3	2.1	2.3
S&P Global	1.6 L	5.0	2.1	na	1.6	1.7	1.8	2.0	2.3	2.6	3.2	na	na	na	4.2	90.3	2.5	1.5	1.1 L
Fannie Mae	1.6 L	4.8	na	na	1.8	1.8	1.8	1.9	2.2 L	2.4 L	2.8 L	na	na	na	4.1 L	na	2.0	2.1	1.9
Loomis, Sayles & Company	1.6 L	4.7	1.9	1.6	1.6	1.7	1.9	2.0	2.3	2.5	3.0	3.9	4.6	3.5	4.1 L	90.1	2.2	2.0	2.0
Comerica Bank	1.6 L	4.7	1.9	na	1.5 L	1.6	1.8	2.0	2.5	2.9	3.4	na	na	na	4.6	na	2.6	2.0	2.0
Moody's Capital Markets Group	1.6 L	4.8	1.9	1.6	1.7	1.8	1.9	1.9	2.3	2.5	2.8 L	3.7 L	4.4 L	3.2 L	4.2	90.0	0.0 L	1.8	1.9
Barclays	1.6 L	4.8	1.9	na	na	na	na	2.1	2.3	2.5	2.9	na	na	na	na	na	2.0	2.0	1.9
GLC Financial Economics	1.6 L	4.6 L	1.9	1.7	1.6	1.6 L	1.7 L	1.9	2.5	3.2	3.7	5.0	5.7	4.4	5.3 H	88.2	2.4	3.1 H	3.3 H
Stone Harbor Investment Partners	1.6 L	4.8	1.7	1.7	1.6	1.7	1.7	1.8 L	2.4	2.7	3.2	4.1	4.7	na	4.5	84.0 L	2.4	2.1	2.0
Cycledata Corp.	1.6 L	4.7	1.8	1.6	1.5 L	1.7	1.8	2.0	2.4	2.8	3.3	4.3	5.1	4.0	4.5	88.0	2.4	2.2	2.3
December Consensus	**1.8**	**4.9**	**2.0**	**1.8**	**1.7**	**1.9**	**2.0**	**2.2**	**2.5**	**2.8**	**3.4**	**4.3**	**5.1**	**4.0**	**4.5**	**89.1**	**2.3**	**2.1**	**2.2**
Top 10 Avg.	2.0	5.1	2.2	2.0	2.0	2.1	2.3	2.4	2.8	3.2	3.7	4.7	5.5	4.3	4.9	91.0	2.9	2.5	2.6
Bottom 10 Avg.	1.6	4.7	1.8	1.6	1.5	1.7	1.8	1.9	2.3	2.6	3.0	4.0	4.7	3.7	4.2	86.8	1.8	1.7	1.7
November Consensus	1.8	4.9	2.0	1.8	1.7	1.9	2.0	2.1	2.5	2.8	3.4	4.4	5.1	4.1	4.5	89.0	2.4	2.1	2.2
Number of Forecasts Changed From A Month Ago:																			
Down	3	2	6	6	4	6	7	5	8	10	16	13	15	12	15	5	9	8	11
Same	33	33	22	15	19	16	13	20	20	23	20	9	7	6	15	10	22	22	25
Up	7	4	8	4	14	13	15	18	15	10	6	3	4	4	6	11	12	11	7
Diffusion Index	55 %	53 %	53 %	46 %	64 %	60 %	61 %	65 %	58 %	50 %	38 %	30 %	29 %	32 %	38 %	62 %	53 %	54 %	45 %

Fourth Quarter 2018

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter															Avg. For	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term				Long-Term							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	A.	B.	C.	D.
	Federal Funds Rate	Prime Bank Rate	LIBOR Rate 3-Mo.	Com. Paper 1-Mo.	Treas. Bills 3-Mo.	Treas. Bills 6-Mo.	Treas. Bills 1-Yr.	Treas. Notes 2-Yr.	Treas. Notes 5-Yr.	Treas. Notes 10-Yr.	Treas. Bond 30-Yr.	Aaa Corp. Bond	Baa Corp. Bond	State & Local Bonds	Home Mtg. Rate	Fed's Major Currency $ Index	Real GDP	GDP Price Index	Cons. Price Index
Moody's Analytics	2.5 H	5.6 H	2.6	2.4 H	2.2	2.3	2.7	2.9 H	3.4 H	3.7 H	4.4 H	5.3 H	6.2 H	4.2	5.2	na	2.4	3.2 H	2.8
RBC Capital Markets	2.4	na	na	na	na	na	na	2.7	3.0	3.4	3.8	na	na	na	na	na	2.7	1.9	1.8
J.P. Morgan Chase	2.4	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	1.8	2.1	2.2
Goldman Sachs & Co.	2.3	na	2.6	na	2.2	na	na	2.6	2.8	3.0	3.3	na	na	na	4.6	na	2.0	1.7	1.8
NatWest Markets	2.2	5.3	2.7 H	2.3	2.3	2.5	2.7	2.5	2.7	2.8	3.4	4.1	4.8	4.0	4.6	91.0	2.8	2.1	2.2
MacroFin Analytics	2.2	5.3	2.4	2.2	2.2	2.4	2.5	2.7	3.1	3.4	3.9	4.7	5.4	4.7 H	5.0	91.0	2.0	2.2	2.3
Naroff Economic Advisors	2.2	5.3	2.3	2.3	2.3	2.5	2.6	2.7	3.0	3.3	3.8	4.9	5.5	4.6	5.1	84.1	1.1 L	2.1	2.4
RDQ Economics	2.2	5.3	2.7 H	2.3	2.4	2.6	2.7	2.7	3.1	3.5	3.8	4.9	5.7	4.6	5.2	91.2	1.9	2.3	2.4
Amherst Pierpont Securities	2.2	5.3	2.4	2.2	2.2	2.4	2.5	2.6	3.1	3.4	3.9	4.7	5.5	4.7 H	5.1	93.0	2.9	2.4	3.0
High Frequency Economics	2.2	5.3	na	na	2.2	2.4	2.6	2.4	2.7	3.0	3.5	na	na	na	na	na	2.4	2.6	2.6
Regions Financial Corporation	2.2	5.2	2.2	2.0	2.0	2.1	2.2	2.4	2.8	3.1	3.7	4.6	5.4	4.3	4.7	89.2	2.2	2.0	2.2
Chmura Economics & Analytics	2.2	5.3	2.4	2.2	2.1	2.2	2.4	2.5	2.9	3.3	3.9	4.8	na	na	4.8	90.6	3.4 H	2.1	2.2
DS Economics	2.2	5.2	1.7 L	1.5 L	2.0	2.2	2.2	2.3	2.6	3.0	3.5	4.1	4.9	3.8	4.5	88.7	2.1	2.0	1.9
Daiwa Capital Markets America	2.2	5.3	2.3	2.1	2.1	2.2	2.4	2.5	2.8	3.0	3.3	na	na	na	4.7	90.0	2.4	2.3	2.3
Action Economics	2.1	5.3	2.3	2.1	2.2	2.2	2.3	2.4	2.6	2.9	3.3	4.1	4.8	3.9	4.4	89.0	2.4	2.4	2.4
BNP Paribas Americas	2.1	na	1.8	na	na	na	na	1.9 L	2.3 L	2.7	na	na	na	na	na	na	2.6	na	2.7
DePrince & Assoc.	2.1	5.1	2.4	2.2	2.1	2.2	2.4	2.6	2.9	3.2	3.4	5.0	6.0	4.7 H	4.9	90.3	2.6	2.2	2.4
MUFG Union Bank	2.1	5.3	2.4	2.2	2.2	2.3	2.6	2.5	2.8	3.2	3.7	4.4	5.2	4.2	4.8	84.0	3.3	2.1	2.8
Scotiabank Group	2.0	5.0	na	na	2.0	na	na	2.1	2.3 L	2.7	3.1	na	na	na	na	na	1.8	1.8	2.2
Nat'l Assn. of Realtors	2.0	5.0	2.2	2.0	1.9	2.0	2.2	2.4	2.8	3.2	3.7	4.7	5.3	4.3	4.6	na	2.6	2.1	2.3
Swiss Re	2.0	5.1	2.3	2.1	2.0	2.1	2.2	2.4	2.8	3.1	3.9	4.8	5.8	na	5.0	na	2.0	2.1	3.1 H
Wells Capital Management	2.0	5.1	2.2	2.1	2.2	2.4	2.5	2.6	2.8	3.0	3.3	4.2	5.0	4.1	4.5	89.9	2.2	2.1	2.2
Economist Intelligence Unit	2.0	5.0	2.0	2.0	1.9	2.0	2.2	2.3	2.7	3.0	3.5	na	na	na	4.5	na	2.1	na	2.2
BMO Capital Markets	2.0	5.1	2.2	na	1.9	2.0	2.3	2.5	2.7	2.8	3.2	na	na	na	4.4	89.6	1.9	2.1	2.3
The Northern Trust Company	1.9	5.1	1.9	1.9	2.0	2.1	2.2	2.5	2.9	3.3	4.0	4.9	5.8	4.6	4.9	na	2.1	1.9	2.0
PNC Financial Services Corp.	1.9	5.1	2.2	na	1.9	2.1	2.1	2.2	2.5	2.9	3.5	na	5.0	3.7	4.5	87.6	2.4	2.1	2.4
Nomura Securities, Inc.	1.9	5.0	2.1	na	na	na	na	2.0	2.5	2.8	3.3	4.3	4.8	na	4.5	na	2.2	2.0	2.7
Wells Fargo	1.9	5.0	2.0	1.9	1.7	1.8	2.0	2.1	2.5	2.7	3.3	4.0	4.8	3.8	4.2	83.5	2.6	1.3 L	1.4 L
Chase Wealth Management	1.9	5.0	2.1	1.9	1.8	2.0	2.1	2.2	2.6	3.0	3.5	4.4	5.0	4.0	4.5	88.0	2.0	2.1	2.1
Oxford Economics	1.9	5.0	2.2	2.3	2.5 H	2.7 H	3.3 H	na	na	na	na	na	na	na	4.3	88.6	2.2	1.8	2.0
Barclays Capital	1.9	5.0	2.2	na	na	na	na	2.1	2.3 L	2.5 L	2.9	na	na	na	na	na	2.0	2.1	2.1
Georgia State University	1.9	4.9	na	na	1.8	2.0	2.2	2.3	2.6	3.2	3.8	4.7	5.7	na	5.1	na	2.4	2.0	1.9
Stone Harbor Investment Partners	1.9	5.0	2.0	2.0	1.8	1.8	1.9	2.0	2.5	2.8	3.3	4.2	4.8	na	4.6	83.0 L	2.2	2.3	2.3
Societe Generale	1.8	5.0	na	na	na	na	na	2.3	2.5	2.7	3.1	na	na	na	na	na	1.8	2.0	2.0
AIG	1.7	4.8	na	na	1.6	2.0	2.3	2.5	2.8	3.0	3.6	na	5.0	na	4.5	na	2.1	1.8	1.9
RidgeWorth Investments	1.7	4.8	1.9	1.7	1.6	1.8	1.8	2.2	2.4	2.8	3.4	4.2	4.9	4.2	4.4	93.0 H	2.5	2.2	2.4
S&P Global	1.7	5.0	2.1	na	1.7	1.8	1.9	2.1	2.4	2.7	3.3	na	na	na	4.3	90.6	2.4	1.9	1.9
Fannie Mae	1.7	4.8	na	na	1.8	1.8	1.8	1.9 L	2.3 L	2.5 L	2.9	na	na	na	4.1 L	na	1.8	2.0	1.9
Loomis, Sayles & Company	1.7	4.8	2.0	1.7	1.6	1.8	2.0	2.2	2.3 L	2.6	3.0	4.0	4.7	3.6	4.2	90.1	2.1	2.0	2.0
Comerica Bank	1.7	4.8	1.9	na	1.6	1.7	1.8	2.1	2.5	2.9	3.4	na	na	na	4.7	na	2.7	2.0	2.0
Moody's Capital Markets Group	1.7	4.8	1.9	1.7	1.8	1.9	1.9	1.9 L	2.3 L	2.5 L	2.8 L	3.7 L	4.4 L	3.2 L	4.2	89.7	2.1	1.8	1.4 L
GLC Financial Economics	1.7	4.7 L	1.9	1.7	1.6	1.7 L	1.7 L	1.9 L	2.6	3.3	3.8	5.1	5.9	4.5	5.5 H	88.5	3.0	2.7	3.0
Cycledata Corp.	1.6 L	4.7 L	1.8	1.6	1.5 L	1.7 L	1.8	2.0	2.4	2.8	3.3	4.3	5.1	4.0	4.5	88.0	2.4	2.2	2.3
December Consensus	**2.0**	**5.1**	**2.2**	**2.0**	**2.0**	**2.1**	**2.3**	**2.3**	**2.7**	**3.0**	**3.5**	**4.5**	**5.2**	**4.2**	**4.6**	**88.9**	**2.3**	**2.1**	**2.2**
Top 10 Avg.	2.3	5.3	2.5	2.3	2.3	2.4	2.7	2.7	3.0	3.4	3.9	4.9	5.7	4.5	5.1	91.1	2.9	2.5	2.8
Bottom 10 Avg.	1.7	4.8	1.9	1.8	1.6	1.8	1.9	2.0	2.3	2.6	3.1	4.1	4.8	3.8	4.3	86.4	1.8	1.8	1.8
November Consensus	2.0	5.1	2.2	2.0	1.9	2.1	2.2	2.3	2.7	3.0	3.5	4.5	5.3	4.2	4.7	88.9	2.3	2.1	2.3
Number of Forecasts Changed From A Month Ago:																			
Down	3	3	5	7	6	7	5	6	8	9	15	11	14	9	15	7	10	9	10
Same	35	33	21	14	18	16	17	19	21	23	16	6	7	8	14	10	23	22	25
Up	5	3	8	5	13	12	13	14	10	7	7	8	5	5	7	9	10	10	8
Diffusion Index	52 %	50 %	54 %	46 %	59 %	57 %	61 %	60 %	53 %	47 %	39 %	44 %	33 %	41 %	39 %	54 %	50 %	51 %	48 %

First Quarter 2019

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter															Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term				Long-Term							
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Moody's Analytics	3.0 H	6.1 H	3.1 H	2.9 H	2.6	2.8	3.1 H	3.3 H	3.7 H	4.0 H	4.7 H	5.5 H	6.5 H	4.4	5.4	na	2.3	3.4	2.9
MacroFin Analytics	2.6	5.8	2.8	2.7	2.7 H	2.8 H	2.9	3.1	3.6	3.8	4.3	5.1	5.8	5.1 H	5.4	91.5	2.0	2.2	2.2
J.P. Morgan Chase	2.6	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	1.8	2.2	2.3
Goldman Sachs & Co.	2.5	na	2.8	na	2.4	na	na	2.8	3.0	3.1	3.4	na	na	na	4.7	na	1.5	1.8	1.9
NatWest Markets	2.5	5.6	2.9	2.5	2.6	2.8	3.0	2.7	2.9	3.0	3.5	4.3	5.0	4.0	4.8	89.0	2.5	2.2	2.0
Naroff Economic Advisors	2.5	5.5	2.6	2.6	2.6	2.8	3.0	3.0	3.3	3.6	4.1	5.1	5.8	4.8	5.3	83.0	0.5 L	2.0	1.9
Amherst Pierpont Securities	2.4	5.6	2.6	2.5	2.4	2.6	2.8	2.9	3.3	3.6	4.1	4.9	5.8	4.9	5.3	93.5	2.5	2.4	3.2
Chmura Economics & Analytics	2.4	5.5	2.7	2.5	2.3	2.5	2.6	2.7	3.1	3.4	4.1	4.9	na	na	5.0	89.6	3.4 H	2.1	2.3
DS Economics	2.3	5.4	1.7 L	1.5 L	2.1	2.5	2.7	2.8	3.0	3.2	3.8	4.3	5.2	3.9	4.7	88.6	1.8	2.5	2.4
DePrince & Assoc.	2.3	5.3	2.6	2.4	2.3	2.4	2.6	2.8	3.1	3.4	3.6	5.3	6.2	4.9	5.2	90.7	2.7	2.2	2.4
Regions Financial Corporation	2.3	5.3	2.3	2.2	2.1	2.3	2.4	2.5	2.9	3.2	3.8	4.8	5.5	4.4	4.9	88.9	2.0	1.8	2.1
Daiwa Capital Markets America	2.3	5.4	2.5	2.3	2.2	2.4	2.5	2.7	3.0	3.1	3.4	na	na	na	4.8	90.0	2.1	2.4	2.3
MUFG Union Bank	2.3	5.5	2.6	2.4	2.4	2.5	2.9	2.7	2.9	3.3	3.9	3.5 L	5.3	4.2	4.9	83.0	2.9	2.3	3.0
Swiss Re	2.3	5.4	2.5	2.3	2.2	2.4	2.5	2.6	3.0	3.3	4.1	4.9	5.9	na	5.2	na	2.3	3.5 H	3.5 H
Wells Capital Management	2.2	5.3	2.5	2.4	2.5	2.6	2.7	2.8	3.0	3.1	3.3	4.2	5.1	4.0	4.6	90.0	2.4	2.0	2.3
Action Economics	2.2	5.3	2.5	2.2	2.3	2.3	2.5	2.6	2.7	2.9	3.4	4.2	4.8	3.9	4.5	89.2	2.3	2.0	2.4
BMO Capital Markets	2.2	5.3	2.5	na	2.1	2.2	2.5	2.7	2.9	3.0	3.4	na	na	na	4.6	89.0	1.9	2.2	2.4
Nat'l Assn. of Realtors	2.2	5.2	2.4	2.2	2.1	2.2	2.3	2.5	2.9	3.3	3.8	4.8	5.4	4.4	4.7	na	2.6	2.1	2.3
Economist Intelligence Unit	2.2	5.3	2.3	2.2	2.1	2.2	2.4	2.6	2.9	3.2	3.7	na	na	na	4.7	na	2.1	na	2.3
The Northern Trust Company	2.2	5.3	2.2	2.2	2.1	2.2	2.4	2.6	3.0	3.4	4.2	5.0	5.9	4.7	5.0	na	1.9	2.0	2.2
PNC Financial Services Corp.	2.2	5.3	2.4	na	2.1	2.3	2.3	2.4	2.6	3.0	3.6	na	5.1	3.7	4.6	87.5	2.2	2.1	2.4
Barclays	2.1	5.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.0	2.2	2.3
Oxford Economics	2.1	5.2	2.4	na	2.1	2.2	2.2	2.4	2.6	2.8	3.4	na	na	na	4.4	88.6	1.7	1.7 L	1.8 L
Societe Generale	2.0	5.3	na	na	na	na	na	2.1	2.3 L	2.6	3.0	na	na	na	na	na	1.7	1.9	1.8 L
Scotiabank Group	2.0	5.0	na	na	2.1	na	na	2.2	2.4	2.8	3.1	na	na	na	na	na	1.6	2.0	2.2
Georgia State University	2.0	5.0	na	na	1.9	2.1	2.3	2.4	2.7	3.3	3.8	4.8	5.9	na	5.2	na	2.3	2.2	2.2
Stone Harbor Investment Partners	2.0	5.1	2.2	2.1	1.9	2.0	2.0	2.1	2.6	2.9	3.3	4.3	4.9	na	4.7	82.0 L	2.7	2.3	2.4
S&P Global	2.0	5.1	2.3	na	1.9	2.1	2.1	2.3	2.5	2.7	3.3	na	na	na	4.3	90.4	1.6	1.9	1.9
Chase Wealth Management	1.9	5.0	2.1	1.9	1.8	2.0	2.1	2.2	2.6	3.0	3.5	4.4	5.0	4.0	4.6	88.0	1.8	2.2	2.0
Nomura Securities, Inc.	1.9	5.0	2.1	na	na	na	na	2.0	2.6	2.9	3.3	4.3	4.9	na	4.6	na	2.0	2.0	2.2
AIG	1.9	5.0	na	na	1.8	2.2	2.5	2.7	2.9	3.1	3.7	na	5.1	na	4.6	na	2.1	2.0	2.4
Loomis, Sayles & Company	1.9	5.0	2.2	1.9	1.8	2.0	2.2	2.3	2.5	2.8	3.0	4.1	4.9	3.8	4.4	90.1	1.9	2.5	2.0
Wells Fargo	1.9	5.0	2.1	2.0	1.8	1.9	2.1	2.2	2.6	2.8	3.5	4.1	4.9	3.9	4.2	82.0 L	2.4	2.0	2.2
RidgeWorth Investments	1.9	5.0	2.1	1.9	1.8	1.9	2.0	2.3	2.6	3.0	3.6	4.4	5.1	4.4	4.6	94.0 H	2.0	2.2	2.4
Comerica Bank	1.9	5.0	2.1	na	1.8	1.9	2.0	2.3	2.7	3.2	3.6	na	na	na	4.9	na	2.6	1.9	2.0
Fannie Mae	1.9	5.0	na	na	1.8	1.8	1.8 L	2.0	2.3 L	2.5	2.9	na	na	na	4.2	na	1.7	2.4	2.4
Moody's Capital Markets Group	1.9	5.0	2.2	1.9	1.9	2.0	1.9	1.9 L	2.3 L	2.4 L	2.7 L	3.6	4.4 L	3.1 L	4.1 L	89.2	1.4	1.9	1.8 L
GLC Financial Economics	1.8	4.8	2.0	1.8	1.7	1.8	1.9	2.1	2.7	3.4	3.9	5.1	5.9	4.7	5.6 H	88.8	2.2	1.9	2.6
Cycledata Corp.	1.6 L	4.7 L	1.8	1.6	1.5 L	1.7 L	1.8 L	2.0	2.4	2.8	3.3	4.3	5.1	4.0	4.5	88.0	2.4	2.2	2.3
December Consensus	**2.2**	**5.2**	**2.4**	**2.2**	**2.1**	**2.2**	**2.4**	**2.5**	**2.8**	**3.1**	**3.6**	**4.6**	**5.3**	**4.3**	**4.8**	**88.5**	**2.1**	**2.2**	**2.3**
Top 10 Avg.	2.5	5.6	2.7	2.5	2.5	2.6	2.8	2.9	3.2	3.5	4.1	5.1	5.9	4.7	5.2	90.9	2.7	2.6	2.7
Bottom 10 Avg.	1.9	4.9	2.0	1.9	1.8	1.9	2.0	2.1	2.4	2.7	3.1	4.1	4.9	3.8	4.4	85.9	1.5	1.9	1.9
November Consensus	2.1	5.2	2.4	2.2	2.1	2.2	2.4	2.5	2.8	3.1	3.6	4.6	5.4	4.3	4.8	88.4	2.1	2.2	2.3
Number of Forecasts Changed From A Month Ago:																			
Down	3	3	6	7	4	3	2	5	6	7	13	9	10	8	11	4	7	8	7
Same	34	31	21	14	19	19	20	20	22	24	18	11	10	8	14	9	26	23	27
Up	3	4	5	4	12	11	11	13	10	7	7	5	6	5	10	11	7	8	6
Diffusion Index	50 %	51 %	48 %	44 %	61 %	62 %	64 %	61 %	55 %	50 %	42 %	42 %	42 %	43 %	49 %	65 %	50 %	50 %	49 %

International Interest Rate And Foreign Exchange Rate Forecasts

United States

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			Fed's Major Currency $ Index		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	2.40	2.45	na	na	na	na
BMO Capital Markets	1.60	1.75	2.20	2.45	2.50	2.80	90.4	91.0	89.6
IHSMarkit	na	na	na	na	na	na	na	na	na
ING Financial Markets	1.60	1.90	2.10	2.70	2.80	2.90	na	na	na
Mizuho Research Institute	1.80	2.10	2.10	2.40	2.50	2.50	89.0	90.0	88.0
Moody's Analytics	na	na	na	2.86	3.15	3.74	na	na	na
Moody's Capital Markets	na	na	na	2.40	2.45	2.35	89.5	89.7	89.7
Nomura Securities	na	na	na	na	na	na	na	na	na
Oxford Economics	na	na	na	2.58	2.63	2.75	88.5	88.5	88.6
Scotiabank	na	na	na	2.50	2.60	2.70	na	na	na
Wells Fargo	1.65	1.90	2.15	2.57	2.66	2.78	na	na	na
December Consensus	**1.66**	**1.91**	**2.14**	**2.54**	**2.64**	**2.82**	**89.4**	**89.8**	**89.0**
High	1.80	2.10	2.20	2.86	3.15	3.74	90.4	91.0	89.7
Low	1.60	1.75	2.10	2.40	2.45	2.35	88.5	88.5	88.0
Last Months Avg.	1.60	1.71	2.02	2.46	2.57	2.76	88.4	88.4	87.3

Japan

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			USD/YEN		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	0.05	0.10	na	na	na	na
BMO Capital Markets	-0.05	-0.05	-0.05	0.05	0.05	0.10	115.0	116.0	117.0
IHSMarkit	na	na	na	na	na	na	114.9	115.6	117.3
ING Financial Markets	0.05	0.05	0.05	0.10	0.10	0.10	114.0	114.0	115.0
Mizuho Research Institute	0.06	0.06	0.06	0.05	0.05	0.05	114.0	115.0	115.0
Moody's Analytics	na	na	na	0.06	0.10	0.09	112.3	112.2	112.2
Moody's Capital Markets	na	na	na	0.06	0.01	0.06	112.5	112.8	112.7
Nomura Securities	na	na	na	na	na	na	120.0	120.0	114.0
Oxford Economics	na	na	na	0.07	0.07	0.07	113.2	113.6	115.0
Scotiabank	na	na	na	na	na	na	114.0	114.0	115.0
Wells Fargo	0.03	-0.01	0.01	0.05	0.07	0.12	na	na	na
December Consensus	**0.02**	**0.01**	**0.02**	**0.06**	**0.07**	**0.08**	**114.4**	**114.8**	**114.8**
High	0.06	0.06	0.06	0.10	0.10	0.12	120.0	120.0	117.3
Low	-0.05	-0.05	-0.05	0.05	0.01	0.05	112.3	112.2	112.2
Last Months Avg.	0.03	0.03	0.04	0.06	0.08	0.08	113.7	114.6	114.9

United Kingdom

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gilt Yields %			GBP/USD		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	1.45	1.50	na	na	na	na
BMO Capital Markets	0.65	0.65	0.90	1.55	1.65	1.85	1.31	1.30	1.32
IHSMarkit	na	na	na	na	na	na	1.28	1.28	1.32
ING Financial Markets	0.60	0.60	0.60	1.40	1.45	1.50	1.36	1.39	1.48
Mizuho Research Institute	0.55	0.60	0.80	1.50	1.55	1.70	na	na	na
Moody's Analytics	na	na	na	1.59	1.67	1.88	1.29	1.28	1.25
Moody's Capital Markets	na	na	na	1.35	1.40	1.35	1.32	1.30	1.30
Nomura Securities	na	na	na	na	na	na	1.40	1.42	1.45
Oxford Economics	na	na	na	1.61	1.72	1.94	1.36	1.37	1.38
Scotiabank	na	na	na	na	na	na	1.35	1.35	1.37
Wells Fargo	0.60	0.65	0.95	1.40	1.60	1.85	na	na	na
December Consensus	**0.60**	**0.63**	**0.81**	**1.48**	**1.57**	**1.72**	**1.33**	**1.34**	**1.36**
High	0.65	0.65	0.95	1.61	1.72	1.94	1.40	1.42	1.48
Low	0.55	0.60	0.60	1.35	1.40	1.35	1.28	1.28	1.25
Last Months Avg.	0.49	0.51	0.64	1.43	1.52	1.72	1.34	1.35	1.37

Switzerland

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			USD/CHF		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	na	na	na	1.00	0.99	na
BMO Capital Markets	na	na	na	na	na	na	na	na	na
IHSMarkit	na	na	na	na	na	na	1.00	1.00	0.98
ING Financial Markets	-0.70	-0.70	-0.60	-0.05	0.10	0.40	0.97	0.97	0.98
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Moody's Analytics	na	na	na	0.04	0.11	0.25	0.99	1.00	1.01
Moody's Capital Markets	na	na	na	-0.13	-0.08	-0.05	0.99	0.99	0.99
Nomura Securities	na	na	na	na	na	na	0.92	0.91	0.89
Oxford Economics	na	na	na	0.13	0.25	0.43	0.98	0.98	0.98
Scotiabank	na	na	na	na	na	na	na	na	na
Wells Fargo	na	na	na	na	na	na	na	na	na
December Consensus	**-0.70**	**-0.70**	**-0.60**	**0.00**	**0.10**	**0.26**	**0.98**	**0.98**	**0.97**
High	-0.70	-0.70	-0.60	0.13	0.25	0.43	1.00	1.00	1.01
Low	-0.70	-0.70	-0.60	-0.13	-0.08	-0.05	0.92	0.91	0.89
Last Months Avg.	-0.70	-0.70	-0.70	0.06	0.09	0.25	0.97	0.97	0.98

Canada

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			USD/CAD		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	na	na	na	1.25	1.23	na
BMO Capital Markets	na	na	na	2.05	2.15	2.50	1.31	1.32	1.31
IHSMarkit	na	na	na	na	na	na	1.25	1.26	1.27
ING Financial Markets	1.90	2.00	1.60	2.30	2.40	2.70	1.27	1.22	1.20
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Moody's Analytics	na	na	na	2.56	2.85	3.55	1.25	1.25	1.23
Moody's Capital Markets	na	na	na	2.00	2.05	1.95	1.29	1.29	1.29
Nomura Securities	na	na	na	na	na	na	1.21	1.19	1.16
Oxford Economics	na	na	na	2.36	2.48	2.73	1.29	1.29	1.29
Scotiabank	na	na	na	2.20	2.25	2.45	1.28	1.27	1.25
Wells Fargo	1.65	1.75	2.00	2.20	2.40	2.55	na	na	na
December Consensus	**1.78**	**1.88**	**1.80**	**2.24**	**2.37**	**2.63**	**1.27**	**1.26**	**1.25**
High	1.90	2.00	2.00	2.56	2.85	3.55	1.31	1.32	1.31
Low	1.65	1.75	1.60	2.00	2.05	1.95	1.21	1.19	1.16
Last Months Avg.	1.35	1.53	1.75	2.29	2.44	2.70	1.24	1.23	1.22

International Interest Rate And Foreign Exchange Rate Forecasts

Australia

	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			AUD/AUD		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	na	na	na	0.76	0.76	na
BMO Capital Markets	na	na	na	na	na	na	na	na	na
IHSMarkit	na	na	na	na	na	na	0.76	0.75	0.73
ING Financial Markets	1.90	1.90	2.15	2.80	2.90	3.10	0.80	0.84	0.88
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Moody's Analytics	na	na	na	2.65	2.81	3.15	0.78	0.77	0.77
Moody's Capital Markets	na	na	na	2.55	2.60	2.50	0.76	0.75	0.75
Nomura Securities	na	na	na	na	na	na	0.80	0.82	0.84
Oxford Economics	na	na	na	2.95	3.01	3.08	0.76	0.75	0.74
Scotiabank	na	na	na	na	na	na	0.79	0.79	0.80
Wells Fargo	na	na	na	na	na	na	na	na	na
December Consensus	**1.90**	**1.90**	**2.15**	**2.74**	**2.83**	**2.96**	**0.78**	**0.78**	**0.79**
High	1.90	1.90	2.15	2.95	3.01	3.15	0.80	0.84	0.88
Low	1.90	1.90	2.15	2.55	2.60	2.50	0.76	0.75	0.73
Last Months Avg.	1.65	1.65	1.90	2.78	2.83	2.99	0.79	0.80	0.80

Eurozone

	3 Mo. Interest Rate %			USD/EUR		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	1.17	1.19	na
BMO Capital Markets	-0.40	-0.40	-0.40	1.16	1.15	1.19
IHSMarkit	na	na	na	1.15	1.15	1.16
ING Financial Markets	-0.33	-0.33	-0.33	1.20	1.22	1.27
Mizuho Research Institute	-0.30	-0.30	-0.30	1.16	1.16	1.19
Moody's Analytics	na	na	na	1.16	1.15	1.14
Moody's Capital Markets	na	na	na	1.17	1.16	1.16
Nomura Securities	na	na	na	1.25	1.28	1.35
Oxford Economics	na	na	na	1.20	1.20	1.20
Scotiabank	na	na	na	1.18	1.18	1.20
Wells Fargo	-0.35	-0.25	0.05	na	na	na
December Consensus	**-0.35**	**-0.32**	**-0.25**	**1.18**	**1.18**	**1.21**
High	-0.30	-0.25	0.05	1.25	1.28	1.35
Low	-0.40	-0.40	-0.40	1.15	1.15	1.14
Last Months Avg.	-0.35	-0.33	-0.27	1.19	1.20	1.22

	10 Yr. Gov't Bond Yields %											
	Germany			France			Italy			Spain		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.55	0.60	na	na	na	na	na	na	na	na	na	na
BMO Capital Markets	0.65	0.80	1.05	na	na	na	na	na	na	na	na	na
ING Financial Markets	0.50	0.65	0.75	0.92	0.97	1.15	2.35	2.25	2.35	1.85	1.85	1.95
Mizuho Research Institute	0.40	0.45	0.50	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.66	0.79	1.12	0.99	1.10	1.34	1.96	2.00	2.25	1.80	1.93	2.23
Moody's Capital Markets	0.45	0.49	0.52	0.75	0.84	0.92	1.85	1.92	1.97	1.60	1.65	1.65
Nomura Securities	na	na	na	na	na	na	na	na	na	na	na	na
Oxford Economics	0.65	0.75	0.90	1.05	1.17	1.36	2.20	2.33	2.54	1.85	2.00	2.21
Wells Fargo	0.60	0.75	1.00	na	na	na	na	na	na	na	na	na
December Consensus	**0.56**	**0.66**	**0.83**	**0.93**	**1.02**	**1.19**	**2.09**	**2.13**	**2.28**	**1.78**	**1.86**	**2.01**
High	0.66	0.80	1.12	1.05	1.17	1.36	2.35	2.33	2.54	1.85	2.00	2.23
Low	0.40	0.45	0.50	0.75	0.84	0.92	1.85	1.92	1.97	1.60	1.65	1.65
Last Months Avg.	0.56	0.63	0.86	0.92	1.03	1.25	2.19	2.48	2.57	1.78	1.94	2.16

	Consensus Forecasts 10-year Bond Yields vs U.S. Yield			
	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-2.33	-2.48	-2.57	-2.73
United Kingdom	-1.03	-1.06	-1.07	-1.09
Switzerland	-2.45	-2.54	-2.54	-2.56
Canada	-0.46	-0.30	-0.27	-0.18
Australia	0.17	0.20	0.19	0.14
Germany	-2.01	-1.98	-1.98	-1.98
France	-1.70	-1.61	-1.62	-1.62
Italy	-0.59	-0.45	-0.51	-0.54
Spain	-0.88	-0.77	-0.78	-0.81

	Consensus Forecasts 3 Mo. Deposit Rates vs U.S. Rate			
	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-1.49	-1.64	-1.93	-2.12
United Kingdom	-1.01	-1.06	-1.29	-1.33
Switzerland	-2.20	-2.36	-2.61	-2.74
Canada	-0.10	0.11	-0.04	-0.34
Australia	0.53	0.24	-0.01	0.01
Eurozone	-1.78	-2.01	-2.23	-2.38

Viewpoints:

A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

Inflation: Mystery And Brewing Risk

One theme that has emerged over the past few years has been the complete lack of traction in inflation among developed economies. Fed Chair Yellen has called it a mystery, while the Bank of Canada has said they are studying the issue closely. Whatever you want to call it, there's no debating that inflation pressures remain exceptionally subdued more than six years into the expansion (or over eight years since the recession trough). Indeed, U.S. CPI has risen just 1.25% annualized over the past five years, matching lows seen during a brief period in 2013 and a four-year span in the mid-1960s, with only the late-1950s sporting a meaningfully slower pace. The Canadian backdrop is similar with the five-year annualized rate also hovering near multi-decade lows. Market-based inflation expectations have fallen as well, adjusting to the persistent lack of inflation pressure. While we won't dispute the data, the complacency that's building around low and subdued inflation is a brewing risk for markets.

When breaking down inflation, it's important to differentiate between cyclical and secular drivers. The secular drivers have been hogging the headlines recently, with fears of job-stealing robots, artificial intelligence, technology-driven efficiencies, a lengthy recession hangover for workers, and worsening demographics just a few on a lengthy list of factors blamed for keeping inflation in check. Another potential factor is that the cost of producing goods continues to be very restrained. Through the early 2000s, it was reasonable to pin this trend on the opening of global trade and China joining the WTO in particular. While this factor is still at play, we'd point to increasing automation of goods production which keeps the marginal cost of incremental goods production relatively steady, in turn, limiting any inflation pressure. Indeed, goods (ex. food & energy) inflation has been nearly zero over the past 20 years. This phenomenon shows no sign of reversing any time soon. All of the above factors are likely to restrain inflation consistently for the foreseeable future, but that doesn't mean price pressures are gone forever.

The cyclical aspect of inflation is equally, if not more, important than the secular. The 2008/09 Great Recession was the worst global downturn since the Great Depression. That was true for the U.S. and it was second to the early 1980s for Canada, creating a very wide output gap in both countries. It's taken more than six years of expansion, but the output gaps in the U.S. and Canada are arguably closed, or at least nearly so. Traditionally, inflation dynamics are driven by supply and demand. Assuming the basic laws of economics still hold, it's reasonable to expect inflation pressures will build through 2018. We've seen little to support that view yet, but there are two potential reasons for the delay: 1) the output gaps have only just closed, so inflation pressures haven't had time to build; 2) slack remains in the labour market.

This latter point has occupied policymakers at the Fed and BoC. The drop in employment in 2008/09 was even more severe than the decline in GDP. Not only did jobless rates rise, but participation rates moved lower as many dropped out of the labour force. The latter was especially the case in the U.S. As the North American labour markets have made progress, the jobless rate has fallen at or close to prerecession lows. However, underemployment has yet to fully retrace all of its increase in Canada, suggesting that some slack in the labour market remains. The U.S. measure has only just reached pre-recession levels. Indeed, that would help explain why wage growth has been quite subdued despite consistently solid job growth. The Fed and BoC appear to have similar beliefs, but there are clearly lingering doubts (see this week's FOMC minutes). Assuming job growth holds up through 2018, wages look to accelerate as the limited amount of labour market slack is taken up. What's clear is that this is an area of potentially meaningful upside for inflation over the coming year.

From a global perspective, the cyclical indicators are solid as well. The global economy looks like it will have its strongest performance in at least three years. Perhaps the best indicator of this improving macro backdrop is the rising trend in commodity prices and industrial metals in particular. While oil prices have historically been a good indicator of global growth, oil has not been as responsive to better growth due to the supply dynamic driven by U.S. shale, though prices have moved up in recent weeks. The better growth backdrop in 2017 is expected to persist into 2018 (we see no meaningful imbalances to derail growth at present, absent a black swan) which will be supportive of commodity prices. That in turn will help lift inflation.

Key Takeaway: Inflation has persistently surprised on the low side of forecasts in recent years, which is keeping market inflation expectations subdued. However, cyclical drivers suggest that risks are tilted to the upside for 2018, potentially shaking market participants out of their low-inflation complacency.

Benjamin Reitzes, BMO Capital Market, Toronto, Canada

The Yield Curve: Signal Or Noise?

A string of generally favorable economic statistics has pushed interest rates higher since September, with the sharpest move occurring in the short end of the maturity spectrum. The rate on two-year Treasury securities has increased approximately 40 basis points in the past three months and moved to its highest level since the recession; the 10-year rate has increased only 20 basis points over this span and has remained comfortably within its recent range. This combination of changes has led to a noticeable narrowing in the slope of the yield curve.

The slope of the yield curve is viewed by many as a reliable indicator of cyclical shifts in the economy: it usually steepens during recessions and the early portions of expansions before narrowing during the middle and latter portions of expansions and typically inverting before the onset of recession. The narrowing that has emerged recently might lead some to think that the eight-year expansion is beginning to show its age; in the extreme, the narrowing might stir thoughts of recession on the horizon.

We would dismiss thoughts of recession. Although the curve has flattened, it is far from the negative (inverted) readings that usually precede a downturn. Moreover, we do not view the narrowing of the curve as a sign that the expansion is entering an advanced stage that might bring a loss of momentum. The narrowing of the curve and slower economic growth that has occurred in past cycles were largely the result of the Federal Reserve aggressively tightening monetary policy. Thoughts of additional rate hikes have certainly been a factor behind the recent increase in short-term interest rates, but policy remains accommodative, and the Fed plans to move gradually in normalizing policy. If officials were to err in calibrating policy, we suspect that they would tighten too little rather than too much; they would probably tolerate inflation breaching target (slightly), and they are not likely to risk derailing the expansion.

Even if the curve were to continue narrowing and possibly invert, we would not necessarily conclude that a slowdown or recession is imminent. Although the slope of the yield curve *(continued on next page)*

Viewpoints

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has been a reliable guide to cyclical shifts in the past, historical guidelines might not be relevant in the current instance. Because of the quantitative easing programs of the Federal Reserve, the long end of the maturity spectrum -- and hence the slope of the yield curve -- is likely to behave differently than in the past. The Fed is now trimming its portfolio, which will lessen the distortions associated with QE, but officials are still in the early phases of this effort, and thus long-term interest rates are not market driven. That is, distortions in the long end remain in place and therefore the yield curve is likely to move differently than it has in the past.

In addition, the foreign sector is playing a larger role in U.S. financial markets than it did in the past. Economies and financial markets are now highly integrated, and therefore developments abroad are likely to have feedback effects on the United States. In particular, The European Central Bank and the Bank of Japan have active quantitative-easing programs in place that are constraining long-term interest rates in their markets. In response, investors with a global focus would shift portfolios toward the U.S., which would limit upward pressure on long-term interest rates that might have occurred in the past, disrupting the normal response of the yield curve to cyclical changes in the U.S. economy.

In short, the unconventional policies of central banks have altered the financial landscape, and therefore, past metrics and guidelines might not apply.

Michael Moran, Daiwa Capital Markets, New York

Is The Bond Market Telling The Fed To "Go" Or "Slow"?

The yield curve can be a good warning indicator for trouble ahead. When a central bank tightens and pushes short rates above long rates, this "inversion" signals that the bond market expects a weaker economy and rate cuts in the future. Conversely the yield curve is steep when monetary policy is accommodative and so economic activity is likely to accelerate in the future. For this reason, the slope of the yield curve has historically been viewed as a reliable recession predictor.

There is a vast amount of academic literature on this issue. However, studies have found that the yield curve has become less predictive of economic activity in recent decades, both in the US and in other developed economies. For example, the New York Fed's recession probability model, which is based on the 3-month/10-year US Treasury yield spread, has not predicted more than a 50% chance of a recession since the early 1980s.

While the disconnect between the yield curve and economic growth started in the 1990s, it was exacerbated by the bond conundrum of the mid-2000s. Despite the steady Fed tightening from 2004 to 2006, long-end Treasury yields refused to budge. These persistently low yields could be interpreted in one of two ways. On the one hand, they may have been a signal of weak growth ahead, suggesting further Fed hikes would be a mistake. On the other hand, they could have been interpreted as a sign of very accommodative financial conditions, suggesting the Fed should forge ahead. In the event, the Fed made the right call, blaming low yields on foreign capital inflows, taking note of the ongoing easing of credit conditions and forging ahead with rate hikes. Although the economy eventually fell into a deep recession, it was caused more by surging oil prices and a collapse in credit markets than the earlier Fed rate hikes.

More recently, with central banks manipulating both the short and long ends of the curve, its slope has become an even less reliable gauge of recession risk. Aggressive QE has helped drive term premiums to around zero. If near-zero term premiums persist then the yield curve should be inverted about half of the time. After all, if there is no term premium, then on average short and long rates should be equal.

At the extreme, the BOJ's yield curve control has made the Japanese curve almost meaningless as a measure of market views of the economy. The BOJ is keeping the curve upward sloping as a favor to financial firms; however, this tells us nothing about the prospects for Japanese growth and inflation. Taken literally, the Japanese curve suggests that the prospects for growth in Japan have been falling for 8 consecutive years. There was also a strong false signal of recession last year. In reality, however, Japanese growth is accelerating, not slowing.

In the Euro area the message from the curve has become very complicated. The recent steepening of the German curve is likely driven by both good news (an improving economy) and bad news (the winding down of QE). Meanwhile the yield curves in the periphery are even more complicated: credit risk premiums, QE, and growth and inflation expectations are all likely influencing yields. Is a steeper Italian yield curve a good or a bad sign? It depends on which story is dominating.

Adding to the complexity in interpreting local yield curves are cross-border effects. Surely, super-low yields in some countries are impacting yields in other countries, contaminating the signal about the domestic outlook.

Today the Fed faces the same dilemma as in the 2000s-are persistently low bond yields good news or bad news? In our view, the Fed is making the same choice today as back then: easy financial conditions argue for full-speed ahead. After all, low bond yields are not the only sign of easy financial conditions-equity and home prices are surging and growth momentum is strong in the US and globally. These easy financial conditions encourage the Fed to move ahead with its exit plans.

Easing financial conditions and stronger growth in the face of Fed hikes are signs that "r-star" -- the neutral or equilibrium real policy rate -- is probably starting to rebound. For a number of years, economists both at the Fed and elsewhere have been lowering their estimates of both the short-run and the long-run values of r-star. For example, when the FOMC first published its participants' estimates of long-run r-star in 2012, the median estimate was 2.25%; today the median forecast is 0.75%. Moreover, much of the Fed discussion seems to assume that the short-run r-star is currently roughly zero.

It will take time for model estimates of r-star to catch up to the new rising trend. Models such as that of Laubach and Williams use very simple structures and are heavily smoothed. However, the evidence for a higher r-star is building as a year of steady Fed exit has had no noticeable impact on financial conditions or growth. If r-star were really zero there should be some pain evident by now.

We have two messages for investors. First, the Fed is likely to stay the course. Second, we would not worry about the flat yield curve.

Ethan Harris and Aditya Bhave, Bank of America-Merrill Lynch, New York, NY

Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2019 through 2023 and averages for the five-year periods 2019-2023 and 2024-2028. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		----------Average For The Year----------					Five-Year Averages	
Interest Rates		**2019**	**2020**	**2021**	**2022**	**2023**	**2019-2023**	**2024-2028**
1. Federal Funds Rate	**CONSENSUS**	**2.5**	**2.7**	**2.9**	**2.9**	**2.9**	**2.8**	**3.0**
	Top 10 Average	2.9	3.2	3.4	3.4	3.5	3.3	3.5
	Bottom 10 Average	2.1	2.0	2.3	2.3	2.4	2.2	2.4
2. Prime Rate	**CONSENSUS**	**5.5**	**5.8**	**5.9**	**5.9**	**5.9**	**5.8**	**5.9**
	Top 10 Average	5.9	6.3	6.4	6.5	6.6	6.3	6.5
	Bottom 10 Average	5.0	5.1	5.2	5.2	5.2	5.1	5.3
3. LIBOR, 3-Mo.	**CONSENSUS**	**2.8**	**3.1**	**3.2**	**3.1**	**3.2**	**3.1**	**3.2**
	Top 10 Average	3.2	3.6	3.8	3.8	3.9	3.7	3.8
	Bottom 10 Average	2.4	2.6	2.6	2.5	2.6	2.5	2.6
4. Commercial Paper, 1-Mo.	**CONSENSUS**	**2.6**	**2.9**	**3.0**	**3.0**	**3.1**	**2.9**	**3.1**
	Top 10 Average	3.1	3.5	3.6	3.7	3.8	3.5	3.8
	Bottom 10 Average	2.2	2.5	2.6	2.5	2.5	2.5	2.6
5. Treasury Bill Yield, 3-Mo.	**CONSENSUS**	**2.5**	**2.8**	**2.9**	**2.9**	**2.9**	**2.8**	**2.9**
	Top 10 Average	2.9	3.3	3.4	3.4	3.5	3.3	3.5
	Bottom 10 Average	2.1	2.3	2.4	2.3	2.3	2.3	2.4
6. Treasury Bill Yield, 6-Mo.	**CONSENSUS**	**2.6**	**2.9**	**3.0**	**3.0**	**3.0**	**2.9**	**3.1**
	Top 10 Average	3.0	3.4	3.5	3.6	3.7	3.5	3.7
	Bottom 10 Average	2.2	2.4	2.5	2.4	2.4	2.4	2.5
7. Treasury Bill Yield, 1-Yr.	**CONSENSUS**	**2.7**	**3.0**	**3.1**	**3.1**	**3.2**	**3.0**	**3.2**
	Top 10 Average	3.2	3.6	3.7	3.7	3.8	3.6	3.9
	Bottom 10 Average	2.3	2.5	2.6	2.5	2.5	2.5	2.6
8. Treasury Note Yield, 2-Yr.	**CONSENSUS**	**2.8**	**3.1**	**3.3**	**3.2**	**3.3**	**3.1**	**3.3**
	Top 10 Average	3.3	3.8	3.8	3.8	3.9	3.7	4.0
	Bottom 10 Average	2.4	2.6	2.7	2.6	2.6	2.6	2.7
10. Treasury Note Yield, 5-Yr.	**CONSENSUS**	**3.1**	**3.4**	**3.5**	**3.5**	**3.5**	**3.4**	**3.6**
	Top 10 Average	3.6	3.9	4.1	4.1	4.1	3.9	4.3
	Bottom 10 Average	2.6	2.8	2.9	2.9	2.9	2.8	3.0
11. Treasury Note Yield, 10-Yr.	**CONSENSUS**	**3.3**	**3.6**	**3.7**	**3.7**	**3.8**	**3.6**	**3.8**
	Top 10 Average	3.9	4.2	4.3	4.3	4.3	4.2	4.5
	Bottom 10 Average	2.8	2.9	3.1	3.1	3.1	3.0	3.2
12. Treasury Bond Yield, 30-Yr.	**CONSENSUS**	**3.8**	**4.1**	**4.2**	**4.2**	**4.2**	**4.1**	**4.3**
	Top 10 Average	4.4	4.7	4.7	4.7	4.8	4.7	5.0
	Bottom 10 Average	3.3	3.5	3.6	3.5	3.6	3.5	3.7
13. Corporate Aaa Bond Yield	**CONSENSUS**	**4.9**	**5.1**	**5.2**	**5.2**	**5.3**	**5.1**	**5.4**
	Top 10 Average	5.5	5.9	5.9	6.0	6.0	5.9	6.2
	Bottom 10 Average	4.3	4.5	4.5	4.5	4.6	4.5	4.7
13. Corporate Baa Bond Yield	**CONSENSUS**	**5.7**	**6.0**	**6.0**	**6.0**	**6.1**	**6.0**	**6.2**
	Top 10 Average	6.4	6.8	6.8	6.9	6.9	6.8	7.0
	Bottom 10 Average	5.0	5.2	5.3	5.2	5.3	5.2	5.4
14. State & Local Bonds Yield	**CONSENSUS**	**4.4**	**4.5**	**4.6**	**4.5**	**4.6**	**4.5**	**4.8**
	Top 10 Average	5.0	5.2	5.2	5.3	5.3	5.2	5.5
	Bottom 10 Average	3.9	4.0	4.0	3.9	4.1	4.0	4.1
15. Home Mortgage Rate	**CONSENSUS**	**5.0**	**5.2**	**5.3**	**5.3**	**5.4**	**5.2**	**5.5**
	Top 10 Average	5.5	5.8	5.9	6.0	6.0	5.8	6.1
	Bottom 10 Average	4.5	4.7	4.7	4.6	4.7	4.6	4.9
A. FRB - Major Currency Index	**CONSENSUS**	**90.4**	**90.0**	**89.9**	**89.9**	**90.0**	**90.0**	**90.4**
	Top 10 Average	94.7	94.8	95.0	95.1	95.3	95.0	95.4
	Bottom 10 Average	86.9	85.8	85.4	85.5	85.6	85.8	86.1
		----------Year-Over-Year, % Change----------					Five-Year Averages	
		2019	**2020**	**2021**	**2022**	**2023**	**2019-2023**	**2024-2028**
B. Real GDP	**CONSENSUS**	**2.2**	**1.9**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**
	Top 10 Average	2.5	2.4	2.5	2.4	2.3	2.4	2.4
	Bottom 10 Average	1.8	1.4	1.7	1.6	1.7	1.6	1.7
C. GDP Chained Price Index	**CONSENSUS**	**2.2**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.5	2.3	2.3	2.3	2.3	2.3	2.3
	Bottom 10 Average	1.8	1.9	1.9	2.0	1.9	1.9	1.9
D. Consumer Price Index	**CONSENSUS**	**2.3**	**2.3**	**2.3**	**2.2**	**2.2**	**2.3**	**2.2**
	Top 10 Average	2.7	2.6	2.6	2.4	2.4	2.5	2.4
	Bottom 10 Average	1.9	1.9	2.0	2.0	2.0	2.0	2.0

Databank:

2017 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	0.5	-0.2	0.1	0.3	0.0	-0.1	0.5	-0.1	1.9	0.2		
Auto & Light Truck Sales (b)	17.33	17.33	16.72	16.97	16.70	16.61	16.69	16.02	18.47	18.00		
Personal Income (a, current $)	0.4	0.5	0.3	0.1	0.3	0.0	0.3	0.2	0.4			
Personal Consumption (a, current $)	0.2	0.1	0.5	0.3	0.2	0.1	0.4	0.1	1.0			
Consumer Credit (e)	3.1	5.2	4.7	3.9	5.8	3.7	5.7	4.2	6.6			
Consumer Sentiment (U. of Mich.)	98.5	96.3	96.9	97.0	97.1	95.1	93.4	96.8	95.1	100.7	98.5	
Household Employment (c)	-30	447	472	156	-233	245	345	-74	906	-484		
Non-farm Payroll Employment (c)	216	232	50	207	145	210	189	208	18	261		
Unemployment Rate (%)	4.8	4.7	4.5	4.4	4.3	4.4	4.3	4.4	4.2	4.1		
Average Hourly Earnings (All, cur. $)	26.02	26.10	26.13	26.18	26.22	26.27	26.39	26.42	26.54	26.53		
Average Workweek (All, hrs.)	34.4	34.3	34.3	34.5	34.4	34.5	34.5	34.4	34.4	34.4		
Industrial Production (d)	0.0	0.4	1.4	2.0	2.2	2.0	1.9	1.6	2.1	2.8		
Capacity Utilization (%)	75.7	75.8	75.9	76.6	76.6	76.6	76.5	76.1	76.4	77.0		
ISM Manufacturing Index (g)	56.0	57.7	57.2	54.8	54.9	57.8	56.3	58.8	60.8	58.7		
ISM Non-Manufacturing Index (g)	56.5	57.6	55.2	57.5	56.9	57.4	53.9	55.3	59.8	60.1		
Housing Starts (b)	1.236	1.288	1.189	1.154	1.129	1.217	1.185	1.172	1.135	1.290		
Housing Permits (b)	1.300	1.219	1.260	1.228	1.168	1.275	1.230	1.272	1.225	1.297		
New Home Sales (1-family, c)	599	615	638	590	606	614	582	561	667			
Construction Expenditures (a)	0.8	1.9	0.3	-1.8	1.6	-0.8	-0.9	0.1	0.3			
Consumer Price Index (nsa., d)	2.5	2.7	2.4	2.2	1.9	1.6	1.7	1.9	2.2	2.0		
CPI ex. Food and Energy (nsa., d)	2.3	2.2	2.0	1.9	1.7	1.7	1.7	1.7	1.7	1.8		
Producer Price Index (n.s.a., d)	1.7	2.0	2.2	2.5	2.3	1.9	1.9	2.4	2.6	2.8		
Durable Goods Orders (a)	2.4	1.4	2.4	-0.8	0.0	6.4	-6.8	2.1	2.2	-1.2		
Leading Economic Indicators (g)	0.6	0.5	0.4	0.2	0.3	0.6	0.3	0.4	0.1	1.2		
Balance of Trade & Services (f)	-48.8	-44.5	-44.8	-47.4	-46.4	-43.5	-43.6	-42.8	-43.5			
Federal Funds Rate (%)	0.65	0.66	0.76	0.90	0.90	1.03	1.15	1.15	1.16	1.15		
3-Mo. Treasury Bill Rate (%)	0.51	0.53	0.73	0.80	0.90	1.02	1.09	1.04	1.06	1.09		
10-Year Treasury Note Yield (%)	2.43	2.43	2.47	2.30	2.31	2.19	2.32	2.33	2.28	2.36		

2016 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	-1.0	0.7	0.0	0.8	0.3	0.8	0.0	-0.1	1.0	0.6	0.1	0.9
Auto & Light Truck Sales (b)	17.64	17.51	16.77	17.49	17.22	16.99	17.75	17.13	17.65	17.80	17.56	18.05
Personal Income (a, current $)	0.0	-0.1	0.3	0.5	0.3	0.3	0.4	0.2	0.4	0.4	0.2	0.3
Personal Consumption (a, current $)	0.1	0.2	0.0	1.1	0.3	0.5	0.4	0.1	0.7	0.5	0.3	0.6
Consumer Credit (e)	4.4	4.4	9.9	5.7	7.5	4.8	5.8	9.0	6.9	5.2	8.3	4.5
Consumer Sentiment (U. of Mich.)	92.0	91.7	91.0	89.0	94.7	93.5	90.0	89.8	91.2	87.2	93.8	98.2
Household Employment (c)	503	510	258	-273	30	32	456	109	271	-24	146	63
Non-Farm Payroll Employment (c)	126	237	225	153	43	297	291	176	249	124	164	155
Unemployment Rate (%)	4.9	4.9	5.0	5.0	4.7	4.9	4.9	4.9	4.9	4.8	4.6	4.7
Average Hourly Earnings (All, cur. $)	25.37	25.38	25.46	25.54	25.59	25.62	25.71	25.74	25.81	25.90	25.91	25.97
Average Workweek (All, hrs.)	34.6	34.5	34.4	34.4	34.4	34.4	34.4	34.3	34.4	34.4	34.3	34.4
Industrial Production (d)	-2.0	-2.0	-.25	-1.7	-1.4	-0.9	-1.2	-1.3	-1.2	-0.8	-0.5	0.9
Capacity Utilization (%)	76.1	75.9	75.4	75.6	75.6	75.8	75.9	75.8	75.6	75.7	75.5	76.0
ISM Manufacturing Index (g)	48.2	49.7	51.7	50.7	51.0	52.8	52.3	49.4	51.7	52.0	53.5	54.5
ISM Non-Manufacturing Index (g)	53.5	54.3	54.9	55.7	53.6	56.1	54.9	51.7	56.6	54.6	56.2	56.6
Housing Starts (b)	1.123	1.209	1.128	1.164	1.119	1.190	1.223	1.164	1.062	1.328	1.149	1.268
Housing Permits (b)	1.193	1.195	1.115	1.163	1.178	1.193	1.175	1.200	1.270	1.285	1.255	1.266
New Home Sales (1-family, c)	520	525	533	566	560	559	627	567	570	577	579	548
Construction Expenditures (a)	-0.3	1.4	1.6	-2.9	0.1	0.9	0.5	0.5	-0.2	0.8	1.5	-0.2
Consumer Price Index (s.a., d)	1.4	1.0	0.9	1.1	1.0	1.0	0.8	1.1	1.5	1.6	1.7	2.1
CPI ex. Food and Energy (s.a., d)	2.2	2.3	2.2	2.1	2.2	2.2	2.2	2.3	2.2	2.1	2.1	2.2
Producer Price Index (n.s.a., d)	0.0	0.1	-0.1	0.2	0.0	0.2	0.0	0.0	0.6	1.1	1.3	1.7
Durable Goods Orders (a)	4.3	-3.3	2.0	3.2	-2.9	-4.3	3.6	0.2	0.3	5.0	-4.7	-0.9
Leading Economic Indicators (g)	-0.2	0.1	0.1	0.5	-0.2	0.2	0.5	-0.2	0.3	0.2	0.2	0.6
Balance of Trade & Services (f)	-43.4	-45.3	-37.4	-38.4	-41.5	-43.8	-41.3	-41.1	-38.5	-43.1	-46.4	-44.6
Federal Funds Rate (%)	0.34	0.38	0.36	0.37	0.37	0.38	0.39	0.40	0.40	0.40	0.41	0.54
3-Mo. Treasury Bill Rate (%)	0.26	0.31	0.29	0.23	0.27	0.27	0.30	0.30	0.29	0.33	0.45	0.51
10-Year Treasury Note Yield (%)	2.09	1.78	1.89	1.81	1.81	1.64	1.50	1.56	1.63	1.76	2.14	2.49

(a) month-over-month % change; (b) millions, saar; (c) month-over-month change, thousands; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level. Most series are subject to frequent government revisions. Use with care.

Calendar Of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
27 Markit Services PMI (Nov, Flash) New Home Sales (Oct) Dallas Fed Manufacturing survey (Nov)	**28** Advance Economic Indicators (Oct) S&P/Case-Shiller Home Price Index (Sep) FHFA Home Price Survey (Sep, Consumer Confidence (Nov, Conference Board) Dallas Fed Services (Nov) Richmond Fed Services (Nov)	**29** Real GDP (Q3, Second) Pending Home Sales (Oct) Beige Book EIA Crude Oil Stocks Mortgage Applications	**30** Personal Income and Consumption (Oct) Chicago PMI (Nov) Weekly Jobless Claims Weekly Money Supply	**December 1** Markit Manufacturing PMI (Nov, Final) ISM Manufacturing (Nov) Construction spending (Oct) Light Vehicle Sales (Nov)
4 Factory Orders (Oct)	**5** International Trade (Oct) Markit Services PMI (Nov, Final) ISM Non-Manufacturing (Nov) QFR (Q3)	**6** ADP Employment (Nov) Productivity and Costs (Q3) EIA Crude Oil Stocks Mortgage Applications	**7** Quarterly Spending Survey (Q3) Consumer Spending (Oct) Weekly Jobless Claims Weekly Money Supply	**8** Employment (Nov) Consumer Sentiment (Dec, Preliminary) Wholesale Trade (Oct)
11 JOLTS (Oct)	**12** **FOMC Meeting** NFIB survey (Nov) Producer Price Index (Nov) Federal Budget (Nov)	**13** **FOMC Meeting** **Statement and projections (2:00 pm)** **Press conference (2:30)** Consumer Price Index (Nov) EIA Crude Oil Stocks Mortgage Applications	**14** Retail Sales (Nov) IHSMarkit Manufacturing PMI (Dec, flash) Import Prices (Nov) Business Inventories (Oct) Weekly Jobless Claims Weekly Money Supply	**15** Industrial Production (Nov) Empire State Manufacturing (Dec) TIC data (Oct
18 IHSMarkit Services PMI (Dec, flash) NAHB survey (Dec) Business Leaders Survey (Dec)	**19** Housing Starts (Nov) Current Account (Q3)	**20** Existing Home Sales (Nov) EIA Crude Oil Stocks Mortgage Applications	**21** Real GDP (Q3, Third estimate) Philadelphia Fed Manufacturing survey (Dec) FHFA home price survey (Oct) Weekly Jobless Claims Weekly Money Supply	**22** Personal Income and Consumption (Nov) Durable Goods (Nov) New Home Sales (Nov) Philadelphia Fed manufacturing survey (Dec) Consumer Sentiment (Dec, final, University of Michigan) Kansas City Fed Survey (Nov)
25 **Christmas Day** **Markets Closed**	**26** S&P/Case-Shiller Home Price Index (Oct) Consumer Confidence (Dec, Conference Board) Dallas Fed Manufacturing (Dec) Richmond Fed Surveys (Dec)	**27** Pending Home Sales (Nov) Dallas Fed Services (Dec) EIA Crude Oil Stocks	**28** Chicago PMI (Dec) Advance Economic Indicators (Nov) Weekly Jobless Claims Weekly Money Supply	**29**
January 1 **New Year's Day** **Markets Closed**	**2** IHSMarkit Manufacturing PMI (Dec, Final)	**3** ISM Manufacturing (Dec) Construction Spending (Nov) Light Vehicle Sales (Dec) EIA Crude Oil Stocks **FOMC Minutes**	**4** ADP Employment (Dec) IHSMarkit Services PMI (Dec,Final) Weekly Jobless Claims Weekly Money Supply	**5** Employment (Dec) International Trade (Nov) ISM Non-Manufacturing (Dec) Factory Orders (Nov)

BLUE CHIP FORECASTERS

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Source: Bloomberg Professional

Ticker	ALE	LNT	BKH	EE	HE	NWE	IDA	OGE	PNM	30-Yr. Treas.
30 Day Avera	$75.14	$41.78	$55.99	$52.19	$34.29	$54.13	$90.21	$33.02	$38.67	$3.12
90 Day Avera	$71.97	$40.18	$54.09	$50.88	$33.90	$53.03	$86.23	$32.04	$37.18	
180 Day Aver	$74.74	$41.68	$58.76	$53.98	$34.72	$56.40	$89.19	$33.67	$39.81	

PX_LAST	ALE US Equity	LNT US Equity	BKH US Equity	EE US Equity	HE US Equity	NWE US Equity	IDA US Equity	OGE US Equity	PNM US Equity	H15T30 Index
5/18/2018	74.49	40.57	56.18	55.40	32.98	53.21	87.90	33.35	37.90	3.2
5/17/2018	74.00	40.64	56.20	54.40	33.14	53.26	88.04	33.31	37.80	3.25
5/16/2018	74.38	40.89	56.76	55.40	33.25	53.15	88.74	33.61	37.95	3.21
5/15/2018	75.00	41.05	57.22	56.10	33.53	53.48	89.27	33.64	38.15	3.2
5/14/2018	76.00	41.41	57.95	56.25	33.74	53.49	90.48	33.99	38.50	3.13
5/11/2018	77.78	41.66	58.21	56.55	33.84	53.72	91.24	34.23	38.70	3.1
5/10/2018	77.33	41.74	58.12	56.40	34.16	53.72	91.44	34.24	38.45	3.12
5/9/2018	76.57	41.26	57.58	55.90	33.87	53.22	91.27	33.60	38.20	3.16
5/8/2018	76.96	41.72	58.31	55.10	34.22	53.66	91.07	33.82	38.40	3.13
5/7/2018	78.86	42.94	59.15	55.65	34.88	55.34	93.06	34.33	39.40	3.12
5/4/2018	79.62	43.27	58.95	55.05	35.07	55.53	94.04	34.17	40.10	3.12
5/3/2018	78.79	43.23	57.67	54.25	34.75	55.38	95.42	33.74	39.75	3.12
5/2/2018	77.37	42.87	57.48	50.85	34.65	54.79	93.12	33.10	38.95	3.14
5/1/2018	76.30	42.82	56.80	51.00	34.71	55.19	92.90	32.83	39.15	3.13
4/30/2018	76.41	42.95	56.68	51.05	34.69	54.94	93.00	32.87	39.65	3.11
4/27/2018	77.08	43.06	56.86	51.35	34.89	55.36	93.63	32.91	40.05	3.13
4/26/2018	76.37	42.86	56.34	50.80	34.55	54.78	93.12	32.91	39.70	3.18
4/25/2018	75.27	42.23	55.74	49.95	34.41	54.79	91.82	32.80	39.15	3.21
4/24/2018	74.90	42.10	55.45	49.95	34.51	54.30	91.99	32.80	39.50	3.18
4/23/2018	73.67	41.69	54.36	49.35	34.52	54.04	90.51	32.51	38.95	3.15
4/20/2018	73.10	41.54	54.24	49.05	34.30	53.85	89.08	32.47	38.65	3.14
4/19/2018	73.71	41.53	54.51	49.50	34.30	53.90	89.36	32.76	38.75	3.11
4/18/2018	73.61	41.60	54.33	49.75	34.47	54.17	88.80	32.75	38.60	3.06
4/17/2018	74.21	41.85	54.41	50.25	34.92	54.59	88.84	32.62	39.10	3
4/16/2018	73.14	41.59	53.79	49.85	34.62	54.66	87.70	32.30	38.70	3.03
4/13/2018	71.67	41.11	53.13	48.90	34.18	53.27	85.74	31.61	37.80	3.03
4/12/2018	71.49	40.52	52.69	48.55	33.92	52.93	84.98	31.56	37.25	3.05
4/11/2018	72.11	41.02	53.44	49.55	34.43	53.45	86.31	31.80	37.50	2.99
4/10/2018	72.04	40.75	53.48	49.60	34.45	53.78	86.29	31.80	37.50	3.02
4/9/2018	71.86	41.05	53.64	50.05	34.74	53.82	87.10	32.07	37.85	3.02
4/6/2018	71.72	41.02	53.99	50.35	34.76	53.89	87.25	32.37	37.95	3.01
4/5/2018	71.71	41.33	54.71	50.60	34.90	54.22	87.66	32.85	38.10	3.07
4/4/2018	71.43	40.92	54.21	50.20	34.32	53.53	86.94	32.27	37.90	3.03
4/3/2018	71.32	40.82	54.45	50.20	34.59	53.40	86.94	32.54	37.85	3.02
4/2/2018	70.90	40.79	53.96	50.00	34.11	52.83	86.22	32.12	37.55	2.97
3/29/2018	72.25	40.86	54.30	51.00	34.38	53.80	88.27	32.77	38.25	2.97
3/28/2018	71.83	40.62	53.96	50.60	34.35	53.16	87.61	32.33	38.30	3.01
3/27/2018	71.72	40.53	53.55	50.15	34.22	52.91	87.01	32.26	37.90	3.03
3/26/2018	70.94	39.84	52.89	49.75	33.81	52.35	85.68	31.81	37.35	3.08
3/23/2018	70.12	39.45	52.00	48.85	33.32	51.52	84.34	31.43	36.45	3.06
3/22/2018	71.01	39.83	53.03	49.75	33.76	52.20	85.88	31.81	37.20	3.06
3/21/2018	71.26	39.66	53.22	49.40	33.81	51.92	85.74	31.79	37.00	3.12
3/20/2018	71.14	39.68	53.29	49.35	33.84	51.87	85.85	31.78	37.00	3.12
3/19/2018	71.22	39.83	53.58	49.45	33.99	52.34	86.23	31.89	37.10	3.09
3/16/2018	71.07	40.13	53.22	49.60	34.13	51.90	86.10	32.00	37.00	3.08
3/15/2018	69.48	39.66	52.67	48.70	33.77	51.16	84.03	31.62	36.65	3.05
3/14/2018	69.19	39.54	52.00	48.90	33.65	51.12	83.61	31.79	36.55	3.05
3/13/2018	68.68	39.30	51.60	48.35	33.68	51.42	82.98	31.52	36.15	3.1
3/12/2018	68.71	39.21	52.31	48.65	33.72	51.67	83.32	31.45	36.20	3.13
3/9/2018	68.08	38.71	52.04	48.50	33.30	51.07	81.95	31.35	35.70	3.16
3/8/2018	67.70	38.32	51.80	48.75	32.89	50.89	81.45	31.22	35.45	3.13
3/7/2018	67.86	38.06	51.52	48.75	32.82	50.84	81.36	30.88	35.10	3.15
3/6/2018	67.19	38.17	52.25	48.55	33.11	51.04	81.86	31.20	35.35	3.14
3/5/2018	68.53	38.93	52.26	49.40	33.50	51.93	82.78	31.92	36.05	3.16
3/2/2018	68.58	38.22	51.33	48.60	33.00	51.06	81.61	31.19	35.85	3.14
3/1/2018	68.60	38.49	50.97	48.60	33.08	51.05	81.48	31.54	35.40	3.09
2/28/2018	68.15	38.65	50.79	48.60	32.96	51.08	81.05	31.34	35.20	3.13
2/27/2018	68.25	38.80	51.60	49.05	33.21	51.11	82.45	31.58	35.50	3.17
2/26/2018	69.44	39.53	51.98	50.50	33.68	51.74	83.91	32.28	36.30	3.15
2/23/2018	69.98	39.42	51.94	50.55	33.80	52.50	84.98	32.95	36.50	3.16
2/22/2018	68.19	38.60	50.86	49.80	33.15	51.19	82.90	31.47	35.45	3.21
2/21/2018	67.80	38.62	50.66	49.90	33.20	51.15	82.61	30.82	35.45	3.22
2/20/2018	68.74	39.14	51.54	50.25	33.35	51.32	83.70	31.21	35.30	3.15
2/16/2018	69.34	39.75	52.39	51.30	33.70	52.27	85.27	31.56	35.75	3.13
2/15/2018	68.48	39.05	52.19	50.85	33.77	51.59	84.72	31.34	35.60	3.15
2/14/2018	68.05	38.11	51.76	50.00	32.62	50.92	82.80	30.78	34.60	3.18
2/13/2018	69.45	38.63	52.30	50.80	32.76	51.82	83.47	30.96	34.95	3.11
2/12/2018	69.71	38.48	53.17	50.70	32.86	52.22	83.33	30.87	35.20	3.14
2/9/2018	69.89	38.42	52.04	50.75	32.58	52.13	83.57	30.39	35.00	3.14
2/8/2018	68.56	37.14	50.72	49.50	31.73	50.33	82.03	29.60	33.80	3.14
2/7/2018	68.73	37.50	51.78	49.70	32.06	50.81	82.25	30.28	34.45	3.12
2/6/2018	68.37	37.51	51.75	49.50	32.14	50.89	81.75	30.28	34.65	3.06
2/5/2018	68.70	38.22	52.41	50.25	32.76	51.65	82.29	30.69	35.40	3.04
2/2/2018	70.42	38.91	53.90	51.05	33.58	52.86	83.39	31.35	36.50	3.08
2/1/2018	70.56	39.08	54.92	51.45	33.86	53.44	84.93	31.93	36.85	3.01
1/31/2018	72.44	39.75	55.55	52.20	34.11	54.34	86.28	32.20	38.10	2.95
1/30/2018	71.85	39.26	55.52	51.60	33.95	53.80	85.33	31.71	37.70	2.98
1/29/2018	71.62	39.61	55.77	51.15	34.16	53.72	84.89	31.71	37.60	2.94
1/26/2018	72.84	40.30	57.10	51.60	34.50	54.36	86.07	32.14	38.10	2.91
1/25/2018	73.41	40.39	56.12	52.05	34.75	54.44	86.65	32.30	37.95	2.89
1/24/2018	72.42	39.85	55.97	51.35	34.41	53.30	84.90	32.13	37.65	2.93
1/23/2018	73.06	40.16	55.58	51.75	34.58	53.47	85.20	31.86	37.65	2.9
1/22/2018	72.12	39.55	54.75	51.65	34.38	53.35	83.94	31.57	37.05	2.93
1/19/2018	71.98	39.41	53.66	51.65	34.45	53.21	83.86	31.42	37.00	2.91
1/18/2018	73.22	39.68	53.21	51.30	34.46	53.25	83.71	31.33	36.20	2.9
1/17/2018	73.85	40.06	53.46	51.90	34.62	53.87	84.33	31.40	36.15	2.84
1/16/2018	73.48	39.56	53.62	51.00	34.21	53.91	83.25	30.98	35.55	2.83
1/12/2018	73.00	39.53	54.44	51.05	34.41	55.40	83.32	30.74	35.70	2.85
1/11/2018	72.54	39.84	54.99	51.45	34.49	56.08	83.29	31.25	36.55	2.91
1/10/2018	72.72	40.19	55.12	51.75	34.60	56.21	84.04	30.89	37.75	2.88
1/9/2018	73.38	40.91	54.78	53.30	35.16	57.42	85.42	32.10	39.00	2.88

1/8/2018	74.05	41.54	57.85	55.00	35.34	57.80	88.10	32.75	39.90	2.81
1/5/2018	73.55	41.08	57.41	54.25	34.97	57.41	87.69	32.50	39.40	2.81
1/4/2018	72.92	41.25	58.27	54.00	34.98	57.45	88.31	32.60	39.50	2.79
1/3/2018	73.40	41.74	58.62	54.05	35.29	57.81	88.98	32.66	39.65	2.78
1/2/2018	73.80	42.11	59.14	54.70	35.57	58.30	89.84	32.67	39.95	2.81
12/29/2017	74.36	42.61	60.11	55.35	36.15	59.70	91.36	32.91	40.45	2.74
12/28/2017	74.31	42.66	59.91	55.30	36.31	59.61	91.59	33.00	40.60	2.75
12/27/2017	73.71	42.42	59.06	55.05	36.05	58.99	90.72	32.75	40.32	2.75
12/26/2017	73.04	42.19	58.64	54.60	35.99	58.82	89.86	32.83	40.20	2.82
12/22/2017	73.45	42.50	59.02	55.15	36.32	59.27	90.66	33.01	40.90	2.83
12/21/2017	73.60	42.32	58.20	55.00	35.88	58.52	90.42	32.66	41.25	2.84
12/20/2017	74.13	42.51	58.60	55.80	36.00	59.47	91.11	32.97	42.10	2.88
12/19/2017	74.75	42.77	59.07	56.45	36.32	59.92	92.65	33.34	42.50	2.82
12/18/2017	76.35	43.60	59.76	58.20	36.72	60.89	94.57	33.81	43.35	2.74
12/15/2017	77.90	44.43	60.02	59.10	36.93	61.60	95.51	34.15	43.95	2.68
12/14/2017	76.76	43.95	59.47	58.05	36.71	60.91	94.54	33.85	43.35	2.71
12/13/2017	77.56	44.29	60.18	58.75	37.22	61.94	95.22	33.89	43.60	2.74
12/12/2017	77.37	44.01	59.73	58.10	37.33	62.12	95.00	34.05	43.85	2.79
12/11/2017	79.16	45.08	59.97	58.80	37.85	62.95	96.75	34.55	45.20	2.77
12/8/2017	79.33	44.94	59.65	58.90	37.89	63.28	97.16	34.46	45.10	2.77
12/7/2017	79.34	44.64	58.94	58.80	37.55	63.12	97.23	34.65	44.80	2.76
12/6/2017	79.42	44.54	57.92	59.20	37.67	63.15	96.90	34.13	44.85	2.71
12/5/2017	78.65	44.34	57.44	58.95	37.89	62.50	96.28	34.27	44.75	2.73
12/4/2017	80.39	44.69	58.12	60.05	38.25	63.50	97.86	35.05	45.40	2.77
12/1/2017	80.21	44.83	58.24	60.25	38.10	63.76	98.23	35.23	45.50	2.76
11/30/2017	80.50	45.11	58.51	60.90	38.35	64.26	98.81	35.76	45.50	2.83
11/29/2017	80.10	44.90	58.38	60.55	38.13	63.46	97.94	35.28	45.10	2.81
11/28/2017	80.20	44.78	58.24	60.60	37.72	63.17	97.59	35.40	45.15	2.77
11/27/2017	79.03	44.61	58.05	59.70	37.14	62.59	96.60	35.13	44.90	2.76
11/24/2017	78.18	44.22	58.02	59.65	36.87	62.22	96.55	34.90	44.50	2.76
11/22/2017	77.88	44.19	57.97	59.55	36.67	62.00	96.36	34.91	44.45	2.75
11/21/2017	78.51	44.15	58.20	60.45	36.86	62.13	97.64	34.82	45.05	2.76
11/20/2017	77.44	44.26	58.63	59.90	37.04	61.56	97.60	34.94	44.80	2.78
11/17/2017	77.50	44.40	58.93	60.20	37.05	61.60	97.23	35.20	44.75	2.78
11/16/2017	78.01	44.63	59.32	60.65	36.84	61.75	97.43	35.44	45.15	2.81
11/15/2017	77.39	44.71	58.35	59.85	37.02	61.50	96.95	35.55	44.50	2.77
11/14/2017	78.49	45.18	58.80	59.60	37.35	62.08	97.87	35.85	44.85	2.84
11/13/2017	77.05	44.30	58.33	58.00	36.84	60.76	95.93	35.12	43.80	2.87
11/10/2017	76.34	43.68	57.59	57.75	36.23	60.34	95.17	35.01	43.40	2.88
11/9/2017	76.93	44.10	58.20	58.00	36.40	60.73	95.29	35.53	43.50	2.81
11/8/2017	77.20	44.07	57.97	58.60	36.50	60.87	95.10	35.73	43.40	2.79
11/7/2017	77.25	44.17	58.84	57.95	36.55	60.71	94.61	35.84	43.30	2.77
11/6/2017	77.08	43.59	59.74	57.45	36.25	60.14	93.37	35.38	42.40	2.8
11/3/2017	76.93	43.83	61.23	57.60	36.46	59.78	92.71	35.63	42.40	2.82
11/2/2017	78.07	43.06	63.75	57.85	36.31	59.35	92.60	36.06	42.75	2.83
11/1/2017	77.32	43.07	64.45	56.20	36.13	58.87	91.32	36.60	42.50	2.85
10/31/2017	78.35	43.26	65.26	57.50	36.46	59.28	92.03	36.84	43.40	2.88
10/30/2017	77.64	43.18	65.36	58.00	36.18	59.20	91.75	36.90	42.90	2.88
10/27/2017	79.69	43.75	65.08	58.40	36.25	59.22	93.18	37.08	43.25	2.93
10/26/2017	79.03	43.38	65.09	58.00	35.63	58.31	91.64	36.82	42.15	2.96
10/25/2017	78.80	43.25	64.89	57.80	35.50	58.13	91.33	36.73	42.30	2.95
10/24/2017	78.70	43.48	66.31	57.45	35.77	58.60	91.35	37.00	42.25	2.92
10/23/2017	78.62	43.77	67.02	57.35	35.73	58.87	91.60	37.23	42.20	2.89
10/20/2017	78.93	43.87	66.97	57.25	35.45	58.70	91.68	37.09	42.15	2.89
10/19/2017	79.09	43.85	67.30	57.40	35.43	58.75	91.38	36.92	41.90	2.83
10/18/2017	79.34	43.38	67.26	57.20	35.07	58.71	91.18	36.87	41.55	2.85
10/17/2017	78.78	43.44	67.60	57.15	34.89	58.63	90.59	36.92	41.35	2.8
10/16/2017	78.01	43.12	67.69	57.00	34.67	58.50	90.18	36.72	40.95	2.82
10/13/2017	78.38	43.05	67.67	58.10	34.33	58.44	90.34	36.82	41.35	2.81
10/12/2017	78.81	43.01	68.42	58.20	34.35	58.66	90.67	36.85	41.35	2.86
10/11/2017	79.06	42.66	68.00	57.85	34.28	58.00	89.54	36.47	41.30	2.88
10/10/2017	78.81	42.34	68.04	57.65	34.07	57.91	89.25	36.20	40.80	2.88
10/9/2017	78.08	41.99	67.09	57.05	33.80	57.44	88.38	35.75	40.45	#N/A N/A
10/6/2017	78.31	41.92	67.08	56.85	33.90	57.37	88.44	35.58	40.70	2.91
10/5/2017	78.49	41.90	69.15	56.75	33.78	57.73	88.69	36.32	40.75	2.89
10/4/2017	78.49	41.95	69.73	56.70	33.82	57.66	89.15	36.15	40.65	2.87
10/3/2017	77.55	41.38	69.08	56.15	33.64	57.30	88.42	36.16	40.20	2.87
10/2/2017	77.82	41.60	68.62	56.05	33.64	57.27	88.78	36.17	40.80	2.87
9/29/2017	77.29	41.57	68.87	55.25	33.37	56.94	87.93	36.03	40.30	2.86
9/28/2017	77.84	41.70	69.33	55.60	33.67	57.50	88.58	36.18	41.00	2.87
9/27/2017	77.70	41.58	69.07	55.30	33.55	57.42	88.35	36.02	41.20	2.86
9/26/2017	77.42	42.25	68.96	55.20	33.70	57.78	88.41	36.18	41.20	2.78
9/25/2017	77.56	42.25	69.23	55.30	33.80	57.87	88.67	36.27	41.65	2.76
9/22/2017	76.91	41.73	68.60	54.65	33.48	57.75	87.75	35.84	41.30	2.8
9/21/2017	77.15	42.06	68.73	54.90	33.56	58.64	88.52	35.88	41.60	2.8
9/20/2017	77.29	42.15	68.51	54.40	33.37	58.34	88.60	36.11	41.60	2.82
9/19/2017	77.68	42.53	69.00	54.85	33.37	58.47	89.11	36.25	41.70	2.81
9/18/2017	77.65	42.49	68.95	54.80	33.49	58.41	89.18	36.22	41.58	2.8
9/15/2017	78.41	42.90	69.63	55.15	33.72	58.96	90.06	36.31	42.50	2.77
9/14/2017	78.20	42.92	69.82	55.15	33.82	59.23	89.96	36.27	42.30	2.77
9/13/2017	77.56	42.45	69.48	55.00	33.74	59.22	89.50	35.95	41.80	2.79
9/12/2017	77.75	42.75	69.50	55.30	33.86	59.35	89.87	36.16	42.00	2.78
9/11/2017	79.14	43.60	70.83	56.35	34.42	60.65	91.88	36.59	42.95	2.75
9/8/2017	79.14	43.19	70.22	55.95	34.13	60.24	91.40	36.15	42.55	2.67
9/7/2017	78.65	42.95	69.93	55.50	33.60	59.99	90.83	36.02	42.55	2.66
9/6/2017	77.63	42.60	69.80	55.05	33.48	59.70	89.72	35.70	42.30	2.72
9/5/2017	77.83	42.91	70.74	55.65	33.48	60.16	89.83	35.58	42.40	2.69
9/1/2017	77.52	42.57	70.42	55.40	33.51	60.23	89.32	35.76	42.55	2.77
8/31/2017	77.33	42.74	70.38	55.55	33.42	60.32	88.98	35.72	42.40	2.73

ALE US Equity
DVD_HIST

4/25/2018	5/14/2018	5/15/2018	6/1/2018	0.56	Quarter	Regular Cash
1/24/2018	2/14/2018	2/15/2018	3/1/2018	0.56	Quarter	Regular Cash
10/25/2017	11/14/2017	11/15/2017	12/1/2017	0.535	Quarter	Regular Cash
7/27/2017	8/11/2017	8/15/2017	9/1/2017	0.535	Quarter	Regular Cash
4/26/2017	5/11/2017	5/15/2017	6/1/2017	0.535	Quarter	Regular Cash
1/25/2017	2/13/2017	2/15/2017	3/1/2017	0.535	Quarter	Regular Cash
10/28/2016	11/10/2016	11/15/2016	12/1/2016	0.52	Quarter	Regular Cash
7/28/2016	8/11/2016	8/15/2016	9/1/2016	0.52	Quarter	Regular Cash
4/21/2016	5/12/2016	5/16/2016	6/1/2016	0.52	Quarter	Regular Cash
1/22/2016	2/11/2016	2/16/2016	3/1/2016	0.52	Quarter	Regular Cash
11/2/2015	11/12/2015	11/16/2015	12/1/2015	0.505	Quarter	Regular Cash
7/31/2015	8/12/2015	8/14/2015	9/1/2015	0.505	Quarter	Regular Cash
4/30/2015	5/13/2015	5/15/2015	6/1/2015	0.505	Quarter	Regular Cash
1/23/2015	2/11/2015	2/16/2015	3/1/2015	0.505	Quarter	Regular Cash
10/30/2014	11/12/2014	11/14/2014	12/1/2014	0.49	Quarter	Regular Cash
7/31/2014	8/13/2014	8/15/2014	9/1/2014	0.49	Quarter	Regular Cash
5/1/2014	5/13/2014	5/15/2014	6/1/2014	0.49	Quarter	Regular Cash
1/30/2014	2/12/2014	2/14/2014	3/1/2014	0.49	Quarter	Regular Cash
10/28/2013	11/13/2013	11/15/2013	12/1/2013	0.475	Quarter	Regular Cash
7/29/2013	8/13/2013	8/15/2013	9/1/2013	0.475	Quarter	Regular Cash
5/1/2013	5/13/2013	5/15/2013	6/1/2013	0.475	Quarter	Regular Cash
1/23/2013	2/13/2013	2/15/2013	3/1/2013	0.475	Quarter	Regular Cash
10/29/2012	11/13/2012	11/15/2012	12/1/2012	0.46	Quarter	Regular Cash
7/26/2012	8/13/2012	8/15/2012	9/1/2012	0.46	Quarter	Regular Cash
4/26/2012	5/11/2012	5/15/2012	6/1/2012	0.46	Quarter	Regular Cash
1/26/2012	2/13/2012	2/15/2012	3/1/2012	0.46	Quarter	Regular Cash
10/31/2011	11/10/2011	11/15/2011	12/1/2011	0.445	Quarter	Regular Cash
7/20/2011	8/11/2011	8/15/2011	9/1/2011	0.445	Quarter	Regular Cash
4/20/2011	5/12/2011	5/16/2011	6/1/2011	0.445	Quarter	Regular Cash
1/20/2011	2/11/2011	2/15/2011	3/1/2011	0.445	Quarter	Regular Cash
10/20/2010	11/10/2010	11/15/2010	12/1/2010	0.44	Quarter	Regular Cash
7/21/2010	8/12/2010	8/16/2010	9/1/2010	0.44	Quarter	Regular Cash
4/21/2010	5/12/2010	5/14/2010	6/1/2010	0.44	Quarter	Regular Cash
1/21/2010	2/10/2010	2/15/2010	3/1/2010	0.44	Quarter	Regular Cash
10/22/2009	11/12/2009	11/16/2009	12/1/2009	0.44	Quarter	Regular Cash
7/22/2009	8/12/2009	8/14/2009	9/1/2009	0.44	Quarter	Regular Cash
4/23/2009	5/13/2009	5/15/2009	6/1/2009	0.44	Quarter	Regular Cash
1/22/2009	2/11/2009	2/16/2009	3/1/2009	0.44	Quarter	Regular Cash
10/24/2008	11/12/2008	11/14/2008	12/1/2008	0.43	Quarter	Regular Cash
7/24/2008	8/13/2008	8/15/2008	9/1/2008	0.43	Quarter	Regular Cash
4/24/2008	5/13/2008	5/15/2008	6/1/2008	0.43	Quarter	Regular Cash
1/24/2008	2/13/2008	2/15/2008	3/1/2008	0.43	Quarter	Regular Cash
10/18/2007	11/13/2007	11/15/2007	12/1/2007	0.41	Quarter	Regular Cash
7/19/2007	8/13/2007	8/15/2007	9/1/2007	0.41	Quarter	Regular Cash
4/27/2007	5/11/2007	5/15/2007	6/1/2007	0.41	Quarter	Regular Cash
1/26/2007	2/13/2007	2/15/2007	3/1/2007	0.41	Quarter	Regular Cash
10/30/2006	11/13/2006	11/15/2006	12/1/2006	0.3625	Quarter	Regular Cash
7/28/2006	8/11/2006	8/15/2006	9/1/2006	0.3625	Quarter	Regular Cash
4/27/2006	5/11/2006	5/15/2006	6/1/2006	0.3625	Quarter	Regular Cash
1/26/2006	2/13/2006	2/15/2006	3/1/2006	0.3625	Quarter	Regular Cash
10/28/2005	11/10/2005	11/15/2005	12/1/2005	0.315	Quarter	Regular Cash
7/29/2005	8/11/2005	8/15/2005	9/1/2005	0.315	Quarter	Regular Cash
4/29/2005	5/12/2005	5/16/2005	6/1/2005	0.315	Quarter	Regular Cash
2/4/2005	2/11/2005	2/15/2005	3/1/2005	0.3	Quarter	Regular Cash

10/22/2004	11/10/2004	11/15/2004	12/1/2004	0.3	Quarter	Regular Cash
7/22/2004	8/12/2004	8/16/2004	9/1/2004	0.8475	Quarter	Regular Cash
4/22/2004	5/12/2004	5/14/2004	6/1/2004	0.8475	Quarter	Regular Cash
1/22/2004	2/11/2004	2/16/2004	3/1/2004	0.8475	Quarter	Regular Cash
10/24/2003	11/12/2003	11/14/2003	12/1/2003	0.8475	Quarter	Regular Cash
7/24/2003	8/13/2003	8/15/2003	9/1/2003	0.8475	Quarter	Regular Cash
4/25/2003	5/13/2003	5/15/2003	6/1/2003	0.8475	Quarter	Regular Cash
1/24/2003	2/12/2003	2/14/2003	3/1/2003	0.8475	Quarter	Regular Cash
10/18/2002	11/13/2002	11/15/2002	12/1/2002	0.825	Quarter	Regular Cash
7/19/2002	8/13/2002	8/15/2002	9/1/2002	0.825	Quarter	Regular Cash
4/25/2002	5/13/2002	5/15/2002	6/1/2002	0.825	Quarter	Regular Cash
1/24/2002	2/13/2002	2/15/2002	3/1/2002	0.825	Quarter	Regular Cash
10/19/2001	11/13/2001	11/15/2001	12/1/2001	0.8025	Quarter	Regular Cash
7/19/2001	8/13/2001	8/15/2001	9/1/2001	0.8025	Quarter	Regular Cash
4/18/2001	5/11/2001	5/15/2001	6/1/2001	0.8025	Quarter	Regular Cash
1/18/2001	2/13/2001	2/15/2001	3/1/2001	0.8025	Quarter	Regular Cash
10/18/2000	11/13/2000	11/15/2000	12/1/2000	0.8025	Quarter	Regular Cash
7/19/2000	8/11/2000	8/15/2000	9/1/2000	0.8025	Quarter	Regular Cash
4/19/2000	5/11/2000	5/15/2000	6/1/2000	0.8025	Quarter	Regular Cash
1/18/2000	2/11/2000	2/15/2000	3/1/2000	0.8025	Quarter	Regular Cash
10/27/1999	11/10/1999	11/15/1999	12/1/1999	0.8025	Quarter	Regular Cash
7/21/1999	8/12/1999	8/16/1999	9/1/1999	0.8025	Quarter	Regular Cash
4/21/1999	5/12/1999	5/14/1999	6/1/1999	0.8025	Quarter	Regular Cash
1/18/1999	2/11/1999	2/16/1999	3/1/1999	0.8025	Quarter	Regular Cash
10/28/1998	11/12/1998	11/16/1998	12/1/1998	0.765	Quarter	Regular Cash
7/22/1998	8/12/1998	8/14/1998	9/1/1998	0.765	Quarter	Regular Cash
4/22/1998	5/13/1998	5/15/1998	6/1/1998	0.765	Quarter	Regular Cash
1/27/1998	2/11/1998	2/16/1998	3/1/1998	0.765	Quarter	Regular Cash
10/29/1997	11/12/1997	11/14/1997	12/1/1997	0.765	Quarter	Regular Cash
7/23/1997	8/13/1997	8/15/1997	9/1/1997	0.765	Quarter	Regular Cash
4/23/1997	5/13/1997	5/15/1997	6/1/1997	0.765	Quarter	Regular Cash
1/28/1997	2/12/1997	2/14/1997	3/1/1997	0.765	Quarter	Regular Cash
10/23/1996	11/13/1996	11/15/1996	12/1/1996	0.765	Quarter	Regular Cash
7/24/1996	8/13/1996	8/15/1996	9/1/1996	0.765	Quarter	Regular Cash
4/24/1996	5/13/1996	5/15/1996	6/1/1996	0.765	Quarter	Regular Cash
1/23/1996	2/13/1996	2/15/1996	3/1/1996	0.765	Quarter	Regular Cash
10/25/1995	11/13/1995	11/15/1995	12/1/1995	0.765	Quarter	Regular Cash
7/26/1995	8/11/1995	8/15/1995	9/1/1995	0.765	Quarter	Regular Cash
4/25/1995	5/9/1995	5/15/1995	6/1/1995	0.765	Quarter	Regular Cash
1/25/1995	2/9/1995	2/15/1995	3/1/1995	0.765	Quarter	Regular Cash
10/26/1994	11/8/1994	11/15/1994	12/1/1994	0.7575	Quarter	Regular Cash
7/27/1994	8/9/1994	8/15/1994	9/1/1994	0.7575	Quarter	Regular Cash
4/27/1994	5/10/1994	5/16/1994	6/1/1994	0.7575	Quarter	Regular Cash
1/26/1994	2/9/1994	2/15/1994	3/1/1994	0.7575	Quarter	Regular Cash
10/27/1993	11/8/1993	11/15/1993	12/1/1993	0.7425	Quarter	Regular Cash
7/21/1993	8/10/1993	8/16/1993	9/1/1993	0.7425	Quarter	Regular Cash
4/21/1993	5/10/1993	5/14/1993	6/1/1993	0.7425	Quarter	Regular Cash
2/2/1993	2/9/1993	2/16/1993	3/1/1993	0.7425	Quarter	Regular Cash
10/21/1992	11/9/1992	11/16/1992	12/1/1992	0.7275	Quarter	Regular Cash
7/22/1992	8/10/1992	8/14/1992	9/1/1992	0.7275	Quarter	Regular Cash
4/22/1992	5/11/1992	5/15/1992	6/1/1992	0.7275	Quarter	Regular Cash
1/22/1992	2/10/1992	2/14/1992	3/1/1992	0.7275	Quarter	Regular Cash
10/23/1991	11/8/1991	11/15/1991	12/1/1991	0.7125	Quarter	Regular Cash
7/24/1991	8/9/1991	8/15/1991	9/1/1991	0.7125	Quarter	Regular Cash
4/24/1991	5/9/1991	5/15/1991	6/1/1991	0.7125	Quarter	Regular Cash
1/23/1991	2/11/1991	2/15/1991	3/1/1991	0.7125	Quarter	Regular Cash
10/24/1990	11/8/1990	11/15/1990	12/1/1990	0.6975	Quarter	Regular Cash
7/25/1990	8/9/1990	8/15/1990	9/1/1990	0.6975	Quarter	Regular Cash
4/25/1990	5/9/1990	5/15/1990	6/1/1990	0.6975	Quarter	Regular Cash
1/24/1990	2/9/1990	2/15/1990	3/1/1990	0.6975	Quarter	Regular Cash
10/25/1989	11/9/1989	11/15/1989	12/1/1989	0.6675	Quarter	Regular Cash
7/26/1989	8/9/1989	8/15/1989	9/1/1989	0.6675	Quarter	Regular Cash
4/26/1989	5/9/1989	5/15/1989	6/1/1989	0.6675	Quarter	Regular Cash
1/25/1989	2/9/1989	2/15/1989	3/1/1989	0.6675	Quarter	Regular Cash
10/26/1988	11/8/1988	11/15/1988	12/1/1988	0.645	Quarter	Regular Cash
7/27/1988	8/9/1988	8/15/1988	9/1/1988	0.645	Quarter	Regular Cash

4/28/1988	5/10/1988	5/16/1988	6/1/1988	0.645	Quarter	Regular Cash
1/27/1988	2/9/1988	2/16/1988	3/1/1988	0.645	Quarter	Regular Cash
10/21/1987	11/9/1987	11/16/1987	12/1/1987	0.6225	Quarter	Regular Cash
7/22/1987	8/10/1987	8/14/1987	9/1/1987	0.6225	Quarter	Regular Cash
4/22/1987	5/11/1987	5/15/1987	6/1/1987	0.6225	Quarter	Regular Cash
1/28/1987	2/9/1987	2/16/1987	3/1/1987	0.6225	Quarter	Regular Cash
10/22/1986	11/7/1986	11/14/1986	12/1/1986	0.57	Quarter	Regular Cash
7/23/1986	8/11/1986	8/15/1986	9/1/1986	0.57	Quarter	Regular Cash
4/23/1986	5/9/1986	5/15/1986	6/1/1986	0.57	Quarter	Regular Cash
1/29/1986	2/10/1986	2/14/1986	3/1/1986	0.57	Quarter	Regular Cash
10/23/1985	11/8/1985	11/15/1985	12/1/1985	0.5175	Quarter	Regular Cash
7/24/1985	8/9/1985	8/15/1985	9/1/1985	0.5175	Quarter	Regular Cash
4/24/1985	5/9/1985	5/15/1985	6/1/1985	0.5175	Quarter	Regular Cash
1/30/1985	2/8/1985	2/15/1985	3/1/1985	0.5175	Quarter	Regular Cash
10/26/1984	11/8/1984	11/15/1984	12/1/1984	0.48	Quarter	Regular Cash
7/27/1984	8/9/1984	8/15/1984	9/1/1984	0.48	Quarter	Regular Cash
4/27/1984	5/9/1984	5/15/1984	6/1/1984	0.48	Quarter	Regular Cash
1/26/1984	2/8/1984	2/15/1984	3/1/1984	0.48	Quarter	Regular Cash
10/31/1983	11/7/1983	11/15/1983	12/1/1983	0.45	Quarter	Regular Cash
7/29/1983	8/9/1983	8/15/1983	9/1/1983	0.45	Quarter	Regular Cash
4/29/1983	5/10/1983	5/16/1983	6/1/1983	0.45	Quarter	Regular Cash
1/27/1983	2/9/1983	2/15/1983	3/1/1983	0.45	Quarter	Regular Cash
10/29/1982	11/8/1982	11/15/1982	12/1/1982	0.4275	Quarter	Regular Cash
7/30/1982	8/10/1982	8/16/1982	9/1/1982	0.4275	Quarter	Regular Cash
4/30/1982	5/10/1982	5/14/1982	6/1/1982	0.4275	Quarter	Regular Cash
1/28/1982	2/8/1982	2/16/1982	3/1/1982	0.4275	Quarter	Regular Cash
10/30/1981	11/4/1981	11/10/1981	12/1/1981	0.3975	Quarter	Regular Cash
7/31/1981	8/4/1981	8/10/1981	9/1/1981	0.3975	Quarter	Regular Cash
4/24/1981	5/5/1981	5/11/1981	6/1/1981	0.3975	Quarter	Regular Cash
2/4/1981	2/6/1981	2/13/1981	3/1/1981	0.3975	Quarter	Regular Cash
10/31/1980	11/3/1980	11/10/1980	12/1/1980	0.3825	Quarter	Regular Cash
7/31/1980	8/5/1980	8/11/1980	9/1/1980	0.3825	Quarter	Regular Cash
4/23/1980	5/6/1980	5/12/1980	5/30/1980	0.3825	Quarter	Regular Cash
1/31/1980	2/5/1980	2/11/1980	2/29/1980	0.3825	Quarter	Regular Cash

LNT US Equity
DVD_HIST

4/16/2018	4/27/2018	4/30/2018	5/15/2018	0.335	Quarter	Regular Cash
1/15/2018	1/30/2018	1/31/2018	2/15/2018	0.335	Quarter	Regular Cash
1/19/2018	1/30/2018	1/31/2018	2/15/2018	0.0005	None	Rights Redemption
10/16/2017	10/30/2017	10/31/2017	11/15/2017	0.315	Quarter	Regular Cash
7/17/2017	7/27/2017	7/31/2017	8/15/2017	0.315	Quarter	Regular Cash
4/7/2017	4/26/2017	4/28/2017	5/15/2017	0.315	Quarter	Regular Cash
1/13/2017	1/27/2017	1/31/2017	2/15/2017	0.315	Quarter	Regular Cash
10/7/2016	10/27/2016	10/31/2016	11/15/2016	0.2938	Quarter	Regular Cash
7/8/2016	7/27/2016	7/29/2016	8/15/2016	0.2938	Quarter	Regular Cash
4/8/2016	4/27/2016	4/29/2016	5/13/2016	0.2938	Quarter	Regular Cash
1/15/2016	1/27/2016	1/29/2016	2/12/2016	0.2938	Quarter	Regular Cash
10/9/2015	10/28/2015	10/30/2015	11/13/2015	0.275	Quarter	Regular Cash
7/10/2015	7/29/2015	7/31/2015	8/14/2015	0.275	Quarter	Regular Cash
4/10/2015	4/28/2015	4/30/2015	5/15/2015	0.275	Quarter	Regular Cash
1/16/2015	1/28/2015	1/30/2015	2/13/2015	0.275	Quarter	Regular Cash
10/10/2014	10/29/2014	10/31/2014	11/14/2014	0.255	Quarter	Regular Cash
7/11/2014	7/29/2014	7/31/2014	8/15/2014	0.255	Quarter	Regular Cash
4/11/2014	4/28/2014	4/30/2014	5/15/2014	0.255	Quarter	Regular Cash
1/17/2014	1/29/2014	1/31/2014	2/14/2014	0.255	Quarter	Regular Cash
10/1/2013	10/29/2013	10/31/2013	11/15/2013	0.235	Quarter	Regular Cash
7/12/2013	7/29/2013	7/31/2013	8/15/2013	0.235	Quarter	Regular Cash
4/12/2013	4/26/2013	4/30/2013	5/15/2013	0.235	Quarter	Regular Cash
1/11/2013	1/29/2013	1/31/2013	2/15/2013	0.235	Quarter	Regular Cash
10/12/2012	10/29/2012	10/31/2012	11/15/2012	0.225	Quarter	Regular Cash
7/13/2012	7/27/2012	7/31/2012	8/15/2012	0.225	Quarter	Regular Cash
4/13/2012	4/26/2012	4/30/2012	5/15/2012	0.225	Quarter	Regular Cash
1/13/2012	1/27/2012	1/31/2012	2/15/2012	0.225	Quarter	Regular Cash
10/12/2011	10/27/2011	10/31/2011	11/15/2011	0.2125	Quarter	Regular Cash
7/15/2011	7/27/2011	7/29/2011	8/15/2011	0.2125	Quarter	Regular Cash
4/15/2011	4/27/2011	4/29/2011	5/13/2011	0.2125	Quarter	Regular Cash
1/14/2011	1/27/2011	1/31/2011	2/15/2011	0.2125	Quarter	Regular Cash
10/15/2010	10/27/2010	10/29/2010	11/15/2010	0.1975	Quarter	Regular Cash
7/16/2010	7/28/2010	7/30/2010	8/13/2010	0.1975	Quarter	Regular Cash
4/16/2010	4/28/2010	4/30/2010	5/14/2010	0.1975	Quarter	Regular Cash
1/15/2010	1/27/2010	1/29/2010	2/12/2010	0.1975	Quarter	Regular Cash
10/16/2009	10/28/2009	10/30/2009	11/13/2009	0.1875	Quarter	Regular Cash
7/17/2009	7/29/2009	7/31/2009	8/14/2009	0.1875	Quarter	Regular Cash
4/17/2009	4/28/2009	4/30/2009	5/15/2009	0.1875	Quarter	Regular Cash
1/16/2009	1/28/2009	1/30/2009	2/13/2009	0.1875	Quarter	Regular Cash
10/17/2008	10/29/2008	10/31/2008	11/15/2008	0.175	Quarter	Regular Cash
7/15/2008	7/29/2008	7/31/2008	8/15/2008	0.175	Quarter	Regular Cash
4/11/2008	4/28/2008	4/30/2008	5/15/2008	0.175	Quarter	Regular Cash
1/18/2008	1/29/2008	1/31/2008	2/15/2008	0.175	Quarter	Regular Cash
10/12/2007	10/29/2007	10/31/2007	11/15/2007	0.1588	Quarter	Regular Cash
7/13/2007	7/27/2007	7/31/2007	8/15/2007	0.1588	Quarter	Regular Cash
4/13/2007	4/26/2007	4/30/2007	5/15/2007	0.1588	Quarter	Regular Cash
1/12/2007	1/29/2007	1/31/2007	2/15/2007	0.1588	Quarter	Regular Cash
10/13/2006	10/27/2006	10/31/2006	11/15/2006	0.1438	Quarter	Regular Cash
7/14/2006	7/27/2006	7/31/2006	8/15/2006	0.1438	Quarter	Regular Cash
4/14/2006	4/26/2006	4/28/2006	5/15/2006	0.1438	Quarter	Regular Cash
1/17/2006	1/27/2006	1/31/2006	2/15/2006	0.1438	Quarter	Regular Cash
10/14/2005	10/27/2005	10/31/2005	11/15/2005	0.1313	Quarter	Regular Cash
7/18/2005	7/27/2005	7/29/2005	8/15/2005	0.1313	Quarter	Regular Cash
4/15/2005	4/27/2005	4/29/2005	5/14/2005	0.1313	Quarter	Regular Cash

1/14/2005	1/27/2005	1/31/2005	2/15/2005	0.1313	Quarter	Regular Cash
10/11/2004	10/27/2004	10/29/2004	11/15/2004	0.1313	Quarter	Regular Cash
7/15/2004	7/28/2004	7/30/2004	8/14/2004	0.125	Quarter	Regular Cash
4/15/2004	4/28/2004	4/30/2004	5/15/2004	0.125	Quarter	Regular Cash
1/15/2004	1/28/2004	1/30/2004	2/14/2004	0.125	Quarter	Regular Cash
10/8/2003	10/29/2003	10/31/2003	11/15/2003	0.125	Quarter	Regular Cash
7/11/2003	7/29/2003	7/31/2003	8/15/2003	0.125	Quarter	Regular Cash
4/11/2003	4/28/2003	4/30/2003	5/15/2003	0.125	Quarter	Regular Cash
1/22/2003	1/29/2003	1/31/2003	2/15/2003	0.125	Quarter	Regular Cash
10/16/2002	10/29/2002	10/31/2002	11/15/2002	0.25	Quarter	Regular Cash
7/12/2002	7/29/2002	7/31/2002	8/15/2002	0.25	Quarter	Regular Cash
4/9/2002	4/26/2002	4/30/2002	5/15/2002	0.25	Quarter	Regular Cash
1/23/2002	1/29/2002	1/31/2002	2/15/2002	0.25	Quarter	Regular Cash
10/17/2001	10/29/2001	10/31/2001	11/15/2001	0.25	Quarter	Regular Cash
7/11/2001	7/27/2001	7/31/2001	8/15/2001	0.25	Quarter	Regular Cash
4/10/2001	4/26/2001	4/30/2001	5/15/2001	0.25	Quarter	Regular Cash
1/24/2001	1/29/2001	1/31/2001	2/15/2001	0.25	Quarter	Regular Cash
10/18/2000	10/27/2000	10/31/2000	11/15/2000	0.25	Quarter	Regular Cash
7/11/2000	7/27/2000	7/31/2000	8/15/2000	0.25	Quarter	Regular Cash
4/17/2000	4/26/2000	4/28/2000	5/15/2000	0.25	Quarter	Regular Cash
1/19/2000	1/27/2000	1/31/2000	2/15/2000	0.25	Quarter	Regular Cash
10/20/1999	10/27/1999	10/29/1999	11/15/1999	0.25	Quarter	Regular Cash
7/19/1999	7/28/1999	7/30/1999	8/14/1999	0.25	Quarter	Regular Cash
4/15/1999	4/28/1999	4/30/1999	5/15/1999	0.25	Quarter	Regular Cash
1/20/1999	1/27/1999	1/29/1999	2/13/1999	0.25	Quarter	Regular Cash
10/21/1998	10/28/1998	10/30/1998	11/14/1998	0.25	Quarter	Regular Cash
7/22/1998	7/29/1998	7/31/1998	8/15/1998	0.25	Quarter	Regular Cash
4/24/1998	4/30/1998	5/4/1998	5/15/1998	0.0715	Quarter	Regular Cash
3/27/1998	4/22/1998	4/20/1998	4/27/1998	0.1786	Quarter	Regular Cash
1/16/1998	1/22/1998	1/26/1998	2/14/1998	0.25	Quarter	Regular Cash
10/22/1997	10/29/1997	10/31/1997	11/15/1997	0.25	Quarter	Regular Cash
7/23/1997	7/31/1997	8/4/1997	8/15/1997	0.25	Quarter	Regular Cash
4/15/1997	4/28/1997	4/30/1997	5/15/1997	0.25	Quarter	Regular Cash
1/22/1997	1/29/1997	1/31/1997	2/15/1997	0.25	Quarter	Regular Cash
10/23/1996	10/30/1996	11/1/1996	11/15/1996	0.2463	Quarter	Regular Cash
7/25/1996	8/1/1996	8/5/1996	8/15/1996	0.2463	Quarter	Regular Cash
4/15/1996	4/26/1996	4/30/1996	5/15/1996	0.2463	Quarter	Regular Cash
1/24/1996	1/31/1996	2/2/1996	2/15/1996	0.2463	Quarter	Regular Cash
10/18/1995	10/27/1995	10/31/1995	11/15/1995	0.2425	Quarter	Regular Cash
7/12/1995	7/27/1995	7/31/1995	8/15/1995	0.2425	Quarter	Regular Cash
4/12/1995	4/24/1995	4/28/1995	5/15/1995	0.2425	Quarter	Regular Cash
1/18/1995	1/25/1995	1/31/1995	2/15/1995	0.2425	Quarter	Regular Cash
10/19/1994	10/25/1994	10/31/1994	11/15/1994	0.24	Quarter	Regular Cash
7/13/1994	7/25/1994	7/29/1994	8/15/1994	0.24	Quarter	Regular Cash
4/18/1994	4/25/1994	4/29/1994	5/14/1994	0.24	Quarter	Regular Cash
1/19/1994	1/25/1994	1/31/1994	2/15/1994	0.24	Quarter	Regular Cash
10/14/1993	10/25/1993	10/29/1993	11/15/1993	0.2375	Quarter	Regular Cash
7/14/1993	7/26/1993	7/30/1993	8/14/1993	0.2375	Quarter	Regular Cash
4/14/1993	4/26/1993	4/30/1993	5/15/1993	0.2375	Quarter	Regular Cash
1/13/1993	1/25/1993	1/29/1993	2/13/1993	0.2375	Quarter	Regular Cash
10/14/1992	10/26/1992	10/30/1992	11/14/1992	0.2325	Quarter	Regular Cash
7/15/1992	7/27/1992	7/31/1992	8/15/1992	0.2325	Quarter	Regular Cash
4/15/1992	4/24/1992	4/30/1992	5/15/1992	0.2325	Quarter	Regular Cash
1/15/1992	1/27/1992	1/31/1992	2/15/1992	0.2325	Quarter	Regular Cash
10/16/1991	10/25/1991	10/31/1991	11/15/1991	0.225	Quarter	Regular Cash
7/17/1991	7/25/1991	7/31/1991	8/15/1991	0.225	Quarter	Regular Cash
4/17/1991	4/24/1991	4/30/1991	5/15/1991	0.225	Quarter	Regular Cash
1/16/1991	1/25/1991	1/31/1991	2/15/1991	0.225	Quarter	Regular Cash
9/26/1990	10/25/1990	10/31/1990	11/15/1990	0.2175	Quarter	Regular Cash
6/27/1990	7/25/1990	7/31/1990	8/15/1990	0.2175	Quarter	Regular Cash
3/28/1990	4/24/1990	4/30/1990	5/15/1990	0.2175	Quarter	Regular Cash
1/17/1990	1/25/1990	1/31/1990	2/15/1990	0.2175	Quarter	Regular Cash
10/3/1989	10/25/1989	10/31/1989	11/15/1989	0.21	Quarter	Regular Cash
6/29/1989	7/25/1989	7/31/1989	8/15/1989	0.21	Quarter	Regular Cash
3/22/1989	4/24/1989	4/28/1989	5/15/1989	0.21	Quarter	Regular Cash
1/18/1989	1/25/1989	1/31/1989	2/15/1989	0.21	Quarter	Regular Cash

10/19/1988	10/25/1988	10/31/1988	11/15/1988	0.2025	Quarter	Regular Cash
7/13/1988	7/25/1988	7/29/1988	8/15/1988	0.2025	Quarter	Regular Cash
3/23/1988	4/25/1988	4/29/1988	5/14/1989	0.2025	Quarter	Regular Cash
10/19/1984	10/25/1984	10/31/1984	11/15/1984	0.16	Quarter	Regular Cash
7/19/1984	7/25/1984	7/31/1984	8/15/1984	0.16	Quarter	Regular Cash
4/23/1984	4/24/1984	4/30/1984	5/15/1984	0.155	Quarter	Regular Cash
1/19/1984	1/25/1984	1/31/1984	2/15/1984	0.155	Quarter	Regular Cash
9/30/1982	10/25/1982	10/29/1982	11/15/1982	0.14	Quarter	Regular Cash
7/23/1982	7/26/1982	7/30/1982	8/14/1982	0.14	Quarter	Regular Cash
4/23/1982	4/26/1982	4/30/1982	5/15/1982	0.135	Quarter	Regular Cash
1/21/1982	1/25/1982	1/29/1982	2/13/1982	0.135	Quarter	Regular Cash
9/28/1981	10/26/1981	10/30/1981	11/14/1981	0.13	Quarter	Regular Cash
7/23/1981	7/27/1981	7/31/1981	8/15/1981	0.13	Quarter	Regular Cash
4/24/1981	4/24/1981	4/30/1981	5/15/1981	0.125	Quarter	Regular Cash
1/26/1981	1/26/1981	1/30/1981	2/14/1981	0.125	Quarter	Regular Cash
10/24/1980	10/27/1980	10/31/1980	11/15/1980	0.12	Quarter	Regular Cash
7/24/1980	7/25/1980	7/31/1980	8/15/1980	0.12	Quarter	Regular Cash
3/26/1980	4/24/1980	4/30/1980	5/15/1980	0.115	Quarter	Regular Cash
1/25/1980	1/25/1980	1/31/1980	2/15/1980	0.115	Quarter	Regular Cash

BKH

BKH US Equity

DVD_HIST

4/23/2018	5/17/2018	5/18/2018	6/1/2018	0.475	Quarter	Regular Cash
2/1/2018	2/14/2018	2/15/2018	3/1/2018	0.475	Quarter	Regular Cash
11/1/2017	11/16/2017	11/17/2017	12/1/2017	0.475	Quarter	Regular Cash
7/26/2017	8/16/2017	8/18/2017	9/1/2017	0.445	Quarter	Regular Cash
4/24/2017	5/16/2017	5/18/2017	6/1/2017	0.445	Quarter	Regular Cash
1/25/2017	2/13/2017	2/15/2017	3/1/2017	0.445	Quarter	Regular Cash
10/25/2016	11/15/2016	11/17/2016	12/1/2016	0.42	Quarter	Regular Cash
7/29/2016	8/16/2016	8/18/2016	9/1/2016	0.42	Quarter	Regular Cash
4/25/2016	5/16/2016	5/18/2016	6/1/2016	0.42	Quarter	Regular Cash
1/27/2016	2/11/2016	2/16/2016	3/1/2016	0.42	Quarter	Regular Cash
10/27/2015	11/13/2015	11/17/2015	12/1/2015	0.405	Quarter	Regular Cash
7/28/2015	8/14/2015	8/18/2015	9/1/2015	0.405	Quarter	Regular Cash
4/27/2015	5/14/2015	5/18/2015	6/1/2015	0.405	Quarter	Regular Cash
1/28/2015	2/11/2015	2/13/2015	3/1/2015	0.405	Quarter	Regular Cash
10/28/2014	11/13/2014	11/17/2014	12/1/2014	0.39	Quarter	Regular Cash
7/30/2014	8/13/2014	8/15/2014	9/1/2014	0.39	Quarter	Regular Cash
4/28/2014	5/14/2014	5/16/2014	6/1/2014	0.39	Quarter	Regular Cash
1/30/2014	2/12/2014	2/14/2014	3/1/2014	0.39	Quarter	Regular Cash
10/29/2013	11/13/2013	11/15/2013	12/1/2013	0.38	Quarter	Regular Cash
7/25/2013	8/14/2013	8/16/2013	9/1/2013	0.38	Quarter	Regular Cash
4/23/2013	5/15/2013	5/17/2013	6/1/2013	0.38	Quarter	Regular Cash
1/31/2013	2/13/2013	2/15/2013	3/1/2013	0.38	Quarter	Regular Cash
10/31/2012	11/14/2012	11/16/2012	12/1/2012	0.37	Quarter	Regular Cash
7/26/2012	8/15/2012	8/17/2012	9/1/2012	0.37	Quarter	Regular Cash
4/26/2012	5/16/2012	5/18/2012	6/1/2012	0.37	Quarter	Regular Cash
1/26/2012	2/14/2012	2/16/2012	3/1/2012	0.37	Quarter	Regular Cash
10/27/2011	11/15/2011	11/17/2011	12/1/2011	0.365	Quarter	Regular Cash
7/28/2011	8/16/2011	8/18/2011	9/1/2011	0.365	Quarter	Regular Cash
4/28/2011	5/16/2011	5/18/2011	6/1/2011	0.365	Quarter	Regular Cash
1/27/2011	2/11/2011	2/15/2011	3/1/2011	0.365	Quarter	Regular Cash
10/28/2010	11/15/2010	11/17/2010	12/1/2010	0.36	Quarter	Regular Cash
7/29/2010	8/16/2010	8/18/2010	9/1/2010	0.36	Quarter	Regular Cash
4/30/2010	5/14/2010	5/18/2010	6/1/2010	0.36	Quarter	Regular Cash
1/28/2010	2/10/2010	2/12/2010	3/1/2010	0.36	Quarter	Regular Cash
10/29/2009	11/13/2009	11/17/2009	12/1/2009	0.355	Quarter	Regular Cash
7/29/2009	8/14/2009	8/18/2009	9/1/2009	0.355	Quarter	Regular Cash
4/28/2009	5/14/2009	5/18/2009	6/1/2009	0.355	Quarter	Regular Cash
1/30/2009	2/11/2009	2/13/2009	3/1/2009	0.355	Quarter	Regular Cash
10/31/2008	11/12/2008	11/14/2008	12/1/2008	0.35	Quarter	Regular Cash
8/4/2008	8/13/2008	8/15/2008	9/1/2008	0.35	Quarter	Regular Cash
4/28/2008	5/14/2008	5/16/2008	6/1/2008	0.35	Quarter	Regular Cash
1/31/2008	2/13/2008	2/15/2008	3/1/2008	0.35	Quarter	Regular Cash
11/1/2007	11/14/2007	11/16/2007	12/1/2007	0.35	Quarter	Regular Cash
7/25/2007	8/15/2007	8/17/2007	9/1/2007	0.34	Quarter	Regular Cash
4/27/2007	5/16/2007	5/18/2007	6/1/2007	0.34	Quarter	Regular Cash
2/5/2007	2/13/2007	2/15/2007	3/1/2007	0.34	Quarter	Regular Cash
10/27/2006	11/15/2006	11/17/2006	12/1/2006	0.33	Quarter	Regular Cash
7/27/2006	8/16/2006	8/18/2006	9/1/2006	0.33	Quarter	Regular Cash
4/27/2006	5/16/2006	5/18/2006	6/1/2006	0.33	Quarter	Regular Cash
2/2/2006	2/13/2006	2/15/2006	3/1/2006	0.33	Quarter	Regular Cash
11/7/2005	11/15/2005	11/17/2005	12/1/2005	0.32	Quarter	Regular Cash
8/1/2005	8/16/2005	8/18/2005	9/1/2005	0.32	Quarter	Regular Cash
4/28/2005	5/16/2005	5/18/2005	6/1/2005	0.32	Quarter	Regular Cash
2/4/2005	2/11/2005	2/15/2005	3/1/2005	0.32	Quarter	Regular Cash

11/5/2004	11/15/2004	11/17/2004	12/1/2004	0.31	Quarter	Regular Cash
7/30/2004	8/12/2004	8/16/2004	9/1/2004	0.31	Quarter	Regular Cash
5/3/2004	5/13/2004	5/17/2004	6/1/2004	0.31	Quarter	Regular Cash
2/5/2004	2/12/2004	2/17/2004	3/1/2004	0.31	Quarter	Regular Cash
10/30/2003	11/12/2003	11/14/2003	12/1/2003	0.3	Quarter	Regular Cash
8/4/2003	8/13/2003	8/15/2003	9/1/2003	0.3	Quarter	Regular Cash
5/6/2003	5/16/2003	5/20/2003	6/1/2003	0.3	Quarter	Regular Cash
2/3/2003	2/12/2003	2/14/2003	3/1/2003	0.3	Quarter	Regular Cash
10/29/2002	11/13/2002	11/15/2002	12/1/2002	0.29	Quarter	Regular Cash
7/29/2002	8/14/2002	8/16/2002	9/1/2002	0.29	Quarter	Regular Cash
4/23/2002	5/15/2002	5/17/2002	6/1/2002	0.29	Quarter	Regular Cash
1/30/2002	2/13/2002	2/15/2002	3/1/2002	0.29	Quarter	Regular Cash
11/6/2001	11/15/2001	11/19/2001	12/1/2001	0.28	Quarter	Regular Cash
7/31/2001	8/14/2001	8/16/2001	9/1/2001	0.28	Quarter	Regular Cash
5/3/2001	5/16/2001	5/18/2001	6/1/2001	0.28	Quarter	Regular Cash
1/31/2001	2/14/2001	2/16/2001	3/1/2001	0.28	Quarter	Regular Cash
10/24/2000	11/15/2000	11/17/2000	12/1/2000	0.27	Quarter	Regular Cash
7/25/2000	8/16/2000	8/18/2000	9/1/2000	0.27	Quarter	Regular Cash
4/27/2000	5/10/2000	5/12/2000	6/1/2000	0.27	Quarter	Regular Cash
2/4/2000	2/9/2000	2/11/2000	3/1/2000	0.27	Quarter	Regular Cash
10/26/1999	11/9/1999	11/12/1999	12/1/1999	0.26	Quarter	Regular Cash
8/4/1999	8/11/1999	8/13/1999	9/1/1999	0.26	Quarter	Regular Cash
4/23/1999	5/12/1999	5/14/1999	6/1/1999	0.26	Quarter	Regular Cash
1/28/1999	2/10/1999	2/12/1999	3/1/1999	0.26	Quarter	Regular Cash
10/27/1998	11/10/1998	11/13/1998	12/1/1998	0.25	Quarter	Regular Cash
7/20/1998	8/12/1998	8/14/1998	9/1/1998	0.25	Quarter	Regular Cash
4/22/1998	5/13/1998	5/15/1998	6/1/1998	0.25	Quarter	Regular Cash
1/29/1998	2/11/1998	2/13/1998	3/1/1998	0.25	Quarter	Regular Cash
10/20/1997	11/12/1997	11/14/1997	12/1/1997	0.236667	Quarter	Regular Cash
7/23/1997	8/13/1997	8/15/1997	9/1/1997	0.236667	Quarter	Regular Cash
4/22/1997	5/14/1997	5/16/1997	6/1/1997	0.236667	Quarter	Regular Cash
1/31/1997	2/12/1997	2/14/1997	3/1/1997	0.236667	Quarter	Regular Cash
10/24/1996	11/13/1996	11/15/1996	12/1/1996	0.23	Quarter	Regular Cash
7/29/1996	8/14/1996	8/16/1996	9/1/1996	0.23	Quarter	Regular Cash
4/25/1996	5/15/1996	5/17/1996	6/1/1996	0.23	Quarter	Regular Cash
1/31/1996	2/14/1996	2/16/1996	3/1/1996	0.23	Quarter	Regular Cash
10/25/1995	11/8/1995	11/10/1995	12/1/1995	0.223333	Quarter	Regular Cash
7/25/1995	8/9/1995	8/11/1995	9/1/1995	0.223333	Quarter	Regular Cash
4/27/1995	5/8/1995	5/12/1995	6/1/1995	0.223333	Quarter	Regular Cash
1/30/1995	2/6/1995	2/10/1995	3/1/1995	0.223333	Quarter	Regular Cash
10/25/1994	11/4/1994	11/10/1994	12/1/1994	0.22	Quarter	Regular Cash
7/21/1994	8/8/1994	8/12/1994	9/1/1994	0.22	Quarter	Regular Cash
4/28/1994	5/9/1994	5/13/1994	6/1/1994	0.22	Quarter	Regular Cash
1/31/1994	2/7/1994	2/11/1994	3/1/1994	0.22	Quarter	Regular Cash
10/27/1993	11/5/1993	11/12/1993	12/1/1993	0.213333	Quarter	Regular Cash
8/2/1993	8/9/1993	8/13/1993	9/1/1993	0.213333	Quarter	Regular Cash
4/27/1993	5/10/1993	5/14/1993	6/1/1993	0.213333	Quarter	Regular Cash
1/26/1993	2/8/1993	2/12/1993	3/1/1993	0.213333	Quarter	Regular Cash
10/22/1992	11/6/1992	11/13/1992	12/1/1992	0.206667	Quarter	Regular Cash
7/27/1992	8/10/1992	8/14/1992	9/1/1992	0.206667	Quarter	Regular Cash
4/22/1992	5/11/1992	5/15/1992	6/1/1992	0.206667	Quarter	Regular Cash
1/31/1992	2/4/1992	2/10/1992	3/1/1992	0.206667	Quarter	Regular Cash
10/22/1991	11/4/1991	11/8/1991	12/1/1991	0.195556	Quarter	Regular Cash
8/5/1991	8/12/1991	8/16/1991	9/1/1991	0.195556	Quarter	Regular Cash
4/25/1991	5/6/1991	5/10/1991	6/1/1991	0.195556	Quarter	Regular Cash
1/29/1991	2/4/1991	2/8/1991	3/1/1991	0.195556	Quarter	Regular Cash
10/24/1990	11/5/1990	11/9/1990	12/1/1990	0.182222	Quarter	Regular Cash
7/26/1990	8/6/1990	8/10/1990	9/1/1990	0.182222	Quarter	Regular Cash
4/25/1990	5/7/1990	5/11/1990	6/1/1990	0.182222	Quarter	Regular Cash
1/24/1990	2/5/1990	2/9/1990	3/1/1990	0.182222	Quarter	Regular Cash
10/26/1989	11/13/1989	11/17/1989	12/1/1989	0.168889	Quarter	Regular Cash
7/28/1989	8/14/1989	8/18/1989	9/1/1989	0.168889	Quarter	Regular Cash
4/19/1989	5/8/1989	5/12/1989	6/1/1989	0.168889	Quarter	Regular Cash
1/25/1989	2/6/1989	2/10/1989	3/1/1989	0.168889	Quarter	Regular Cash
10/26/1988	11/4/1988	11/11/1988	12/1/1988	0.155556	Quarter	Regular Cash
7/26/1988	8/8/1988	8/12/1988	9/1/1988	0.155556	Quarter	Regular Cash

4/20/1988	5/9/1988	5/13/1988	6/1/1988	0.155556	Quarter	Regular Cash
1/27/1988	2/8/1988	2/12/1988	3/1/1988	0.155556	Quarter	Regular Cash
10/28/1987	11/6/1987	11/13/1987	12/1/1987	0.142222	Quarter	Regular Cash
7/29/1987	8/10/1987	8/14/1987	9/1/1987	0.142222	Quarter	Regular Cash
4/21/1987	5/11/1987	5/15/1987	6/1/1987	0.133333	Quarter	Regular Cash
1/29/1987	2/9/1987	2/13/1987	3/1/1987	0.133333	Quarter	Regular Cash
10/28/1986	11/7/1986	11/14/1986	12/1/1986	0.126667	Quarter	Regular Cash
7/30/1986	8/11/1986	8/15/1986	9/1/1986	0.126667	Quarter	Regular Cash
4/23/1986	5/12/1986	5/16/1986	6/1/1986	0.126667	Quarter	Regular Cash
1/13/1986	2/3/1986	2/7/1986	3/1/1986	0.126667	Quarter	Regular Cash
11/1/1984	11/9/1984	11/16/1984	12/1/1984	0.093333	Quarter	Regular Cash
7/27/1984	8/13/1984	8/17/1984	9/1/1984	0.093333	Quarter	Regular Cash
4/26/1984	5/7/1984	5/11/1984	6/1/1984	0.093333	Quarter	Regular Cash
1/26/1984	2/6/1984	2/10/1984	3/1/1984	0.093333	Quarter	Regular Cash
10/27/1983	11/3/1983	11/10/1983	12/1/1983	0.075556	Quarter	Regular Cash
7/28/1983	8/8/1983	8/12/1983	9/1/1983	0.075556	Quarter	Regular Cash
5/10/1983	5/16/1983	5/20/1983	6/1/1983	0.075556	Quarter	Regular Cash
1/26/1983	2/7/1983	2/11/1983	3/1/1983	0.066667	Quarter	Regular Cash
10/28/1982	11/5/1982	11/12/1982	12/1/1982	0.066667	Quarter	Regular Cash
7/29/1982	8/9/1982	8/13/1982	9/1/1982	0.066667	Quarter	Regular Cash
4/26/1982	5/10/1982	5/14/1982	6/1/1982	0.066667	Quarter	Regular Cash
1/29/1982	2/5/1982	2/11/1982	3/1/1982	0.06	Quarter	Regular Cash
10/29/1981	11/6/1981	11/13/1981	12/1/1981	0.06	Quarter	Regular Cash
7/30/1981	8/10/1981	8/14/1981	9/1/1981	0.06	Quarter	Regular Cash
5/4/1981	5/11/1981	5/15/1981	6/1/1981	0.06	Quarter	Regular Cash
2/3/1981	2/6/1981	2/13/1981	3/1/1981	0.054444	Quarter	Regular Cash
10/31/1980	11/7/1980	11/14/1980	12/1/1980	0.054444	Quarter	Regular Cash
7/24/1980	8/11/1980	8/15/1980	9/1/1980	0.054444	Quarter	Regular Cash
4/28/1980	5/12/1980	5/16/1980	5/30/1980	0.054444	Quarter	Regular Cash
1/30/1980	2/8/1980	2/15/1980	2/29/1980	0.05	Quarter	Regular Cash

EE US Equity
DVD_HIST

2/1/2018	3/15/2018	3/16/2018	3/30/2018	0.34	Quarter	Regular Cash
10/26/2017	12/14/2017	12/15/2017	12/29/2017	0.34	Quarter	Regular Cash
7/27/2017	9/14/2017	9/15/2017	9/29/2017	0.34	Quarter	Regular Cash
5/25/2017	6/14/2017	6/16/2017	6/30/2017	0.34	Quarter	Regular Cash
1/26/2017	3/15/2017	3/17/2017	3/31/2017	0.31	Quarter	Regular Cash
11/17/2016	12/12/2016	12/14/2016	12/30/2016	0.31	Quarter	Regular Cash
7/21/2016	9/12/2016	9/14/2016	9/30/2016	0.31	Quarter	Regular Cash
5/26/2016	6/13/2016	6/15/2016	6/30/2016	0.31	Quarter	Regular Cash
1/28/2016	3/11/2016	3/15/2016	3/31/2016	0.3	Quarter	Regular Cash
12/4/2015	12/11/2015	12/15/2015	12/30/2015	0.3	Quarter	Regular Cash
7/23/2015	9/14/2015	9/16/2015	9/30/2015	0.3	Quarter	Regular Cash
5/28/2015	6/12/2015	6/16/2015	6/30/2015	0.3	Quarter	Regular Cash
1/29/2015	3/12/2015	3/16/2015	3/31/2015	0.28	Quarter	Regular Cash
11/20/2014	12/10/2014	12/12/2014	12/30/2014	0.28	Quarter	Regular Cash
7/31/2014	9/11/2014	9/15/2014	9/30/2014	0.28	Quarter	Regular Cash
5/29/2014	6/11/2014	6/13/2014	6/30/2014	0.28	Quarter	Regular Cash
1/23/2014	3/12/2014	3/14/2014	3/31/2014	0.27	Quarter	Regular Cash
11/21/2013	12/11/2013	12/13/2013	12/30/2013	0.27	Quarter	Regular Cash
8/6/2013	9/11/2013	9/13/2013	9/30/2013	0.27	Quarter	Regular Cash
5/9/2013	6/11/2013	6/13/2013	6/28/2013	0.27	Quarter	Regular Cash
1/17/2013	3/12/2013	3/14/2013	3/29/2013	0.25	Quarter	Regular Cash
10/24/2012	12/11/2012	12/13/2012	12/28/2012	0.25	Quarter	Regular Cash
7/25/2012	9/12/2012	9/14/2012	9/28/2012	0.25	Quarter	Regular Cash
5/31/2012	6/13/2012	6/15/2012	6/29/2012	0.25	Quarter	Regular Cash
1/31/2012	3/13/2012	3/15/2012	3/30/2012	0.22	Quarter	Regular Cash
11/17/2011	12/13/2011	12/15/2011	12/30/2011	0.22	Quarter	Regular Cash
7/28/2011	9/13/2011	9/15/2011	9/30/2011	0.22	Quarter	Regular Cash
4/28/2011	6/13/2011	6/15/2011	6/30/2011	0.22	Quarter	Regular Cash
3/10/1992	4/1/1992	4/7/1992	4/14/1992	0.99	Annual	Regular Cash
3/5/1991	4/1/1991	4/5/1991	4/12/1991	0.99	Annual	Regular Cash
3/2/1990	3/27/1990	4/2/1990	4/10/1990	0.81	Annual	Regular Cash
3/2/1989	3/28/1989	4/3/1989	4/11/1989	0.9	Annual	Regular Cash
3/14/1988	4/4/1988	4/8/1988	4/15/1988	0.27	None	Special Cash
3/14/1988	4/4/1988	4/8/1988	4/15/1988	0.72	Annual	Regular Cash
2/26/1987	3/23/1987	3/27/1987	4/10/1987	0.72	None	Special Cash
2/25/1986	3/21/1986	3/28/1986	4/11/1986	0.72	Annual	Regular Cash
2/21/1985	3/25/1985	3/29/1985	4/12/1985	0.72	None	Special Cash

HE US Equity
DVD_HIST

5/10/2018	5/22/2018	5/23/2018	6/12/2018	0.31	Quarter	Regular Cash
2/2/2018	2/21/2018	2/22/2018	3/13/2018	0.31	Quarter	Regular Cash
11/1/2017	11/21/2017	11/22/2017	12/12/2017	0.31	Quarter	Regular Cash
8/2/2017	8/21/2017	8/23/2017	9/12/2017	0.31	Quarter	Regular Cash
5/4/2017	5/22/2017	5/24/2017	6/12/2017	0.31	Quarter	Regular Cash
2/14/2017	2/22/2017	2/24/2017	3/10/2017	0.31	Quarter	Regular Cash
11/2/2016	11/18/2016	11/22/2016	12/13/2016	0.31	Quarter	Regular Cash
8/3/2016	8/22/2016	8/24/2016	9/12/2016	0.31	Quarter	Regular Cash
5/4/2016	5/26/2016	5/31/2016	6/15/2016	0.31	Quarter	Regular Cash
2/9/2016	2/18/2016	2/22/2016	3/10/2016	0.31	Quarter	Regular Cash
11/5/2015	11/19/2015	11/23/2015	12/10/2015	0.31	Quarter	Regular Cash
8/10/2015	8/20/2015	8/24/2015	9/10/2015	0.31	Quarter	Regular Cash
5/6/2015	5/20/2015	5/22/2015	6/10/2015	0.31	Quarter	Regular Cash
2/10/2015	2/20/2015	2/24/2015	3/10/2015	0.31	Quarter	Regular Cash
11/5/2014	11/19/2014	11/21/2014	12/10/2014	0.31	Quarter	Regular Cash
8/7/2014	8/20/2014	8/22/2014	9/10/2014	0.31	Quarter	Regular Cash
5/6/2014	5/20/2014	5/22/2014	6/10/2014	0.31	Quarter	Regular Cash
2/11/2014	2/21/2014	2/25/2014	3/12/2014	0.31	Quarter	Regular Cash
11/7/2013	11/18/2013	11/20/2013	12/11/2013	0.31	Quarter	Regular Cash
8/6/2013	8/19/2013	8/21/2013	9/11/2013	0.31	Quarter	Regular Cash
5/7/2013	5/20/2013	5/22/2013	6/12/2013	0.31	Quarter	Regular Cash
2/6/2013	2/19/2013	2/21/2013	3/13/2013	0.31	Quarter	Regular Cash
11/7/2012	11/15/2012	11/19/2012	12/12/2012	0.31	Quarter	Regular Cash
8/2/2012	8/13/2012	8/15/2012	9/12/2012	0.31	Quarter	Regular Cash
5/8/2012	5/17/2012	5/21/2012	6/13/2012	0.31	Quarter	Regular Cash
2/8/2012	2/16/2012	2/21/2012	3/13/2012	0.31	Quarter	Regular Cash
11/3/2011	11/17/2011	11/21/2011	12/13/2011	0.31	Quarter	Regular Cash
8/3/2011	8/11/2011	8/15/2011	9/13/2011	0.31	Quarter	Regular Cash
5/9/2011	5/18/2011	5/20/2011	6/14/2011	0.31	Quarter	Regular Cash
2/11/2011	2/17/2011	2/22/2011	3/10/2011	0.31	Quarter	Regular Cash
10/29/2010	11/10/2010	11/15/2010	12/10/2010	0.31	Quarter	Regular Cash
8/9/2010	8/19/2010	8/23/2010	9/10/2010	0.31	Quarter	Regular Cash
5/10/2010	5/19/2010	5/21/2010	6/10/2010	0.31	Quarter	Regular Cash
2/12/2010	2/18/2010	2/22/2010	3/10/2010	0.31	Quarter	Regular Cash
11/2/2009	11/12/2009	11/16/2009	12/10/2009	0.31	Quarter	Regular Cash
8/7/2009	8/20/2009	8/24/2009	9/10/2009	0.31	Quarter	Regular Cash
5/5/2009	5/19/2009	5/21/2009	6/10/2009	0.31	Quarter	Regular Cash
2/19/2009	2/26/2009	3/2/2009	3/10/2009	0.31	Quarter	Regular Cash
11/4/2008	11/13/2008	11/17/2008	12/10/2008	0.31	Quarter	Regular Cash
8/4/2008	8/14/2008	8/18/2008	9/10/2008	0.31	Quarter	Regular Cash
5/6/2008	5/14/2008	5/16/2008	6/10/2008	0.31	Quarter	Regular Cash
2/21/2008	2/28/2008	3/3/2008	3/11/2008	0.31	Quarter	Regular Cash
11/2/2007	11/13/2007	11/15/2007	12/11/2007	0.31	Quarter	Regular Cash
8/7/2007	8/16/2007	8/20/2007	9/11/2007	0.31	Quarter	Regular Cash
5/4/2007	5/11/2007	5/15/2007	6/13/2007	0.31	Quarter	Regular Cash
2/15/2007	2/22/2007	2/26/2007	3/13/2007	0.31	Quarter	Regular Cash
11/1/2006	11/13/2006	11/15/2006	12/12/2006	0.31	Quarter	Regular Cash
8/1/2006	8/11/2006	8/15/2006	9/12/2006	0.31	Quarter	Regular Cash
5/2/2006	5/11/2006	5/15/2006	6/14/2006	0.31	Quarter	Regular Cash
2/1/2006	2/21/2006	2/23/2006	3/10/2006	0.31	Quarter	Regular Cash
11/10/2005	11/17/2005	11/21/2005	12/12/2005	0.31	Quarter	Regular Cash
7/26/2005	8/8/2005	8/10/2005	9/12/2005	0.31	Quarter	Regular Cash
4/26/2005	5/6/2005	5/10/2005	6/13/2005	0.31	Quarter	Regular Cash
1/25/2005	2/14/2005	2/16/2005	3/10/2005	0.31	Quarter	Regular Cash

10/26/2004	11/8/2004	11/10/2004	12/10/2004	0.31	Quarter	Regular Cash
7/20/2004	8/6/2004	8/10/2004	9/10/2004	0.31	Quarter	Regular Cash
4/20/2004	5/6/2004	5/10/2004	6/10/2004	0.31	Quarter	Regular Cash
1/20/2004	2/9/2004	2/11/2004	3/10/2004	0.31	Quarter	Regular Cash
10/28/2003	11/6/2003	11/10/2003	12/10/2003	0.31	Quarter	Regular Cash
7/22/2003	8/7/2003	8/11/2003	9/10/2003	0.31	Quarter	Regular Cash
4/22/2003	5/8/2003	5/12/2003	6/10/2003	0.31	Quarter	Regular Cash
1/21/2003	2/10/2003	2/12/2003	3/10/2003	0.31	Quarter	Regular Cash
10/23/2002	11/7/2002	11/12/2002	12/10/2002	0.31	Quarter	Regular Cash
7/23/2002	8/8/2002	8/12/2002	9/10/2002	0.31	Quarter	Regular Cash
4/24/2002	5/8/2002	5/10/2002	6/10/2002	0.31	Quarter	Regular Cash
1/23/2002	2/11/2002	2/13/2002	3/11/2002	0.31	Quarter	Regular Cash
10/24/2001	11/8/2001	11/13/2001	12/10/2001	0.31	Quarter	Regular Cash
7/24/2001	8/8/2001	8/10/2001	9/10/2001	0.31	Quarter	Regular Cash
4/24/2001	5/8/2001	5/10/2001	6/12/2001	0.31	Quarter	Regular Cash
1/23/2001	2/12/2001	2/14/2001	3/12/2001	0.31	Quarter	Regular Cash
10/25/2000	11/9/2000	11/13/2000	12/11/2000	0.31	Quarter	Regular Cash
7/25/2000	8/8/2000	8/10/2000	9/11/2000	0.31	Quarter	Regular Cash
4/25/2000	5/8/2000	5/10/2000	6/13/2000	0.31	Quarter	Regular Cash
1/25/2000	2/14/2000	2/16/2000	3/10/2000	0.31	Quarter	Regular Cash
10/19/1999	11/8/1999	11/10/1999	12/10/1999	0.31	Quarter	Regular Cash
7/20/1999	8/6/1999	8/10/1999	9/10/1999	0.31	Quarter	Regular Cash
4/27/1999	5/6/1999	5/10/1999	6/10/1999	0.31	Quarter	Regular Cash
1/19/1999	2/12/1999	2/17/1999	3/10/1999	0.31	Quarter	Regular Cash
10/20/1998	11/6/1998	11/10/1998	12/10/1998	0.31	Quarter	Regular Cash
7/21/1998	8/6/1998	8/10/1998	9/10/1998	0.31	Quarter	Regular Cash
4/28/1998	5/7/1998	5/11/1998	6/10/1998	0.31	Quarter	Regular Cash
1/21/1998	2/13/1998	2/18/1998	3/10/1998	0.31	Quarter	Regular Cash
10/29/1997	11/6/1997	11/10/1997	12/10/1997	0.305	Quarter	Regular Cash
7/14/1997	8/7/1997	8/11/1997	9/10/1997	0.305	Quarter	Regular Cash
4/22/1997	5/8/1997	5/12/1997	6/10/1997	0.305	Quarter	Regular Cash
1/21/1997	2/10/1997	2/12/1997	3/10/1997	0.305	Quarter	Regular Cash
10/15/1996	11/7/1996	11/12/1996	12/10/1996	0.305	Quarter	Regular Cash
7/16/1996	8/8/1996	8/12/1996	9/10/1996	0.3	Quarter	Regular Cash
4/23/1996	5/8/1996	5/10/1996	6/10/1996	0.3	Quarter	Regular Cash
1/16/1996	2/12/1996	2/14/1996	3/11/1996	0.3	Quarter	Regular Cash
10/17/1995	11/9/1995	11/13/1995	12/11/1995	0.3	Quarter	Regular Cash
7/19/1995	8/8/1995	8/10/1995	9/11/1995	0.295	Quarter	Regular Cash
4/25/1995	5/4/1995	5/10/1995	6/13/1995	0.295	Quarter	Regular Cash
1/18/1995	2/9/1995	2/15/1995	3/10/1995	0.295	Quarter	Regular Cash
10/18/1994	11/4/1994	11/10/1994	12/12/1994	0.295	Quarter	Regular Cash
7/19/1994	8/4/1994	8/10/1994	9/12/1994	0.29	Quarter	Regular Cash
4/19/1994	5/4/1994	5/10/1994	6/13/1994	0.29	Quarter	Regular Cash
1/18/1994	2/4/1994	2/10/1994	3/10/1994	0.29	Quarter	Regular Cash
10/19/1993	11/4/1993	11/10/1993	12/10/1993	0.29	Quarter	Regular Cash
7/20/1993	8/4/1993	8/10/1993	9/10/1993	0.285	Quarter	Regular Cash
4/20/1993	5/4/1993	5/10/1993	6/10/1993	0.285	Quarter	Regular Cash
1/20/1993	2/4/1993	2/10/1993	3/10/1993	0.285	Quarter	Regular Cash
10/20/1992	11/4/1992	11/10/1992	12/10/1992	0.285	Quarter	Regular Cash
7/21/1992	8/4/1992	8/10/1992	9/10/1992	0.28	Quarter	Regular Cash
4/22/1992	5/5/1992	5/11/1992	6/10/1992	0.28	Quarter	Regular Cash
1/21/1992	2/6/1992	2/12/1992	3/10/1992	0.28	Quarter	Regular Cash
10/16/1991	11/5/1991	11/12/1991	12/10/1991	0.28	Quarter	Regular Cash
7/17/1991	8/6/1991	8/12/1991	9/10/1991	0.275	Quarter	Regular Cash
4/17/1991	5/6/1991	5/10/1991	6/10/1991	0.275	Quarter	Regular Cash
1/17/1991	2/5/1991	2/11/1991	3/11/1991	0.275	Quarter	Regular Cash
10/17/1990	11/6/1990	11/13/1990	12/10/1990	0.275	Quarter	Regular Cash
7/17/1990	8/6/1990	8/10/1990	9/10/1990	0.27	Quarter	Regular Cash
4/18/1990	5/4/1990	5/10/1990	6/12/1990	0.27	Quarter	Regular Cash
1/17/1990	2/6/1990	2/12/1990	3/12/1990	0.27	Quarter	Regular Cash
10/17/1989	11/7/1989	11/13/1989	12/8/1989	0.27	Quarter	Regular Cash
7/19/1989	8/7/1989	8/11/1989	9/8/1989	0.255	Quarter	Regular Cash
4/19/1989	5/8/1989	5/12/1989	6/9/1989	0.255	Quarter	Regular Cash
1/18/1989	2/6/1989	2/10/1989	3/10/1989	0.255	Quarter	Regular Cash
10/19/1988	10/31/1988	11/4/1988	12/9/1988	0.255	Quarter	Regular Cash
7/20/1988	8/1/1988	8/5/1988	9/9/1988	0.24	Quarter	Regular Cash

4/19/1988	5/2/1988	5/6/1988	6/10/1988	0.24	Quarter	Regular Cash
1/20/1988	2/1/1988	2/5/1988	3/10/1988	0.24	Quarter	Regular Cash
10/20/1987	11/4/1987	11/10/1987	12/10/1987	0.24	Quarter	Regular Cash
7/24/1987	8/4/1987	8/10/1987	9/10/1987	0.225	Quarter	Regular Cash
4/23/1987	5/4/1987	5/8/1987	6/10/1987	0.225	Quarter	Regular Cash
1/20/1987	2/2/1987	2/6/1987	3/10/1987	0.225	Quarter	Regular Cash
10/21/1986	11/4/1986	11/10/1986	12/10/1986	0.225	Quarter	Regular Cash
7/15/1986	8/4/1986	8/8/1986	9/10/1986	0.215	Quarter	Regular Cash
4/15/1986	5/5/1986	5/9/1986	6/10/1986	0.215	Quarter	Regular Cash
1/23/1986	2/3/1986	2/7/1986	3/10/1986	0.215	Quarter	Regular Cash
10/16/1985	11/5/1985	11/12/1985	12/10/1985	0.215	Quarter	Regular Cash
7/17/1985	8/5/1985	8/9/1985	9/10/1985	0.205	Quarter	Regular Cash
4/17/1985	5/6/1985	5/10/1985	6/10/1985	0.205	Quarter	Regular Cash
1/15/1985	2/5/1985	2/11/1985	3/11/1985	0.205	Quarter	Regular Cash
10/18/1984	11/2/1984	11/9/1984	12/10/1984	0.205	Quarter	Regular Cash
7/24/1984	8/6/1984	8/10/1984	9/10/1984	0.195	Quarter	Regular Cash
4/23/1984	5/4/1984	5/10/1984	6/11/1984	0.195	Quarter	Regular Cash
1/20/1984	2/10/1984	2/17/1984	3/12/1984	0.195	Quarter	Regular Cash
10/21/1982	11/4/1982	11/10/1982	12/10/1982	0.1875	Quarter	Regular Cash
7/26/1982	8/4/1982	8/10/1982	9/10/1982	0.1775	Quarter	Regular Cash
4/23/1982	5/4/1982	5/10/1982	6/10/1982	0.1775	Quarter	Regular Cash
1/21/1982	2/4/1982	2/10/1982	3/10/1982	0.1775	Quarter	Regular Cash
9/17/1981	11/4/1981	11/10/1981	12/10/1981	0.1775	Quarter	Regular Cash
7/27/1981	8/4/1981	8/10/1981	9/10/1981	0.165	Quarter	Regular Cash
4/23/1981	5/5/1981	5/11/1981	6/10/1981	0.165	Quarter	Regular Cash
1/22/1981	2/2/1981	2/6/1981	3/10/1981	0.165	Quarter	Regular Cash
9/18/1980	11/3/1980	11/10/1980	12/10/1980	0.165	Quarter	Regular Cash
7/18/1980	8/4/1980	8/8/1980	9/10/1980	0.1525	Quarter	Regular Cash
4/17/1980	5/5/1980	5/9/1980	6/10/1980	0.1525	Quarter	Regular Cash
1/17/1980	2/4/1980	2/8/1980	3/10/1980	0.1525	Quarter	Regular Cash

IDA

IDA US Equity
DVD_HIST

4/19/2018	5/4/2018	5/7/2018	5/30/2018	0.59	Quarter	Regular Cash
1/18/2018	2/2/2018	2/5/2018	2/28/2018	0.59	Quarter	Regular Cash
9/22/2017	11/3/2017	11/6/2017	11/30/2017	0.59	Quarter	Regular Cash
7/20/2017	8/4/2017	8/8/2017	8/30/2017	0.55	Quarter	Regular Cash
4/20/2017	5/3/2017	5/5/2017	5/30/2017	0.55	Quarter	Regular Cash
1/19/2017	2/2/2017	2/6/2017	2/28/2017	0.55	Quarter	Regular Cash
9/13/2016	11/3/2016	11/7/2016	11/30/2016	0.55	Quarter	Regular Cash
7/21/2016	8/3/2016	8/5/2016	8/30/2016	0.51	Quarter	Regular Cash
4/21/2016	5/3/2016	5/5/2016	5/31/2016	0.51	Quarter	Regular Cash
1/21/2016	2/3/2016	2/5/2016	2/29/2016	0.51	Quarter	Regular Cash
9/17/2015	11/3/2015	11/5/2015	11/30/2015	0.51	Quarter	Regular Cash
7/16/2015	8/3/2015	8/5/2015	8/31/2015	0.47	Quarter	Regular Cash
4/16/2015	5/1/2015	5/5/2015	6/1/2015	0.47	Quarter	Regular Cash
1/15/2015	2/3/2015	2/5/2015	3/2/2015	0.47	Quarter	Regular Cash
9/18/2014	11/3/2014	11/5/2014	12/1/2014	0.47	Quarter	Regular Cash
7/17/2014	8/1/2014	8/5/2014	9/2/2014	0.43	Quarter	Regular Cash
4/17/2014	5/2/2014	5/6/2014	5/30/2014	0.43	Quarter	Regular Cash
1/16/2014	2/3/2014	2/5/2014	2/28/2014	0.43	Quarter	Regular Cash
9/19/2013	11/4/2013	11/6/2013	12/2/2013	0.43	Quarter	Regular Cash
7/18/2013	8/2/2013	8/6/2013	8/30/2013	0.38	Quarter	Regular Cash
4/18/2013	5/3/2013	5/7/2013	5/30/2013	0.38	Quarter	Regular Cash
1/17/2013	2/4/2013	2/6/2013	2/28/2013	0.38	Quarter	Regular Cash
9/20/2012	11/1/2012	11/5/2012	11/30/2012	0.38	Quarter	Regular Cash
7/19/2012	8/2/2012	8/6/2012	8/30/2012	0.33	Quarter	Regular Cash
4/19/2012	5/3/2012	5/7/2012	5/30/2012	0.33	Quarter	Regular Cash
1/19/2012	2/2/2012	2/6/2012	2/29/2012	0.33	Quarter	Regular Cash
10/20/2011	11/3/2011	11/7/2011	11/30/2011	0.3	Quarter	Regular Cash
7/21/2011	8/3/2011	8/5/2011	8/30/2011	0.3	Quarter	Regular Cash
4/21/2011	5/3/2011	5/5/2011	5/31/2011	0.3	Quarter	Regular Cash
1/20/2011	2/3/2011	2/7/2011	2/28/2011	0.3	Quarter	Regular Cash
10/21/2010	11/3/2010	11/5/2010	11/30/2010	0.3	Quarter	Regular Cash
7/15/2010	8/3/2010	8/5/2010	8/30/2010	0.3	Quarter	Regular Cash
4/15/2010	5/3/2010	5/5/2010	6/1/2010	0.3	Quarter	Regular Cash
1/21/2010	2/3/2010	2/5/2010	3/1/2010	0.3	Quarter	Regular Cash
10/15/2009	11/3/2009	11/5/2009	11/30/2009	0.3	Quarter	Regular Cash
7/16/2009	8/3/2009	8/5/2009	8/31/2009	0.3	Quarter	Regular Cash
4/16/2009	5/1/2009	5/5/2009	6/1/2009	0.3	Quarter	Regular Cash
1/22/2009	2/3/2009	2/5/2009	3/2/2009	0.3	Quarter	Regular Cash
10/16/2008	11/3/2008	11/5/2008	12/1/2008	0.3	Quarter	Regular Cash
7/17/2008	8/1/2008	8/5/2008	9/2/2008	0.3	Quarter	Regular Cash
4/17/2008	5/1/2008	5/5/2008	5/30/2008	0.3	Quarter	Regular Cash
1/17/2008	2/1/2008	2/5/2008	2/29/2008	0.3	Quarter	Regular Cash
10/18/2007	11/1/2007	11/5/2007	11/30/2007	0.3	Quarter	Regular Cash
7/19/2007	8/2/2007	8/6/2007	8/30/2007	0.3	Quarter	Regular Cash
4/19/2007	5/3/2007	5/7/2007	5/30/2007	0.3	Quarter	Regular Cash
1/18/2007	2/1/2007	2/5/2007	2/28/2007	0.3	Quarter	Regular Cash
10/19/2006	11/2/2006	11/6/2006	11/30/2006	0.3	Quarter	Regular Cash
7/20/2006	8/3/2006	8/7/2006	8/30/2006	0.3	Quarter	Regular Cash
4/20/2006	5/3/2006	5/5/2006	5/30/2006	0.3	Quarter	Regular Cash
1/19/2006	2/2/2006	2/6/2006	2/28/2006	0.3	Quarter	Regular Cash
9/16/2005	11/3/2005	11/7/2005	11/30/2005	0.3	Quarter	Regular Cash
7/21/2005	8/3/2005	8/5/2005	8/30/2005	0.3	Quarter	Regular Cash
3/17/2005	5/3/2005	5/5/2005	5/31/2005	0.3	Quarter	Regular Cash
1/20/2005	2/3/2005	2/7/2005	2/28/2005	0.3	Quarter	Regular Cash

9/16/2004	11/3/2004	11/5/2004	11/30/2004	0.3	Quarter	Regular Cash
7/15/2004	8/3/2004	8/5/2004	8/30/2004	0.3	Quarter	Regular Cash
3/18/2004	5/3/2004	5/5/2004	6/1/2004	0.3	Quarter	Regular Cash
1/15/2004	2/3/2004	2/5/2004	3/1/2004	0.3	Quarter	Regular Cash
9/18/2003	11/3/2003	11/5/2003	12/1/2003	0.3	Quarter	Regular Cash
7/17/2003	8/1/2003	8/5/2003	9/2/2003	0.465	Quarter	Regular Cash
3/20/2003	5/1/2003	5/5/2003	5/30/2003	0.465	Quarter	Regular Cash
1/16/2003	2/3/2003	2/5/2003	2/28/2003	0.465	Quarter	Regular Cash
9/20/2002	11/1/2002	11/5/2002	11/29/2002	0.465	Quarter	Regular Cash
7/19/2002	8/1/2002	8/5/2002	8/30/2002	0.465	Quarter	Regular Cash
3/22/2002	5/2/2002	5/6/2002	5/30/2002	0.465	Quarter	Regular Cash
1/17/2002	2/1/2002	2/5/2002	2/28/2002	0.465	Quarter	Regular Cash
9/20/2001	11/1/2001	11/5/2001	11/30/2001	0.465	Quarter	Regular Cash
7/19/2001	8/2/2001	8/6/2001	8/30/2001	0.465	Quarter	Regular Cash
3/15/2001	5/2/2001	5/4/2001	5/30/2001	0.465	Quarter	Regular Cash
1/18/2001	2/1/2001	2/5/2001	2/28/2001	0.465	Quarter	Regular Cash
9/21/2000	11/2/2000	11/6/2000	11/30/2000	0.465	Quarter	Regular Cash
7/20/2000	8/2/2000	8/4/2000	8/30/2000	0.465	Quarter	Regular Cash
3/16/2000	5/3/2000	5/5/2000	5/30/2000	0.465	Quarter	Regular Cash
1/20/2000	1/24/2000	1/26/2000	2/22/2000	0.465	Quarter	Regular Cash
9/9/1999	10/21/1999	10/25/1999	11/19/1999	0.465	Quarter	Regular Cash
7/8/1999	7/22/1999	7/26/1999	8/20/1999	0.465	Quarter	Regular Cash
3/11/1999	4/22/1999	4/26/1999	5/20/1999	0.465	Quarter	Regular Cash
1/14/1999	1/21/1999	1/25/1999	2/19/1999	0.465	Quarter	Regular Cash
9/10/1998	10/22/1998	10/26/1998	11/20/1998	0.465	Quarter	Regular Cash
7/9/1998	7/22/1998	7/24/1998	8/20/1998	0.465	Quarter	Regular Cash
3/12/1998	4/22/1998	4/24/1998	5/20/1998	0.465	Quarter	Regular Cash
1/8/1998	1/22/1998	1/26/1998	2/20/1998	0.465	Quarter	Regular Cash
9/11/1997	10/22/1997	10/24/1997	11/20/1997	0.465	Quarter	Regular Cash
7/10/1997	7/23/1997	7/25/1997	8/20/1997	0.465	Quarter	Regular Cash
3/13/1997	4/23/1997	4/25/1997	5/20/1997	0.465	Quarter	Regular Cash
1/9/1997	1/22/1997	1/24/1997	2/20/1997	0.465	Quarter	Regular Cash
9/12/1996	10/23/1996	10/25/1996	11/20/1996	0.465	Quarter	Regular Cash
7/12/1996	7/23/1996	7/25/1996	8/20/1996	0.465	Quarter	Regular Cash
3/14/1996	4/23/1996	4/25/1996	5/20/1996	0.465	Quarter	Regular Cash
1/11/1996	1/23/1996	1/25/1996	2/20/1996	0.465	Quarter	Regular Cash
9/14/1995	10/23/1995	10/25/1995	11/20/1995	0.465	Quarter	Regular Cash
7/13/1995	7/21/1995	7/25/1995	8/21/1995	0.465	Quarter	Regular Cash
3/9/1995	4/19/1995	4/25/1995	5/19/1995	0.465	Quarter	Regular Cash
1/12/1995	1/19/1995	1/25/1995	2/21/1995	0.465	Quarter	Regular Cash
9/8/1994	10/19/1994	10/25/1994	11/21/1994	0.465	Quarter	Regular Cash
7/14/1994	7/19/1994	7/25/1994	8/19/1994	0.465	Quarter	Regular Cash
3/10/1994	4/19/1994	4/25/1994	5/20/1994	0.465	Quarter	Regular Cash
1/13/1994	1/19/1994	1/25/1994	2/22/1994	0.465	Quarter	Regular Cash
9/9/1993	10/19/1993	10/25/1993	11/19/1993	0.465	Quarter	Regular Cash
7/8/1993	7/20/1993	7/26/1993	8/20/1993	0.465	Quarter	Regular Cash
3/11/1993	4/20/1993	4/26/1993	5/20/1993	0.465	Quarter	Regular Cash
1/14/1993	1/19/1993	1/25/1993	2/19/1993	0.465	Quarter	Regular Cash
9/10/1992	10/20/1992	10/26/1992	11/20/1992	0.465	Quarter	Regular Cash
7/9/1992	7/20/1992	7/24/1992	8/20/1992	0.465	Quarter	Regular Cash
3/12/1992	4/20/1992	4/24/1992	5/20/1992	0.465	Quarter	Regular Cash
1/9/1992	1/17/1992	1/24/1992	2/20/1992	0.465	Quarter	Regular Cash
9/12/1991	10/21/1991	10/25/1991	11/20/1991	0.465	Quarter	Regular Cash
7/11/1991	7/19/1991	7/25/1991	8/20/1991	0.465	Quarter	Regular Cash
3/14/1991	4/19/1991	4/25/1991	5/20/1991	0.465	Quarter	Regular Cash
1/10/1990	1/18/1991	1/25/1991	2/20/1991	0.465	Quarter	Regular Cash
9/13/1990	10/19/1990	10/25/1990	11/20/1990	0.465	Quarter	Regular Cash
7/12/1990	7/19/1990	7/25/1990	8/20/1990	0.465	Quarter	Regular Cash
3/8/1990	4/19/1990	4/25/1990	5/21/1990	0.465	Quarter	Regular Cash
1/11/1990	1/19/1990	1/25/1990	2/20/1990	0.465	Quarter	Regular Cash
9/14/1989	10/19/1989	10/25/1989	11/20/1989	0.465	Quarter	Regular Cash
7/13/1989	7/19/1989	7/25/1989	8/21/1989	0.465	Quarter	Regular Cash
3/9/1989	4/19/1989	4/25/1989	5/20/1989	0.45	Quarter	Regular Cash
1/9/1989	1/19/1989	1/25/1989	2/21/1989	0.45	Quarter	Regular Cash
9/7/1988	10/19/1988	10/25/1988	11/21/1988	0.45	Quarter	Regular Cash
7/14/1988	7/19/1988	7/25/1988	8/20/1988	0.45	Quarter	Regular Cash

3/10/1988	4/19/1988	4/25/1988	5/20/1988	0.45	Quarter	Regular Cash
1/14/1988	1/19/1988	1/25/1988	2/20/1988	0.45	Quarter	Regular Cash
9/9/1987	10/20/1987	10/26/1987	11/20/1987	0.45	Quarter	Regular Cash
7/9/1987	7/20/1987	7/24/1987	8/20/1987	0.45	Quarter	Regular Cash
3/12/1987	4/20/1987	4/24/1987	5/20/1987	0.45	Quarter	Regular Cash
1/8/1987	1/20/1987	1/26/1987	2/20/1987	0.45	Quarter	Regular Cash
9/11/1986	10/20/1986	10/24/1986	11/20/1986	0.45	Quarter	Regular Cash
7/10/1986	7/21/1986	7/25/1986	8/20/1986	0.45	Quarter	Regular Cash
3/13/1986	4/21/1986	4/25/1986	5/20/1986	0.43	Quarter	Regular Cash
1/8/1986	1/17/1986	1/24/1986	2/20/1986	0.43	Quarter	Regular Cash
9/12/1985	10/21/1985	10/25/1985	11/20/1985	0.43	Quarter	Regular Cash
7/11/1985	7/19/1985	7/25/1985	8/20/1985	0.43	Quarter	Regular Cash
3/14/1985	4/19/1985	4/25/1985	5/20/1985	0.41	Quarter	Regular Cash
1/10/1985	1/18/1985	1/25/1985	2/20/1985	0.41	Quarter	Regular Cash
9/14/1984	10/19/1984	10/25/1984	11/20/1984	0.41	Quarter	Regular Cash
7/13/1984	7/19/1984	7/25/1984	8/20/1984	0.41	Quarter	Regular Cash
3/9/1984	4/18/1984	4/25/1984	5/21/1984	0.385	Quarter	Regular Cash
1/16/1984	1/19/1984	1/25/1984	2/21/1984	0.385	Quarter	Regular Cash
9/12/1983	10/19/1983	10/25/1983	11/21/1983	0.385	Quarter	Regular Cash
7/18/1983	7/19/1983	7/25/1983	8/20/1983	0.385	Quarter	Regular Cash
3/14/1983	4/19/1983	4/25/1983	5/20/1983	0.36	Quarter	Regular Cash
1/17/1983	1/19/1983	1/25/1983	2/19/1983	0.36	Quarter	Regular Cash
9/10/1982	10/19/1982	10/25/1982	11/20/1982	0.36	Quarter	Regular Cash
7/12/1982	7/20/1982	7/26/1982	8/20/1982	0.36	Quarter	Regular Cash
3/15/1982	4/20/1982	4/26/1982	5/20/1982	0.33	Quarter	Regular Cash
1/18/1982	1/19/1982	1/25/1982	2/20/1982	0.33	Quarter	Regular Cash
9/11/1981	10/20/1981	10/26/1981	11/20/1981	0.33	Quarter	Regular Cash
7/13/1981	7/21/1981	7/27/1981	8/20/1981	0.33	Quarter	Regular Cash
3/13/1981	4/21/1981	4/27/1981	5/20/1981	0.315	Quarter	Regular Cash
1/9/1981	1/20/1981	1/26/1981	2/20/1981	0.315	Quarter	Regular Cash
9/12/1980	10/21/1980	10/27/1980	11/20/1980	0.315	Quarter	Regular Cash
7/14/1980	7/21/1980	7/25/1980	8/20/1980	0.315	Quarter	Regular Cash
3/14/1980	4/21/1980	4/25/1980	5/20/1980	0.3	Quarter	Regular Cash
1/14/1980	1/21/1980	1/25/1980	2/20/1980	0.3	Quarter	Regular Cash

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4/24/2018	6/14/2018	6/15/2018	6/29/2018	0.55	Quarter	Regular Cash
2/12/2018	3/14/2018	3/15/2018	3/29/2018	0.55	Quarter	Regular Cash
11/1/2017	12/14/2017	12/15/2017	12/29/2017	0.525	Quarter	Regular Cash
7/25/2017	9/14/2017	9/15/2017	9/29/2017	0.525	Quarter	Regular Cash
4/26/2017	6/13/2017	6/15/2017	6/30/2017	0.525	Quarter	Regular Cash
2/16/2017	3/13/2017	3/15/2017	3/31/2017	0.525	Quarter	Regular Cash
10/20/2016	12/13/2016	12/15/2016	12/30/2016	0.5	Quarter	Regular Cash
7/22/2016	9/13/2016	9/15/2016	9/30/2016	0.5	Quarter	Regular Cash
4/20/2016	6/13/2016	6/15/2016	6/30/2016	0.5	Quarter	Regular Cash
2/11/2016	3/11/2016	3/15/2016	3/31/2016	0.5	Quarter	Regular Cash
10/22/2015	12/11/2015	12/15/2015	12/31/2015	0.48	Quarter	Regular Cash
7/23/2015	9/11/2015	9/15/2015	9/30/2015	0.48	Quarter	Regular Cash
4/23/2015	6/11/2015	6/15/2015	6/30/2015	0.48	Quarter	Regular Cash
2/12/2015	3/11/2015	3/13/2015	3/31/2015	0.48	Quarter	Regular Cash
10/23/2014	12/11/2014	12/15/2014	12/31/2014	0.4	Quarter	Regular Cash
7/24/2014	9/11/2014	9/15/2014	9/30/2014	0.4	Quarter	Regular Cash
4/24/2014	6/11/2014	6/13/2014	6/30/2014	0.4	Quarter	Regular Cash
2/19/2014	3/12/2014	3/14/2014	3/31/2014	0.4	Quarter	Regular Cash
10/24/2013	12/11/2013	12/13/2013	12/31/2013	0.38	Quarter	Regular Cash
7/25/2013	9/11/2013	9/13/2013	9/30/2013	0.38	Quarter	Regular Cash
4/25/2013	6/12/2013	6/14/2013	6/30/2013	0.38	Quarter	Regular Cash
2/14/2013	3/13/2013	3/15/2013	3/31/2013	0.38	Quarter	Regular Cash
10/24/2012	12/12/2012	12/14/2012	12/31/2012	0.37	Quarter	Regular Cash
7/24/2012	9/12/2012	9/15/2012	9/30/2012	0.37	Quarter	Regular Cash
4/25/2012	6/13/2012	6/15/2012	6/30/2012	0.37	Quarter	Regular Cash
2/16/2012	3/13/2012	3/15/2012	3/31/2012	0.37	Quarter	Regular Cash
10/26/2011	12/13/2011	12/15/2011	12/31/2011	0.36	Quarter	Regular Cash
7/27/2011	9/13/2011	9/15/2011	9/30/2011	0.36	Quarter	Regular Cash
4/27/2011	6/13/2011	6/15/2011	6/30/2011	0.36	Quarter	Regular Cash
2/11/2011	3/11/2011	3/15/2011	3/31/2011	0.36	Quarter	Regular Cash
10/28/2010	12/13/2010	12/15/2010	12/31/2010	0.34	Quarter	Regular Cash
7/29/2010	9/13/2010	9/15/2010	9/30/2010	0.34	Quarter	Regular Cash
4/23/2010	6/11/2010	6/15/2010	6/30/2010	0.34	Quarter	Regular Cash
2/12/2010	3/11/2010	3/15/2010	3/31/2010	0.34	Quarter	Regular Cash
10/28/2009	12/11/2009	12/15/2009	12/31/2009	0.335	Quarter	Regular Cash
7/30/2009	9/11/2009	9/15/2009	9/30/2009	0.335	Quarter	Regular Cash
4/23/2009	6/11/2009	6/15/2009	6/30/2009	0.335	Quarter	Regular Cash
2/13/2009	3/11/2009	3/15/2009	3/31/2009	0.335	Quarter	Regular Cash
10/30/2008	12/11/2008	12/15/2008	12/31/2008	0.33	Quarter	Regular Cash
7/31/2008	9/11/2008	9/15/2008	9/30/2008	0.33	Quarter	Regular Cash
5/21/2008	6/11/2008	6/15/2008	6/30/2008	0.33	Quarter	Regular Cash
2/29/2008	3/12/2008	3/15/2008	3/31/2008	0.33	Quarter	Regular Cash
10/31/2007	12/12/2007	12/15/2007	12/31/2007	0.33	Quarter	Regular Cash
8/8/2007	9/12/2007	9/15/2007	9/30/2007	0.33	Quarter	Regular Cash
5/24/2007	6/13/2007	6/15/2007	6/30/2007	0.31	Quarter	Regular Cash
2/28/2007	3/13/2007	3/15/2007	3/31/2007	0.31	Quarter	Regular Cash
11/2/2006	12/13/2006	12/15/2006	12/31/2006	0.31	Quarter	Regular Cash
8/2/2006	9/13/2006	9/15/2006	9/30/2006	0.31	Quarter	Regular Cash
5/4/2006	6/13/2006	6/15/2006	6/30/2006	0.31	Quarter	Regular Cash
3/6/2006	3/13/2006	3/15/2006	3/31/2006	0.31	Quarter	Regular Cash
11/9/2005	12/13/2005	12/15/2005	12/31/2005	0.31	Quarter	Regular Cash
7/14/2005	9/13/2005	9/15/2005	9/30/2005	0.25	Quarter	Regular Cash
5/23/2005	6/13/2005	6/15/2005	6/30/2005	0.22	Quarter	Regular Cash
3/10/2005	3/22/2005	3/24/2005	3/31/2005	0.22	Quarter	Regular Cash

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5/17/2018	7/9/2018	7/10/2018	7/30/2018	0.3325	Quarter	Regular Cash
2/21/2018	4/9/2018	4/10/2018	4/30/2018	0.3325	Quarter	Regular Cash
11/29/2017	1/9/2018	1/10/2018	1/30/2018	0.3325	Quarter	Regular Cash
9/26/2017	10/6/2017	10/10/2017	10/30/2017	0.3325	Quarter	Regular Cash
5/18/2017	7/6/2017	7/10/2017	7/28/2017	0.3025	Quarter	Regular Cash
2/22/2017	4/6/2017	4/10/2017	4/28/2017	0.3025	Quarter	Regular Cash
11/30/2016	1/6/2017	1/10/2017	1/30/2017	0.3025	Quarter	Regular Cash
9/28/2016	10/6/2016	10/11/2016	10/28/2016	0.3025	Quarter	Regular Cash
5/19/2016	7/6/2016	7/8/2016	7/29/2016	0.275	Quarter	Regular Cash
2/25/2016	4/6/2016	4/8/2016	4/29/2016	0.275	Quarter	Regular Cash
12/2/2015	1/6/2016	1/8/2016	1/29/2016	0.275	Quarter	Regular Cash
9/30/2015	10/7/2015	10/12/2015	10/30/2015	0.275	Quarter	Regular Cash
5/14/2015	7/8/2015	7/10/2015	7/30/2015	0.25	Quarter	Regular Cash
2/25/2015	4/8/2015	4/10/2015	4/30/2015	0.25	Quarter	Regular Cash
12/3/2014	1/7/2015	1/9/2015	1/30/2015	0.25	Quarter	Regular Cash
9/24/2014	10/8/2014	10/10/2014	10/30/2014	0.25	Quarter	Regular Cash
5/15/2014	7/8/2014	7/10/2014	7/30/2014	0.225	Quarter	Regular Cash
2/12/2014	4/8/2014	4/10/2014	4/30/2014	0.225	Quarter	Regular Cash
12/4/2013	1/8/2014	1/10/2014	1/30/2014	0.225	Quarter	Regular Cash
9/25/2013	10/8/2013	10/10/2013	10/30/2013	0.2088	Quarter	Regular Cash
5/16/2013	7/9/2013	7/11/2013	7/30/2013	0.2088	Quarter	Regular Cash
2/26/2013	4/8/2013	4/10/2013	4/30/2013	0.2088	Quarter	Regular Cash
11/28/2012	1/8/2013	1/10/2013	1/30/2013	0.2088	Quarter	Regular Cash
9/26/2012	10/5/2012	10/10/2012	10/30/2012	0.1963	Quarter	Regular Cash
5/17/2012	7/6/2012	7/10/2012	7/30/2012	0.1963	Quarter	Regular Cash
2/15/2012	4/5/2012	4/10/2012	4/30/2012	0.1963	Quarter	Regular Cash
12/1/2011	1/6/2012	1/10/2012	1/30/2012	0.1963	Quarter	Regular Cash
7/19/2011	10/5/2011	10/7/2011	10/28/2011	0.1875	Quarter	Regular Cash
5/19/2011	7/6/2011	7/8/2011	7/29/2011	0.1875	Quarter	Regular Cash
2/16/2011	4/6/2011	4/8/2011	4/29/2011	0.1875	Quarter	Regular Cash
12/2/2010	1/6/2011	1/10/2011	1/28/2011	0.1875	Quarter	Regular Cash
9/28/2010	10/6/2010	10/8/2010	10/29/2010	0.1813	Quarter	Regular Cash
5/20/2010	7/7/2010	7/9/2010	7/30/2010	0.1813	Quarter	Regular Cash
2/17/2010	4/7/2010	4/9/2010	4/30/2010	0.1813	Quarter	Regular Cash
12/3/2009	1/6/2010	1/8/2010	1/29/2010	0.1813	Quarter	Regular Cash
9/30/2009	10/7/2009	10/9/2009	10/30/2009	0.1775	Quarter	Regular Cash
5/21/2009	7/8/2009	7/10/2009	7/30/2009	0.1775	Quarter	Regular Cash
2/12/2009	4/7/2009	4/9/2009	4/30/2009	0.1775	Quarter	Regular Cash
12/3/2008	1/7/2009	1/9/2009	1/30/2009	0.1775	Quarter	Regular Cash
9/30/2008	10/8/2008	10/10/2008	10/30/2008	0.1738	Quarter	Regular Cash
5/22/2008	7/8/2008	7/10/2008	7/30/2008	0.1738	Quarter	Regular Cash
2/27/2008	4/8/2008	4/10/2008	4/30/2008	0.1738	Quarter	Regular Cash
11/28/2007	1/8/2008	1/10/2008	1/30/2008	0.1738	Quarter	Regular Cash
9/21/2007	10/5/2007	10/10/2007	10/30/2007	0.17	Quarter	Regular Cash
5/17/2007	7/6/2007	7/10/2007	7/30/2007	0.17	Quarter	Regular Cash
2/15/2007	4/5/2007	4/10/2007	4/30/2007	0.17	Quarter	Regular Cash
11/15/2006	1/8/2007	1/10/2007	1/30/2007	0.17	Quarter	Regular Cash
9/20/2006	10/5/2006	10/10/2006	10/30/2006	0.1663	Quarter	Regular Cash
5/18/2006	7/6/2006	7/10/2006	7/28/2006	0.1663	Quarter	Regular Cash
2/22/2006	4/6/2006	4/10/2006	4/28/2006	0.1663	Quarter	Regular Cash
11/17/2005	1/6/2006	1/10/2006	1/30/2006	0.1663	Quarter	Regular Cash
9/21/2005	10/5/2005	10/7/2005	10/28/2005	0.1663	Quarter	Regular Cash
5/20/2005	7/6/2005	7/8/2005	7/29/2005	0.1663	Quarter	Regular Cash
2/23/2005	4/6/2005	4/8/2005	4/29/2005	0.1663	Quarter	Regular Cash

11/17/2004	1/5/2005	1/7/2005	1/28/2005	0.1663	Quarter	Regular Cash
9/15/2004	10/6/2004	10/8/2004	10/29/2004	0.1663	Quarter	Regular Cash
5/20/2004	7/7/2004	7/10/2004	7/30/2004	0.1663	Quarter	Regular Cash
3/3/2004	4/6/2004	4/9/2004	4/30/2004	0.1663	Quarter	Regular Cash
11/19/2003	1/7/2004	1/9/2004	1/30/2004	0.1663	Quarter	Regular Cash
9/30/2003	10/8/2003	10/10/2003	10/30/2003	0.1663	Quarter	Regular Cash
5/22/2003	7/8/2003	7/10/2003	7/30/2003	0.1663	Quarter	Regular Cash
3/26/2003	4/8/2003	4/10/2003	4/30/2003	0.1663	Quarter	Regular Cash
11/20/2002	1/8/2003	1/10/2003	1/30/2003	0.1663	Quarter	Regular Cash
9/18/2002	10/8/2002	10/10/2002	10/30/2002	0.1663	Quarter	Regular Cash
5/16/2002	7/8/2002	7/10/2002	7/30/2002	0.1663	Quarter	Regular Cash
3/20/2002	4/8/2002	4/10/2002	4/30/2002	0.1663	Quarter	Regular Cash
11/16/2001	1/8/2002	1/10/2002	1/30/2002	0.1663	Quarter	Regular Cash
9/19/2001	10/5/2001	10/10/2001	10/30/2001	0.1663	Quarter	Regular Cash
5/24/2001	7/6/2001	7/10/2001	7/30/2001	0.1663	Quarter	Regular Cash
3/21/2001	4/6/2001	4/10/2001	4/30/2001	0.1663	Quarter	Regular Cash
11/15/2000	1/8/2001	1/10/2001	1/30/2001	0.1663	Quarter	Regular Cash
9/20/2000	10/5/2000	10/10/2000	10/30/2000	0.1663	Quarter	Regular Cash
5/18/2000	7/6/2000	7/10/2000	7/28/2000	0.1663	Quarter	Regular Cash
3/22/2000	4/6/2000	4/10/2000	4/28/2000	0.1663	Quarter	Regular Cash
11/17/1999	1/6/2000	1/10/2000	1/28/2000	0.1663	Quarter	Regular Cash
9/15/1999	10/6/1999	10/8/1999	10/29/1999	0.1663	Quarter	Regular Cash
5/27/1999	7/7/1999	7/9/1999	7/30/1999	0.1663	Quarter	Regular Cash
3/17/1999	4/7/1999	4/9/1999	4/30/1999	0.1663	Quarter	Regular Cash
11/18/1998	1/6/1999	1/8/1999	1/29/1999	0.1663	Quarter	Regular Cash
9/16/1998	10/7/1998	10/9/1998	10/30/1998	0.1663	Quarter	Regular Cash
5/21/1998	7/8/1998	7/10/1998	7/30/1998	0.1663	Quarter	Regular Cash
3/25/1998	4/7/1998	4/10/1998	4/30/1998	0.1663	Quarter	Regular Cash
11/19/1997	1/7/1998	1/9/1998	1/30/1998	0.1663	Quarter	Regular Cash
9/17/1997	10/8/1997	10/10/1997	10/30/1997	0.1663	Quarter	Regular Cash
5/16/1997	7/8/1997	7/10/1997	7/30/1997	0.1663	Quarter	Regular Cash
3/19/1997	4/8/1997	4/10/1997	4/30/1997	0.1663	Quarter	Regular Cash
11/21/1996	1/8/1997	1/10/1997	1/30/1997	0.1663	Quarter	Regular Cash
9/18/1996	10/8/1996	10/10/1996	10/30/1996	0.1663	Quarter	Regular Cash
5/21/1996	7/8/1996	7/10/1996	7/30/1996	0.1663	Quarter	Regular Cash
3/25/1996	4/8/1996	4/10/1996	4/30/1996	0.1663	Quarter	Regular Cash
11/20/1995	1/8/1996	1/10/1996	1/30/1996	0.1663	Quarter	Regular Cash
9/21/1995	10/5/1995	10/10/1995	10/30/1995	0.1663	Quarter	Regular Cash
5/19/1995	7/6/1995	7/10/1995	7/28/1995	0.1663	Quarter	Regular Cash
3/15/1995	4/4/1995	4/10/1995	4/28/1995	0.1663	Quarter	Regular Cash
11/8/1994	1/4/1995	1/10/1995	1/30/1995	0.1663	Quarter	Regular Cash
9/14/1994	10/3/1994	10/7/1994	10/28/1994	0.1663	Quarter	Regular Cash
6/21/1994	7/1/1994	7/8/1994	7/29/1994	0.1663	Quarter	Regular Cash
3/8/1994	4/4/1994	4/8/1994	4/29/1994	0.1663	Quarter	Regular Cash
12/14/1993	1/4/1994	1/10/1994	1/28/1994	0.1663	Quarter	Regular Cash
9/14/1993	10/4/1993	10/8/1993	10/29/1993	0.1663	Quarter	Regular Cash
6/15/1993	7/2/1993	7/9/1993	7/30/1993	0.1663	Quarter	Regular Cash
3/9/1993	4/2/1993	4/8/1993	4/30/1993	0.1663	Quarter	Regular Cash
12/8/1992	1/4/1993	1/8/1993	1/29/1993	0.1663	Quarter	Regular Cash
9/8/1992	10/5/1992	10/9/1992	10/30/1992	0.1663	Quarter	Regular Cash
6/9/1992	7/6/1992	7/10/1992	7/30/1992	0.1663	Quarter	Regular Cash
3/10/1992	4/6/1992	4/10/1992	4/30/1992	0.1663	Quarter	Regular Cash
12/10/1991	1/6/1992	1/10/1992	1/30/1992	0.1663	Quarter	Regular Cash
9/10/1991	10/4/1991	10/10/1991	10/30/1991	0.1613	Quarter	Regular Cash
6/11/1991	7/3/1991	7/10/1991	7/30/1991	0.1613	Quarter	Regular Cash
3/13/1991	4/4/1991	4/10/1991	4/30/1991	0.1613	Quarter	Regular Cash
12/11/1990	1/4/1991	1/10/1991	1/30/1991	0.1613	Quarter	Regular Cash
9/11/1990	10/3/1990	10/10/1990	10/30/1990	0.155	Quarter	Regular Cash
6/12/1990	7/3/1990	7/10/1990	7/30/1990	0.155	Quarter	Regular Cash
3/14/1990	4/4/1990	4/10/1990	4/30/1990	0.155	Quarter	Regular Cash
12/12/1989	1/4/1990	1/10/1990	1/30/1990	0.155	Quarter	Regular Cash
9/12/1989	10/3/1989	10/10/1989	10/30/1989	0.1488	Quarter	Regular Cash
6/13/1989	7/5/1989	7/11/1989	7/28/1989	0.1488	Quarter	Regular Cash
3/14/1989	4/4/1989	4/10/1989	4/28/1989	0.1488	Quarter	Regular Cash
12/13/1988	1/4/1989	1/10/1989	1/30/1989	0.1488	Quarter	Regular Cash
9/13/1988	10/4/1988	10/11/1988	10/28/1988	0.1425	Quarter	Regular Cash

6/21/1988	7/5/1988	7/11/1988	7/29/1988	0.1425	Quarter	Regular Cash
3/8/1988	4/5/1988	4/11/1988	4/29/1988	0.1425	Quarter	Regular Cash
12/8/1987	1/4/1988	1/8/1988	1/29/1988	0.1425	Quarter	Regular Cash
9/8/1987	10/5/1987	10/9/1987	10/30/1987	0.1363	Quarter	Regular Cash
6/16/1987	7/6/1987	7/10/1987	7/30/1987	0.1363	Quarter	Regular Cash
3/10/1987	4/6/1987	4/10/1987	4/30/1987	0.1363	Quarter	Regular Cash
12/9/1986	1/5/1987	1/9/1987	1/30/1987	0.1363	Quarter	Regular Cash
9/9/1986	10/6/1986	10/10/1986	10/30/1986	0.13	Quarter	Regular Cash
6/12/1986	7/3/1986	7/10/1986	7/30/1986	0.13	Quarter	Regular Cash
3/11/1986	4/4/1986	4/10/1986	4/30/1986	0.13	Quarter	Regular Cash
12/10/1985	1/6/1986	1/10/1986	1/30/1986	0.13	Quarter	Regular Cash
9/10/1985	10/4/1985	10/10/1985	10/30/1985	0.125	Quarter	Regular Cash
6/18/1985	7/3/1985	7/10/1985	7/30/1985	0.125	Quarter	Regular Cash
3/12/1985	4/3/1985	4/10/1985	4/30/1985	0.125	Quarter	Regular Cash
12/11/1984	1/4/1985	1/10/1985	1/30/1985	0.125	Quarter	Regular Cash
9/13/1984	10/3/1984	10/10/1984	10/30/1984	0.12	Quarter	Regular Cash
6/14/1984	7/3/1984	7/10/1984	7/30/1984	0.12	Quarter	Regular Cash
3/14/1984	4/4/1984	4/10/1984	4/30/1984	0.12	Quarter	Regular Cash
12/14/1983	1/4/1984	1/10/1984	1/30/1984	0.12	Quarter	Regular Cash
9/14/1983	10/3/1983	10/7/1983	10/28/1983	0.115	Quarter	Regular Cash
6/16/1983	7/1/1983	7/8/1983	7/29/1983	0.115	Quarter	Regular Cash
3/10/1983	4/4/1983	4/8/1983	4/29/1983	0.115	Quarter	Regular Cash
12/9/1982	1/4/1983	1/10/1983	1/28/1983	0.115	Quarter	Regular Cash
9/15/1982	10/4/1982	10/8/1982	10/29/1982	0.11	Quarter	Regular Cash
6/10/1982	7/2/1982	7/9/1982	7/30/1982	0.11	Quarter	Regular Cash
3/11/1982	4/2/1982	4/8/1982	4/30/1982	0.11	Quarter	Regular Cash
12/10/1981	1/4/1982	1/8/1982	1/29/1982	0.11	Quarter	Regular Cash
9/9/1981	10/5/1981	10/9/1981	10/30/1981	0.105	Quarter	Regular Cash
6/11/1981	7/6/1981	7/10/1981	7/30/1981	0.105	Quarter	Regular Cash
3/12/1981	4/6/1981	4/10/1981	4/30/1981	0.105	Quarter	Regular Cash
12/10/1980	1/5/1981	1/9/1981	1/30/1981	0.105	Quarter	Regular Cash
9/11/1980	10/6/1980	10/10/1980	10/30/1980	0.1	Quarter	Regular Cash
6/18/1980	7/3/1980	7/10/1980	7/30/1980	0.1	Quarter	Regular Cash
3/12/1980	4/3/1980	4/10/1980	4/30/1980	0.1	Quarter	Regular Cash
12/13/1979	1/4/1980	1/10/1980	1/30/1980	0.1	Quarter	Regular Cash

PNM US Equity
DVD_HIST

2/23/2018	5/1/2018	5/2/2018	5/16/2018	0.265	Quarter	Regular Cash
12/1/2017	1/17/2018	1/18/2018	2/1/2018	0.265	Quarter	Regular Cash
9/19/2017	10/27/2017	10/30/2017	11/14/2017	0.2425	Quarter	Regular Cash
7/27/2017	8/3/2017	8/7/2017	8/14/2017	0.2425	Quarter	Regular Cash
2/24/2017	4/27/2017	5/1/2017	5/15/2017	0.2425	Quarter	Regular Cash
12/13/2016	1/19/2017	1/23/2017	2/13/2017	0.2425	Quarter	Regular Cash
9/20/2016	10/27/2016	10/31/2016	11/14/2016	0.22	Quarter	Regular Cash
7/26/2016	8/4/2016	8/8/2016	8/22/2016	0.22	Quarter	Regular Cash
2/25/2016	4/6/2016	4/8/2016	5/13/2016	0.22	Quarter	Regular Cash
12/10/2015	1/21/2016	1/25/2016	2/12/2016	0.22	Quarter	Regular Cash
9/15/2015	10/29/2015	11/2/2015	11/13/2015	0.2	Quarter	Regular Cash
7/14/2015	7/30/2015	8/3/2015	8/14/2015	0.2	Quarter	Regular Cash
2/26/2015	4/8/2015	4/10/2015	5/15/2015	0.2	Quarter	Regular Cash
12/9/2014	1/26/2015	1/28/2015	2/13/2015	0.2	Quarter	Regular Cash
9/16/2014	10/29/2014	10/31/2014	11/14/2014	0.185	Quarter	Regular Cash
7/15/2014	7/30/2014	8/1/2014	8/15/2014	0.185	Quarter	Regular Cash
2/27/2014	4/15/2014	4/18/2014	5/15/2014	0.185	Quarter	Regular Cash
12/6/2013	1/21/2014	1/23/2014	2/14/2014	0.185	Quarter	Regular Cash
9/17/2013	11/4/2013	11/6/2013	11/15/2013	0.165	Quarter	Regular Cash
7/16/2013	7/31/2013	8/2/2013	8/15/2013	0.165	Quarter	Regular Cash
2/28/2013	4/17/2013	4/19/2013	5/15/2013	0.165	Quarter	Regular Cash
12/11/2012	1/17/2013	1/22/2013	2/15/2013	0.145	Quarter	Regular Cash
9/19/2012	10/31/2012	11/1/2012	11/15/2012	0.145	Quarter	Regular Cash
7/17/2012	7/30/2012	8/1/2012	8/15/2012	0.145	Quarter	Regular Cash
2/29/2012	3/30/2012	4/3/2012	5/15/2012	0.145	Quarter	Regular Cash
12/6/2011	1/23/2012	1/25/2012	2/15/2012	0.125	Quarter	Regular Cash
9/27/2011	10/28/2011	11/1/2011	11/15/2011	0.125	Quarter	Regular Cash
7/12/2011	7/28/2011	8/1/2011	8/15/2011	0.125	Quarter	Regular Cash
2/17/2011	4/1/2011	4/5/2011	5/16/2011	0.125	Quarter	Regular Cash
12/14/2010	1/24/2011	1/26/2011	2/15/2011	0.125	Quarter	Regular Cash
9/21/2010	10/27/2010	10/29/2010	11/15/2010	0.125	Quarter	Regular Cash
7/20/2010	7/29/2010	8/2/2010	8/16/2010	0.125	Quarter	Regular Cash
2/16/2010	3/31/2010	4/5/2010	5/14/2010	0.125	Quarter	Regular Cash
12/8/2009	1/25/2010	1/27/2010	2/15/2010	0.125	Quarter	Regular Cash
9/15/2009	11/2/2009	11/4/2009	11/18/2009	0.125	Quarter	Regular Cash
7/20/2009	7/29/2009	7/31/2009	8/17/2009	0.125	Quarter	Regular Cash
2/17/2009	4/6/2009	4/8/2009	5/15/2009	0.125	Quarter	Regular Cash
12/9/2008	1/21/2009	1/23/2009	2/13/2009	0.125	Quarter	Regular Cash
9/16/2008	10/29/2008	10/31/2008	11/14/2008	0.125	Quarter	Regular Cash
8/11/2008	8/19/2008	8/21/2008	8/28/2008	0.125	Quarter	Regular Cash
2/19/2008	4/7/2008	4/9/2008	5/2/2008	0.23	Quarter	Regular Cash
12/4/2007	1/30/2008	2/1/2008	2/15/2008	0.23	Quarter	Regular Cash
9/18/2007	10/30/2007	11/1/2007	11/16/2007	0.23	Quarter	Regular Cash
7/17/2007	7/30/2007	8/1/2007	8/17/2007	0.23	Quarter	Regular Cash
2/13/2007	4/27/2007	5/1/2007	5/18/2007	0.23	Quarter	Regular Cash
12/5/2006	1/30/2007	2/1/2007	2/16/2007	0.22	Quarter	Regular Cash
9/26/2006	10/30/2006	11/1/2006	11/17/2006	0.22	Quarter	Regular Cash
7/18/2006	7/28/2006	8/1/2006	8/18/2006	0.22	Quarter	Regular Cash
2/14/2006	4/27/2006	5/1/2006	5/19/2006	0.22	Quarter	Regular Cash
12/6/2005	1/30/2006	2/1/2006	2/17/2006	0.2	Quarter	Regular Cash
9/27/2005	10/28/2005	11/1/2005	11/18/2005	0.2	Quarter	Regular Cash
7/19/2005	7/28/2005	8/1/2005	8/19/2005	0.2	Quarter	Regular Cash
2/15/2005	4/28/2005	5/2/2005	5/20/2005	0.185	Quarter	Regular Cash
12/8/2004	1/28/2005	2/1/2005	2/18/2005	0.185	Quarter	Regular Cash

9/29/2004	10/28/2004	11/1/2004	11/12/2004	0.16	Quarter	Regular Cash
5/18/2004	7/29/2004	8/2/2004	8/13/2004	0.16	Quarter	Regular Cash
2/17/2004	4/29/2004	5/3/2004	5/14/2004	0.16	Quarter	Regular Cash
12/18/2003	1/29/2004	2/2/2004	2/13/2004	0.153333	Quarter	Regular Cash
10/7/2003	10/30/2003	11/3/2003	11/14/2003	0.153333	Quarter	Regular Cash
7/16/2003	7/30/2003	8/1/2003	8/15/2003	0.153333	Quarter	Regular Cash
2/18/2003	4/30/2003	5/2/2003	5/16/2003	0.153333	Quarter	Regular Cash
12/11/2002	1/30/2003	2/3/2003	2/14/2003	0.146667	Quarter	Regular Cash
10/2/2002	10/31/2002	11/4/2002	11/15/2002	0.146667	Quarter	Regular Cash
7/17/2002	7/31/2002	8/2/2002	8/16/2002	0.146667	Quarter	Regular Cash
2/20/2002	4/30/2002	5/2/2002	5/17/2002	0.146667	Quarter	Regular Cash
12/11/2001	1/31/2002	2/4/2002	2/15/2002	0.133333	Quarter	Regular Cash
9/13/2001	10/31/2001	11/2/2001	11/16/2001	0.133333	Quarter	Regular Cash
7/17/2001	7/31/2001	8/2/2001	8/17/2001	0.133333	Quarter	Regular Cash
4/17/2001	4/30/2001	5/2/2001	5/18/2001	0.133333	Quarter	Regular Cash
12/12/2000	1/31/2001	2/2/2001	2/16/2001	0.133333	Quarter	Regular Cash
9/27/2000	10/31/2000	11/2/2000	11/17/2000	0.133333	Quarter	Regular Cash
6/6/2000	7/31/2000	8/2/2000	8/18/2000	0.133333	Quarter	Regular Cash
3/8/2000	4/28/2000	5/2/2000	5/19/2000	0.133333	Quarter	Regular Cash
12/7/1999	1/28/2000	2/1/2000	2/18/2000	0.133333	Quarter	Regular Cash
9/28/1999	10/28/1999	11/1/1999	11/19/1999	0.133333	Quarter	Regular Cash
6/30/1999	7/29/1999	8/2/1999	8/20/1999	0.133333	Quarter	Regular Cash
4/13/1999	4/29/1999	5/3/1999	5/21/1999	0.133333	Quarter	Regular Cash
1/18/1999	1/28/1999	2/1/1999	2/19/1999	0.133333	Quarter	Regular Cash
9/29/1998	10/29/1998	11/2/1998	11/20/1998	0.133333	Quarter	Regular Cash
6/9/1998	7/30/1998	8/3/1998	8/21/1998	0.133333	Quarter	Regular Cash
3/10/1998	4/29/1998	5/1/1998	5/22/1998	0.133333	Quarter	Regular Cash
12/11/1997	1/29/1998	2/2/1998	2/20/1998	0.113333	Quarter	Regular Cash
10/7/1997	10/30/1997	11/3/1997	11/21/1997	0.113333	Quarter	Regular Cash
6/4/1997	7/30/1997	8/1/1997	8/22/1997	0.113333	Quarter	Regular Cash
3/12/1997	5/8/1997	5/12/1997	5/23/1997	0.113333	Quarter	Regular Cash
1/17/1997	1/30/1997	2/3/1997	2/21/1997	0.08	Quarter	Regular Cash
10/10/1996	10/30/1996	11/1/1996	11/22/1996	0.08	Quarter	Regular Cash
7/22/1996	7/30/1996	8/1/1996	8/23/1996	0.08	Quarter	Regular Cash
3/12/1996	4/29/1996	5/1/1996	5/24/1996	0.08	Irreg	Regular Cash
4/14/1989	4/14/1989	#N/A N/A	#N/A N/A	#N/A N/A	Suspend	Discontinued
1/24/1989	1/30/1989	2/3/1989	2/24/1989	0.253333	Quarter	Regular Cash
10/25/1988	10/31/1988	11/4/1988	11/25/1988	0.253333	Quarter	Regular Cash
7/18/1988	8/1/1988	8/5/1988	8/26/1988	0.253333	Quarter	Regular Cash
4/26/1988	5/2/1988	5/6/1988	5/27/1988	0.253333	Quarter	Regular Cash
1/27/1988	2/1/1988	2/5/1988	2/26/1988	0.486667	Quarter	Regular Cash
10/27/1987	11/2/1987	11/6/1987	11/27/1987	0.486667	Quarter	Regular Cash
7/28/1987	8/3/1987	8/7/1987	8/28/1987	0.486667	Quarter	Regular Cash
4/15/1987	5/4/1987	5/8/1987	5/29/1987	0.486667	Quarter	Regular Cash
1/27/1987	2/2/1987	2/6/1987	2/27/1987	0.486667	Quarter	Regular Cash
10/28/1986	11/3/1986	11/7/1986	11/28/1986	0.486667	Quarter	Regular Cash
7/22/1986	7/28/1986	8/1/1986	8/22/1986	0.486667	Quarter	Regular Cash
4/22/1986	4/28/1986	5/2/1986	5/23/1986	0.486667	Quarter	Regular Cash
1/28/1986	2/3/1986	2/7/1986	2/28/1986	0.486667	Quarter	Regular Cash
10/22/1985	10/26/1985	11/1/1985	11/22/1985	0.486667	Quarter	Regular Cash
7/23/1985	7/29/1985	8/2/1985	8/23/1985	0.48	Quarter	Regular Cash
4/23/1985	4/29/1985	5/3/1985	5/24/1985	0.48	Quarter	Regular Cash
1/22/1985	1/28/1985	2/1/1985	2/22/1985	0.48	Quarter	Regular Cash
10/24/1984	10/29/1984	11/2/1984	11/23/1984	0.48	Quarter	Regular Cash
7/26/1984	7/30/1984	8/3/1984	8/24/1984	0.473333	Quarter	Regular Cash
4/27/1984	4/30/1984	5/4/1984	5/25/1984	0.473333	Quarter	Regular Cash
1/26/1984	1/30/1984	2/3/1984	2/24/1984	0.473333	Quarter	Regular Cash
10/27/1983	10/31/1983	11/4/1983	11/25/1983	0.473333	Quarter	Regular Cash
7/28/1983	8/1/1983	8/5/1983	8/26/1983	0.466667	Quarter	Regular Cash
4/28/1983	5/2/1983	5/6/1983	5/27/1983	0.466667	Quarter	Regular Cash
1/27/1983	1/31/1983	2/4/1983	2/25/1983	0.466667	Quarter	Regular Cash
10/28/1982	10/29/1982	11/5/1982	11/26/1982	0.466667	Quarter	Regular Cash
7/29/1982	8/2/1982	8/6/1982	8/27/1982	0.466667	Quarter	Regular Cash
4/28/1982	5/3/1982	5/7/1982	5/28/1982	0.466667	Quarter	Regular Cash
1/28/1982	2/1/1982	2/5/1982	2/26/1982	0.446667	Quarter	Regular Cash
10/29/1981	10/30/1981	11/6/1981	11/27/1981	0.446667	Quarter	Regular Cash

7/30/1981	8/3/1981	8/7/1981	8/28/1981	0.446667	Quarter	Regular Cash
4/30/1981	5/4/1981	5/8/1981	5/29/1981	0.446667	Quarter	Regular Cash
1/15/1981	2/2/1981	2/6/1981	2/27/1981	0.446667	Quarter	Regular Cash
10/30/1980	10/31/1980	11/7/1980	11/28/1980	0.346667	Quarter	Regular Cash
7/24/1980	7/28/1980	8/1/1980	8/22/1980	0.346667	Quarter	Regular Cash
4/22/1980	4/28/1980	5/2/1980	5/23/1980	0.346667	Quarter	Regular Cash
1/24/1980	1/28/1980	2/1/1980	2/22/1980	0.32	Quarter	Regular Cash

Date	5/18/2018

	10 Year YLD	30 Year YLD	Implied 20-Year forward rate in 10 Yrs	
TIPS	0.79	0.95	1.03%	30-trading day average as of 5/18/18
Nominal Treasury	2.95	3.12	3.20%	
Implied Forward			2.15%	
BlueChip 2024-2028 Forecast			2.20%	
			2.18%	
Real GDP			3.21%	
Implied Expected Nominal GDP			5.46%	

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H.15 Selected Interest Rates for May 21, 2018

Series Description	Market yield on U.S. Treasury securities at 10-year constant maturity, quoted on investment basis	Market yield on U.S. Treasury securities at 10-year constant maturity, quoted on investment basis, inflation-indexed	Market yield on U.S. Treasury securities at 20-year constant maturity, quoted on investment basis	Market yield on U.S. Treasury securities at 20-year constant maturity, quoted on investment basis, inflation-indexed	Market yield on U.S. Treasury securities at 30-year constant maturity, quoted on investment basis	Market yield on U.S. Treasury securities at 30-year^ constant maturity, quoted on investment basis,^ inflation-indexed	Market yield on U.S. Treasury securities at 5-year constant maturity, quoted on investment basis	Market yield on U.S. Treasury securities at 5-year constant maturity, quoted on investment basis, inflation-indexed
Unit:	Percent:_Per_Year	Percent:_Per_Year	Percent:_Per_Year	Percent:_Per_Year	Percent:_Per_Year	Percent:_Per_Year	Percent:_Per_Year	Percent:_Per_Year
Multiplier:	1	1	1	1	1	1	1	1
Currency:	NA	NA	NA	NA	NA	NA	NA	NA
Unique Identifier:	H15/H15/RIFLGFCY10_N.B	H15/H15/RIFLGFCY10_XII_N.B	H15/H15/RIFLGFCY20_N.B	H15/H15/RIFLGFCY20_XII_N.B	H15/H15/RIFLGFCY30_N.B	H15/H15/RIFLGFCY30_XII_N.B	H15/H15/RIFLGFCY05_N.B	H15/H15/RIFLGFCY05_XII_N.B
Time Period	RIFLGFCY10_N.B	RIFLGFCY10_XII_N.B	RIFLGFCY20_N.B	RIFLGFCY20_XII_N.B	RIFLGFCY30_N.B	RIFLGFCY30_XII_N.B	RIFLGFCY05_N.B	RIFLGFCY05_XII_N.B
2017-01-02	ND	ND	ND	ND	ND	ND	ND	ND
2017-01-03	2.45	0.47	2.78	0.78	3.04	0.94	1.94	0.08
2017-01-04	2.46	0.47	2.78	0.78	3.05	0.95	1.94	0.08
2017-01-05	2.37	0.42	2.69	0.73	2.96	0.89	1.86	0.03
2017-01-06	2.42	0.46	2.73	0.76	3	0.93	1.92	0.08
2017-01-09	2.38	0.43	2.69	0.74	2.97	0.91	1.89	0.04
2017-01-10	2.38	0.43	2.69	0.74	2.97	0.91	1.89	0.05
2017-01-11	2.38	0.39	2.68	0.71	2.96	0.88	1.89	0.04
2017-01-12	2.36	0.38	2.68	0.7	3.01	0.87	1.87	0
2017-01-13	2.4	0.41	2.71	0.72	2.99	0.89	1.9	0.05
2017-01-16	ND	ND	ND	ND	ND	ND	ND	ND
2017-01-17	2.33	0.36	2.66	0.68	2.93	0.87	1.84	0
2017-01-18	2.42	0.42	2.74	0.74	3	0.92	1.93	0.07
2017-01-19	2.47	0.43	2.77	0.75	3.04	0.93	1.97	0.07
2017-01-20	2.48	0.44	2.79	0.76	3.05	0.94	1.95	0.03
2017-01-23	2.41	0.39	2.72	0.71	2.99	0.89	1.88	0.02
2017-01-24	2.47	0.41	2.78	0.75	3.05	0.93	1.94	0.01
2017-01-25	2.53	0.45	2.84	0.78	3.1	0.96	1.99	0.03
2017-01-26	2.51	0.43	2.82	0.76	3.08	0.94	1.95	0.01
2017-01-27	2.49	0.41	2.8	0.74	3.06	0.91	1.94	-0.02
2017-01-30	2.49	0.42	2.82	0.76	3.08	0.94	1.94	-0.01
2017-01-31	2.45	0.4	2.78	0.74	3.05	0.93	1.9	-0.04
2017-02-01	2.48	0.43	2.8	0.77	3.08	0.96	1.93	0.01
2017-02-02	2.48	0.43	2.8	0.79	3.09	0.98	1.92	-0.01
2017-02-03	2.49	0.44	2.82	0.81	3.11	1.01	1.93	0.02
2017-02-06	2.42	0.4	2.76	0.78	3.05	0.98	1.86	-0.05
2017-02-07	2.4	0.4	2.74	0.76	3.02	0.96	1.85	-0.02
2017-02-08	2.34	0.38	2.68	0.72	2.96	0.91	1.81	-0.01
2017-02-09	2.4	0.41	2.74	0.75	3.02	0.93	1.88	0.02
2017-02-10	2.41	0.4	2.75	0.72	3.01	0.9	1.89	0.02
2017-02-13	2.43	0.43	2.77	0.74	3.03	0.91	1.92	0.05
2017-02-14	2.47	0.46	2.81	0.77	3.07	0.94	1.98	0.11
2017-02-15	2.51	0.45	2.84	0.76	3.09	0.93	2.01	0.08
2017-02-16	2.45	0.43	2.8	0.75	3.05	0.95	1.95	0.05
2017-02-17	2.42	0.41	2.78	0.72	3.03	0.91	1.92	0.07
2017-02-20	ND	ND	ND	ND	ND	ND	ND	ND
2017-02-21	2.43	0.4	2.78	0.72	3.04	0.92	1.93	0.06
2017-02-22	2.42	0.38	2.78	0.71	3.04	0.91	1.92	0
2017-02-23	2.38	0.35	2.75	0.69	3.02	0.89	1.87	-0.03
2017-02-24	2.31	0.31	2.69	0.64	2.95	0.85	1.8	-0.1
2017-02-27	2.36	0.35	2.72	0.67	2.98	0.88	1.87	0.01
2017-02-28	2.36	0.34	2.7	0.66	2.97	0.87	1.89	0
2017-03-01	2.46	0.43	2.81	0.75	3.06	0.94	1.99	0.15
2017-03-02	2.49	0.48	2.84	0.79	3.09	0.98	2.03	0.19
2017-03-03	2.49	0.45	2.83	0.77	3.08	0.96	2.02	0.1
2017-03-06	2.49	0.48	2.84	0.8	3.1	0.99	2.02	0.12
2017-03-07	2.52	0.49	2.85	0.81	3.11	1.01	2.05	0.13
2017-03-08	2.57	0.56	2.89	0.87	3.15	1.06	2.08	0.18
2017-03-09	2.6	0.6	2.94	0.9	3.19	1.09	2.13	0.24
2017-03-10	2.58	0.57	2.94	0.88	3.16	1.06	2.11	0.21
2017-03-13	2.62	0.61	2.97	0.9	3.2	1.09	2.14	0.28
2017-03-14	2.6	0.61	2.94	0.91	3.17	1.08	2.13	0.25
2017-03-15	2.51	0.5	2.87	0.81	3.11	1	2.02	0.18
2017-03-16	2.53	0.51	2.89	0.82	3.14	1.02	2.05	0.18
2017-03-17	2.5	0.49	2.86	0.82	3.11	1.01	2.03	0.14
2017-03-20	2.47	0.47	2.83	0.79	3.08	1	2	0.14
2017-03-21	2.43	0.45	2.79	0.78	3.04	0.99	1.96	0.16
2017-03-22	2.4	0.43	2.76	0.76	3.02	0.96	1.95	0.16
2017-03-23	2.41	0.46	2.76	0.73	3.02	0.96	1.95	0.2
2017-03-24	2.4	0.42	2.74	0.68	3	0.91	1.93	0.2
2017-03-27	2.38	0.41	2.73	0.67	2.98	0.9	1.93	0.18
2017-03-28	2.42	0.45	2.77	0.71	3.02	0.94	1.97	0.24
2017-03-29	2.39	0.41	2.74	0.72	2.99	0.91	1.93	0.13
2017-03-30	2.42	0.46	2.78	0.77	3.03	0.96	1.96	0.15
2017-03-31	2.4	0.43	2.76	0.74	3.02	0.94	1.93	0.16
2017-04-03	2.35	0.39	2.71	0.67	2.98	0.91	1.88	0.15
2017-04-04	2.36	0.4	2.72	0.72	2.99	0.92	1.88	0.11
2017-04-05	2.34	0.37	2.71	0.69	2.98	0.89	1.85	0.08
2017-04-06	2.34	0.39	2.72	0.67	2.99	0.9	1.87	0.16
2017-04-07	2.38	0.44	2.74	0.71	3	0.94	1.92	0.22
2017-04-10	2.37	0.44	2.72	0.71	2.99	0.94	1.91	0.22
2017-04-11	2.32	0.41	2.67	0.72	2.93	0.91	1.84	0.14
2017-04-12	2.28	0.38	2.65	0.69	2.92	0.89	1.81	0.12
2017-04-13	2.24	0.32	2.62	0.65	2.89	0.86	1.77	0.03
2017-04-14	ND	ND	ND	ND	ND	ND	ND	ND
2017-04-17	2.26	0.38	2.65	0.7	2.92	0.9	1.79	0.1
2017-04-18	2.18	0.33	2.56	0.65	2.84	0.85	1.71	0.06
2017-04-19	2.21	0.36	2.59	0.69	2.87	0.9	1.74	0.08
2017-04-20	2.24	0.39	2.61	0.79	2.89	0.92	1.78	-0.04
2017-04-21	2.24	0.4	2.61	0.78	2.89	0.93	1.77	-0.02
2017-04-24	2.28	0.41	2.65	0.8	2.93	0.94	1.81	0
2017-04-25	2.35	0.44	2.71	0.8	2.99	0.96	1.87	0.02
2017-04-26	2.32	0.42	2.69	0.76	2.97	0.94	1.84	0.01
2017-04-27	2.3	0.39	2.68	0.73	2.96	0.92	1.81	0
2017-04-28	2.29	0.37	2.67	0.71	2.96	0.9	1.81	0
2017-05-01	2.33	0.41	2.71	0.76	3	0.96	1.84	0.04
2017-05-02	2.29	0.41	2.68	0.75	2.97	0.95	1.81	0.04
2017-05-03	2.33	0.46	2.7	0.79	2.97	0.98	1.86	0.1

2017-05-04		2.36	0.5	2.73	0.82	3	1.02	1.88	0.16
2017-05-05		2.36	0.5	2.73	0.84	2.99	1.01	1.89	0.14
2017-05-08		2.39	0.53	2.76	0.86	3.02	1.05	1.91	0.16
2017-05-09		2.42	0.56	2.79	0.87	3.04	1.06	1.94	0.2
2017-05-10		2.41	0.56	2.79	0.88	3.03	1.05	1.94	0.16
2017-05-11		2.39	0.51	2.78	0.83	3.03	1.02	1.93	0.11
2017-05-12		2.33	0.49	2.74	0.82	2.98	1.01	1.85	0.1
2017-05-15		2.34	0.52	2.76	0.86	3	1.05	1.86	0.12
2017-05-16		2.33	0.51	2.74	0.84	2.99	1.04	1.86	0.12
2017-05-17		2.22	0.44	2.65	0.78	2.91	0.97	1.76	0.06
2017-05-18		2.23	0.43	2.64	0.76	2.9	0.96	1.78	0.06
2017-05-19		2.23	0.41	2.63	0.73	2.9	0.92	1.79	0.04
2017-05-22		2.25	0.43	2.64	0.76	2.91	0.95	1.8	0.05
2017-05-23		2.29	0.46	2.68	0.78	2.95	0.96	1.84	0.07
2017-05-24		2.26	0.45	2.65	0.78	2.92	0.97	1.79	0.06
2017-05-25		2.25	0.45	2.65	0.77	2.92	0.97	1.78	0.08
2017-05-26		2.25	0.44	2.65	0.77	2.92	0.96	1.79	0.06
2017-05-29	ND	ND	ND	ND	ND	ND	ND	ND	
2017-05-30		2.21	0.4	2.61	0.73	2.88	0.93	1.76	0.03
2017-05-31		2.21	0.4	2.6	0.73	2.87	0.92	1.75	0.03
2017-06-01		2.21	0.4	2.6	0.73	2.87	0.92	1.76	0.03
2017-06-02		2.15	0.36	2.53	0.68	2.8	0.87	1.71	-0.01
2017-06-05		2.18	0.39	2.56	0.72	2.84	0.92	1.74	0.02
2017-06-06		2.14	0.37	2.53	0.7	2.81	0.91	1.71	0
2017-06-07		2.18	0.4	2.56	0.73	2.84	0.93	1.74	0.05
2017-06-08		2.19	0.41	2.57	0.74	2.85	0.95	1.75	0.06
2017-06-09		2.21	0.43	2.59	0.76	2.86	0.96	1.77	0.09
2017-06-12		2.21	0.46	2.59	0.78	2.86	0.98	1.78	0.11
2017-06-13		2.21	0.46	2.6	0.77	2.87	0.96	1.79	0.12
2017-06-14		2.15	0.44	2.53	0.74	2.79	0.93	1.74	0.15
2017-06-15		2.16	0.49	2.52	0.79	2.78	0.97	1.76	0.2
2017-06-16		2.16	0.49	2.52	0.79	2.78	0.97	1.75	0.19
2017-06-19		2.19	0.52	2.53	0.8	2.79	0.97	1.8	0.24
2017-06-20		2.16	0.5	2.49	0.77	2.74	0.93	1.77	0.23
2017-06-21		2.16	0.5	2.48	0.76	2.73	0.91	1.78	0.24
2017-06-22		2.15	0.46	2.47	0.72	2.72	0.88	1.76	0.19
2017-06-23		2.15	0.45	2.48	0.71	2.71	0.87	1.77	0.18
2017-06-26		2.14	0.43	2.46	0.7	2.7	0.86	1.77	0.16
2017-06-27		2.21	0.5	2.52	0.76	2.75	0.92	1.83	0.21
2017-06-28		2.22	0.49	2.55	0.76	2.77	0.92	1.81	0.16
2017-06-29		2.27	0.55	2.59	0.81	2.82	0.96	1.85	0.23
2017-06-30		2.31	0.58	2.61	0.84	2.84	0.99	1.89	0.26
2017-07-03		2.35	0.6	2.65	0.86	2.86	1	1.93	0.27
2017-07-04	ND	ND	ND	ND	ND	ND	ND	ND	
2017-07-05		2.33	0.58	2.63	0.83	2.85	0.98	1.92	0.27
2017-07-06		2.37	0.61	2.68	0.87	2.9	1.02	1.94	0.28
2017-07-07		2.39	0.66	2.71	0.92	2.93	1.06	1.95	0.32
2017-07-10		2.38	0.66	2.7	0.92	2.93	1.07	1.93	0.33
2017-07-11		2.37	0.62	2.69	0.89	2.92	1.05	1.92	0.31
2017-07-12		2.33	0.57	2.65	0.85	2.89	1.01	1.88	0.25
2017-07-13		2.35	0.58	2.69	0.87	2.92	1.03	1.89	0.25
2017-07-14		2.33	0.57	2.67	0.86	2.91	1.03	1.87	0.25
2017-07-17		2.31	0.54	2.65	0.83	2.89	1	1.86	0.22
2017-07-18		2.27	0.51	2.61	0.8	2.85	0.97	1.82	0.2
2017-07-19		2.27	0.51	2.61	0.8	2.85	0.96	1.83	0.18
2017-07-20		2.27	0.5	2.6	0.8	2.83	0.98	1.82	0.2
2017-07-21		2.24	0.48	2.57	0.78	2.81	0.96	1.81	0.19
2017-07-24		2.26	0.48	2.59	0.78	2.83	0.97	1.83	0.21
2017-07-25		2.33	0.52	2.67	0.83	2.91	1.03	1.9	0.23
2017-07-26		2.29	0.49	2.65	0.8	2.89	1	1.83	0.17
2017-07-27		2.32	0.49	2.68	0.82	2.93	1.02	1.84	0.16
2017-07-28		2.3	0.47	2.65	0.79	2.89	0.99	1.83	0.15
2017-07-31		2.3	0.48	2.66	0.8	2.89	1	1.84	0.17
2017-08-01		2.26	0.47	2.61	0.78	2.86	0.98	1.8	0.18
2017-08-02		2.27	0.48	2.6	0.78	2.85	0.98	1.82	0.19
2017-08-03		2.24	0.46	2.56	0.76	2.81	0.96	1.79	0.17
2017-08-04		2.27	0.47	2.61	0.78	2.84	0.97	1.82	0.17
2017-08-07		2.26	0.46	2.6	0.76	2.84	0.96	1.81	0.16
2017-08-08		2.29	0.46	2.63	0.77	2.86	0.96	1.84	0.15
2017-08-09		2.24	0.42	2.59	0.73	2.82	0.92	1.81	0.11
2017-08-10		2.2	0.4	2.55	0.7	2.79	0.89	1.78	0.1
2017-08-11		2.19	0.4	2.55	0.71	2.79	0.91	1.74	0.1
2017-08-14		2.22	0.45	2.57	0.75	2.81	0.94	1.77	0.18
2017-08-15		2.27	0.49	2.6	0.79	2.84	0.97	1.83	0.2
2017-08-16		2.23	0.45	2.58	0.75	2.81	0.94	1.79	0.17
2017-08-17		2.19	0.42	2.54	0.73	2.78	0.92	1.76	0.15
2017-08-18		2.19	0.43	2.54	0.73	2.78	0.93	1.77	0.16
2017-08-21		2.18	0.43	2.52	0.73	2.77	0.92	1.76	0.17
2017-08-22		2.22	0.45	2.55	0.74	2.79	0.93	1.8	0.19
2017-08-23		2.17	0.42	2.51	0.71	2.75	0.91	1.76	0.18
2017-08-24		2.19	0.44	2.53	0.73	2.77	0.92	1.78	0.18
2017-08-25		2.17	0.42	2.51	0.72	2.75	0.91	1.77	0.2
2017-08-28		2.16	0.41	2.51	0.71	2.76	0.92	1.74	0.18
2017-08-29		2.13	0.39	2.48	0.7	2.74	0.9	1.7	0.16
2017-08-30		2.15	0.39	2.49	0.7	2.75	0.91	1.72	0.15
2017-08-31		2.12	0.36	2.47	0.67	2.73	0.87	1.7	0.12
2017-09-01		2.16	0.37	2.51	0.69	2.77	0.9	1.73	0.1
2017-09-04	ND	ND	ND	ND	ND	ND	ND	ND	
2017-09-05		2.07	0.3	2.43	0.62	2.69	0.83	1.65	0.07
2017-09-06		2.1	0.32	2.46	0.63	2.72	0.85	1.69	0.09
2017-09-07		2.05	0.26	2.4	0.58	2.66	0.8	1.63	0.02
2017-09-08		2.06	0.25	2.41	0.57	2.67	0.79	1.64	0.01
2017-09-11		2.14	0.31	2.49	0.63	2.75	0.84	1.71	0.08
2017-09-12		2.17	0.33	2.52	0.65	2.78	0.85	1.75	0.08
2017-09-13		2.2	0.35	2.53	0.67	2.79	0.87	1.78	0.1
2017-09-14		2.2	0.35	2.52	0.65	2.77	0.85	1.79	0.09
2017-09-15		2.2	0.35	2.52	0.65	2.77	0.84	1.81	0.09
2017-09-18		2.23	0.36	2.56	0.67	2.8	0.86	1.83	0.09
2017-09-19		2.24	0.37	2.57	0.68	2.81	0.87	1.84	0.1

2017-09-20		2.28	0.43	2.59	0.72	2.82	0.9	1.89	0.18
2017-09-21		2.27	0.44	2.57	0.72	2.8	0.9	1.89	0.19
2017-09-22		2.26	0.42	2.57	0.7	2.8	0.88	1.88	0.17
2017-09-25		2.22	0.38	2.53	0.67	2.76	0.85	1.85	0.13
2017-09-26		2.24	0.4	2.54	0.69	2.78	0.87	1.87	0.15
2017-09-27		2.31	0.44	2.62	0.74	2.86	0.92	1.91	0.17
2017-09-28		2.31	0.44	2.63	0.74	2.87	0.92	1.89	0.16
2017-09-29		2.33	0.49	2.63	0.77	2.86	0.94	1.92	0.24
2017-10-02		2.34	0.51	2.64	0.79	2.87	0.95	1.94	0.21
2017-10-03		2.33	0.49	2.63	0.77	2.87	0.94	1.92	0.24
2017-10-04		2.33	0.48	2.64	0.77	2.87	0.94	1.92	0.19
2017-10-05		2.35	0.49	2.65	0.78	2.89	0.95	1.94	0.2
2017-10-06		2.37	0.5	2.68	0.8	2.91	0.97	1.97	0.19
2017-10-09	ND	ND	ND	ND	ND	ND	ND	ND	
2017-10-10		2.35	0.47	2.65	0.77	2.88	0.94	1.95	0.2
2017-10-11		2.35	0.46	2.64	0.75	2.88	0.93	1.95	0.2
2017-10-12		2.33	0.44	2.62	0.73	2.86	0.9	1.95	0.16
2017-10-13		2.28	0.43	2.58	0.7	2.81	0.89	1.91	0.2
2017-10-16		2.3	0.46	2.58	0.7	2.82	0.89	1.95	0.29
2017-10-17		2.3	0.48	2.58	0.73	2.8	0.89	1.97	0.28
2017-10-18		2.34	0.5	2.62	0.76	2.85	0.93	1.99	0.3
2017-10-19		2.33	0.49	2.6	0.72	2.83	0.91	1.98	0.32
2017-10-20		2.39	0.52	2.67	0.79	2.89	0.95	2.03	0.27
2017-10-23		2.38	0.52	2.66	0.75	2.89	0.95	2.01	0.32
2017-10-24		2.42	0.55	2.7	0.81	2.92	0.97	2.05	0.32
2017-10-25		2.44	0.56	2.72	0.83	2.95	0.99	2.06	0.32
2017-10-26		2.46	0.57	2.74	0.84	2.96	1	2.07	0.31
2017-10-27		2.42	0.54	2.71	0.81	2.93	0.97	2.03	0.27
2017-10-30		2.37	0.5	2.66	0.77	2.88	0.93	2	0.23
2017-10-31		2.38	0.5	2.66	0.77	2.88	0.92	2.01	0.22
2017-11-01		2.37	0.49	2.63	0.72	2.85	0.91	2.01	0.3
2017-11-02		2.35	0.48	2.61	0.74	2.83	0.89	2	0.21
2017-11-03		2.34	0.48	2.59	0.73	2.82	0.88	1.99	0.25
2017-11-06		2.32	0.46	2.58	0.71	2.8	0.87	1.99	0.22
2017-11-07		2.32	0.44	2.56	0.69	2.77	0.84	1.99	0.19
2017-11-08		2.32	0.45	2.57	0.69	2.79	0.84	2.01	0.24
2017-11-09		2.33	0.46	2.59	0.71	2.81	0.86	2.01	0.21
2017-11-10		2.4	0.52	2.67	0.77	2.88	0.92	2.06	0.28
2017-11-13		2.4	0.52	2.67	0.76	2.87	0.91	2.08	0.29
2017-11-14		2.38	0.51	2.64	0.75	2.84	0.89	2.06	0.27
2017-11-15		2.33	0.48	2.58	0.71	2.77	0.85	2.04	0.26
2017-11-16		2.37	0.53	2.62	0.74	2.81	0.87	2.07	0.28
2017-11-17		2.35	0.49	2.59	0.71	2.78	0.85	2.06	0.31
2017-11-20		2.37	0.52	2.6	0.72	2.78	0.85	2.09	0.35
2017-11-21		2.36	0.52	2.58	0.72	2.76	0.84	2.11	0.36
2017-11-22		2.32	0.48	2.57	0.69	2.75	0.82	2.05	0.3
2017-11-23	ND	ND	ND	ND	ND	ND	ND	ND	
2017-11-24		2.34	0.5	2.58	0.71	2.76	0.85	2.07	0.36
2017-11-27		2.32	0.49	2.57	0.69	2.76	0.84	2.06	0.37
2017-11-28		2.34	0.5	2.58	0.7	2.77	0.85	2.07	0.38
2017-11-29		2.37	0.53	2.62	0.75	2.81	0.88	2.09	0.4
2017-11-30		2.42	0.56	2.65	0.76	2.83	0.88	2.14	0.41
2017-12-01		2.37	0.51	2.58	0.69	2.76	0.81	2.13	0.41
2017-12-04		2.37	0.5	2.58	0.68	2.77	0.8	2.15	0.39
2017-12-05		2.36	0.5	2.55	0.65	2.73	0.78	2.15	0.46
2017-12-06		2.33	0.47	2.53	0.65	2.71	0.77	2.11	0.37
2017-12-07		2.37	0.5	2.58	0.69	2.76	0.81	2.14	0.4
2017-12-08		2.38	0.5	2.59	0.68	2.77	0.81	2.14	0.43
2017-12-11		2.39	0.51	2.59	0.7	2.77	0.82	2.16	0.4
2017-12-12		2.4	0.51	2.6	0.69	2.79	0.81	2.18	0.4
2017-12-13		2.36	0.48	2.56	0.67	2.74	0.79	2.12	0.38
2017-12-14		2.35	0.48	2.53	0.65	2.71	0.77	2.14	0.38
2017-12-15		2.35	0.47	2.52	0.63	2.68	0.75	2.16	0.39
2017-12-18		2.39	0.5	2.57	0.66	2.74	0.79	2.17	0.46
2017-12-19		2.46	0.55	2.66	0.71	2.82	0.84	2.23	0.49
2017-12-20		2.49	0.57	2.71	0.75	2.88	0.89	2.24	0.5
2017-12-21		2.48	0.55	2.68	0.73	2.84	0.85	2.26	0.42
2017-12-22		2.48	0.54	2.68	0.72	2.83	0.84	2.26	0.44
2017-12-25	ND	ND	ND	ND	ND	ND	ND	ND	
2017-12-26		2.47	0.53	2.66	0.7	2.82	0.83	2.25	0.49
2017-12-27		2.42	0.48	2.59	0.64	2.75	0.76	2.22	0.4
2017-12-28		2.43	0.47	2.6	0.64	2.75	0.75	2.23	0.37
2017-12-29		2.4	0.44	2.58	0.61	2.74	0.73	2.2	0.34
2018-01-01	ND	ND	ND	ND	ND	ND	ND	ND	
2018-01-02		2.46	0.46	2.64	0.64	2.81	0.77	2.25	0.35
2018-01-03		2.44	0.46	2.62	0.63	2.78	0.76	2.25	0.38
2018-01-04		2.46	0.45	2.62	0.62	2.79	0.75	2.27	0.35
2018-01-05		2.47	0.46	2.64	0.63	2.81	0.76	2.29	0.34
2018-01-08		2.49	0.47	2.65	0.65	2.81	0.77	2.29	0.38
2018-01-09		2.55	0.52	2.72	0.7	2.88	0.82	2.33	0.38
2018-01-10		2.55	0.52	2.73	0.7	2.88	0.82	2.32	0.38
2018-01-11		2.54	0.54	2.72	0.71	2.91	0.83	2.32	0.43
2018-01-12		2.55	0.54	2.71	0.7	2.85	0.81	2.35	0.43
2018-01-15	ND	ND	ND	ND	ND	ND	ND	ND	
2018-01-16		2.54	0.51	2.69	0.67	2.83	0.78	2.36	0.42
2018-01-17		2.57	0.53	2.71	0.67	2.84	0.79	2.39	0.49
2018-01-18		2.62	0.57	2.77	0.72	2.9	0.81	2.43	0.44
2018-01-19		2.64	0.58	2.78	0.72	2.91	0.81	2.45	0.45
2018-01-22		2.66	0.6	2.79	0.74	2.93	0.83	2.46	0.46
2018-01-23		2.63	0.57	2.77	0.71	2.9	0.81	2.43	0.51
2018-01-24		2.65	0.58	2.8	0.73	2.93	0.82	2.43	0.47
2018-01-25		2.63	0.56	2.76	0.69	2.89	0.79	2.41	0.5
2018-01-26		2.66	0.57	2.79	0.7	2.91	0.8	2.47	0.54
2018-01-29		2.7	0.61	2.82	0.73	2.94	0.81	2.49	0.57
2018-01-30		2.73	0.63	2.86	0.76	2.98	0.84	2.51	0.54
2018-01-31		2.72	0.61	2.83	0.72	2.95	0.8	2.52	0.54
2018-02-01		2.78	0.67	2.9	0.78	3.01	0.86	2.56	0.63
2018-02-02		2.84	0.7	2.97	0.82	3.08	0.9	2.58	0.65
2018-02-05		2.77	0.67	2.92	0.81	3.04	0.89	2.5	0.55

2018-02-06		2.79	0.69	2.94	0.82	3.06	0.91	2.52	0.64
2018-02-07		2.84	0.74	3.01	0.86	3.12	0.96	2.57	0.67
2018-02-08		2.85	0.76	3.03	0.89	3.14	0.99	2.57	0.68
2018-02-09		2.83	0.78	3.02	0.91	3.14	1.01	2.52	0.69
2018-02-12		2.86	0.79	3.02	0.92	3.14	1.01	2.56	0.72
2018-02-13		2.83	0.78	2.99	0.91	3.11	0.99	2.54	0.66
2018-02-14		2.91	0.82	3.07	0.94	3.18	1.02	2.65	0.74
2018-02-15		2.9	0.79	3.04	0.93	3.15	1.02	2.65	0.65
2018-02-16		2.87	0.78	3.02	0.92	3.13	1.01	2.63	0.63
2018-02-19	ND	ND	ND	ND	ND	ND	ND	ND	
2018-02-20		2.88	0.78	3.04	0.92	3.15	1.01	2.65	0.61
2018-02-21		2.94	0.82	3.11	0.97	3.22	1.06	2.69	0.63
2018-02-22		2.92	0.81	3.09	0.96	3.21	1.06	2.66	0.6
2018-02-23		2.88	0.76	3.04	0.92	3.16	1.03	2.62	0.58
2018-02-26		2.86	0.73	3.03	0.9	3.15	1.01	2.6	0.53
2018-02-27		2.9	0.77	3.06	0.92	3.17	1.02	2.67	0.58
2018-02-28		2.87	0.75	3.02	0.9	3.13	0.99	2.65	0.61
2018-03-01		2.81	0.71	2.97	0.86	3.09	0.96	2.58	0.55
2018-03-02		2.86	0.74	3.02	0.89	3.14	0.98	2.63	0.6
2018-03-05		2.88	0.75	3.04	0.91	3.16	1.01	2.65	0.6
2018-03-06		2.88	0.76	3.03	0.91	3.14	1.01	2.65	0.55
2018-03-07		2.89	0.76	3.04	0.93	3.15	1.03	2.65	0.55
2018-03-08		2.86	0.75	3.01	0.9	3.13	1	2.63	0.55
2018-03-09		2.9	0.78	3.04	0.92	3.16	1.03	2.65	0.69
2018-03-12		2.87	0.77	3	0.92	3.13	1.01	2.64	0.62
2018-03-13		2.84	0.75	2.98	0.9	3.1	1	2.62	0.57
2018-03-14		2.81	0.74	2.94	0.88	3.05	0.97	2.61	0.57
2018-03-15		2.82	0.74	2.94	0.88	3.05	0.97	2.62	0.55
2018-03-16		2.85	0.77	2.96	0.91	3.08	1	2.65	0.6
2018-03-19		2.85	0.77	2.97	0.91	3.09	1	2.65	0.61
2018-03-20		2.89	0.81	3.01	0.94	3.12	1.03	2.69	0.64
2018-03-21		2.89	0.8	3.01	0.92	3.12	1.03	2.69	0.73
2018-03-22		2.83	0.75	2.94	0.89	3.06	0.97	2.63	0.6
2018-03-23		2.82	0.75	2.94	0.89	3.06	0.98	2.61	0.6
2018-03-26		2.85	0.77	2.96	0.91	3.08	0.99	2.64	0.63
2018-03-27		2.78	0.71	2.9	0.84	3.03	0.95	2.58	0.64
2018-03-28		2.77	0.72	2.89	0.84	3.01	0.94	2.59	0.68
2018-03-29		2.74	0.69	2.85	0.81	2.97	0.9	2.56	0.64
2018-03-30	ND	ND	ND	ND	ND	ND	ND	ND	
2018-04-02		2.73	0.68	2.85	0.81	2.97	0.9	2.55	0.56
2018-04-03		2.79	0.71	2.9	0.84	3.02	0.92	2.6	0.61
2018-04-04		2.79	0.71	2.91	0.85	3.03	0.93	2.61	0.57
2018-04-05		2.83	0.75	2.95	0.87	3.07	0.97	2.64	0.71
2018-04-06		2.77	0.7	2.89	0.83	3.01	0.92	2.58	0.57
2018-04-09		2.78	0.71	2.89	0.83	3.02	0.92	2.6	0.58
2018-04-10		2.8	0.72	2.89	0.84	3.02	0.92	2.62	0.62
2018-04-11		2.79	0.68	2.87	0.8	2.99	0.88	2.62	0.56
2018-04-12		2.83	0.7	2.92	0.82	3.05	0.9	2.67	0.62
2018-04-13		2.82	0.69	2.91	0.79	3.03	0.88	2.67	0.66
2018-04-16		2.83	0.71	2.91	0.81	3.03	0.89	2.69	0.61
2018-04-17		2.82	0.68	2.89	0.78	3	0.85	2.68	0.67
2018-04-18		2.87	0.71	2.95	0.81	3.06	0.89	2.73	0.69
2018-04-19		2.92	0.75	3.01	0.84	3.11	0.92	2.77	0.65
2018-04-20		2.96	0.79	3.04	0.88	3.14	0.96	2.8	0.7
2018-04-23		2.98	0.8	3.05	0.89	3.15	0.97	2.83	0.72
2018-04-24		3	0.83	3.08	0.93	3.18	1.01	2.83	0.73
2018-04-25		3.03	0.86	3.12	0.95	3.21	1.03	2.84	0.75
2018-04-26		3	0.82	3.08	0.92	3.18	0.99	2.82	0.72
2018-04-27		2.96	0.79	3.03	0.87	3.13	0.93	2.8	0.71
2018-04-30		2.95	0.78	3.01	0.86	3.11	0.91	2.79	0.69
2018-05-01		2.97	0.81	3.03	0.89	3.13	0.94	2.82	0.73
2018-05-02		2.97	0.8	3.04	0.89	3.14	0.95	2.8	0.71
2018-05-03		2.94	0.78	3.02	0.88	3.12	0.94	2.78	0.69
2018-05-04		2.95	0.79	3.02	0.87	3.12	0.94	2.78	0.69
2018-05-07		2.95	0.78	3.02	0.88	3.12	0.94	2.78	0.67
2018-05-08		2.97	0.81	3.04	0.89	3.13	0.96	2.81	0.71
2018-05-09		3	0.82	3.07	0.91	3.16	0.97	2.84	0.71
2018-05-10		2.97	0.8	3.04	0.88	3.12	0.94	2.83	0.71
2018-05-11		2.97	0.82	3.03	0.88	3.1	0.94	2.84	0.71
2018-05-14		3	0.85	3.06	0.92	3.13	0.97	2.85	0.73
2018-05-15		3.08	0.9	3.14	0.97	3.2	1.02	2.92	0.77
2018-05-16		3.09	0.92	3.16	0.98	3.21	1.02	2.94	0.78
2018-05-17		3.11	0.95	3.19	1.02	3.25	1.07	2.94	0.78
2018-05-18		3.06	0.91	3.14	0.99	3.2	1.04	2.9	0.76

Current-Dollar and "Real" Gross Domestic Product 4/27/18

Annual

	GDP in billions of current dollars	GDP in billions of chained 2009 dollars
1929	104.6	1,056.60
1930	92.2	966.7
1931	77.4	904.8
1932	59.5	788.2
1933	57.2	778.3
1934	66.8	862.2
1935	74.3	939
1936	84.9	1,060.50
1937	93	1,114.60
1938	87.4	1,077.70
1939	93.5	1,163.60
1940	102.9	1,266.10
1941	129.4	1,490.30
1942	166	1,771.80
1943	203.1	2,073.70
1944	224.6	2,239.40
1945	228.2	2,217.80
1946	227.8	1,960.90
1947	249.9	1,939.40
1948	274.8	2,020.00
1949	272.8	2,008.90
1950	300.2	2,184.00
1951	347.3	2,360.00
1952	367.7	2,456.10
1953	389.7	2,571.40
1954	391.1	2,556.90
1955	426.2	2,739.00
1956	450.1	2,797.40
1957	474.9	2,856.30
1958	482	2,835.30
1959	522.5	3,031.00
1960	543.3	3,108.70
1961	563.3	3,188.10
1962	605.1	3,383.10
1963	638.6	3,530.40
1964	685.8	3,734.00
1965	743.7	3,976.70
1966	815	4,238.90
1967	861.7	4,355.20
1968	942.5	4,569.00
1969	1,019.90	4,712.50
1970	1,075.90	4,722.00
1971	1,167.80	4,877.60
1972	1,282.40	5,134.30
1973	1,428.50	5,424.10
1974	1,548.80	5,396.00
1975	1,688.90	5,385.40
1976	1,877.60	5,675.40
1977	2,086.00	5,937.00
1978	2,356.60	6,267.20
1979	2,632.10	6,466.20
1980	2,862.50	6,450.40
1981	3,211.00	6,617.70
1982	3,345.00	6,491.30
1983	3,638.10	6,792.00
1984	4,040.70	7,285.00
1985	4,346.70	7,593.80
1986	4,590.20	7,860.50

Quarterly
(Seasonally adjusted annual rates)

		GDP in billions of current dollars	GDP in billions of chained 2009 dollars
	1947Q1	243.1	1,934.50
-8.51%	1947Q2	246.3	1,932.30
-6.40%	1947Q3	250.1	1,930.30
-12.89%	1947Q4	260.3	1,960.70
-1.26%	1948Q1	266.2	1,989.50
10.78%	1948Q2	272.9	2,021.90
8.91%	1948Q3	279.5	2,033.20
12.94%	1948Q4	280.7	2,035.30
5.10%	1949Q1	275.4	2,007.50
-3.31%	1949Q2	271.7	2,000.80
7.97%	1949Q3	273.3	2,022.80
8.81%	1949Q4	271	2,004.70
17.71%	1950Q1	281.2	2,084.60
18.89%	1950Q2	290.7	2,147.60
17.04%	1950Q3	308.5	2,230.40
7.99%	1950Q4	320.3	2,273.40
-0.96%	1951Q1	336.4	2,304.50
-11.58%	1951Q2	344.5	2,344.50
-1.10%	1951Q3	351.8	2,392.80
4.16%	1951Q4	356.6	2,398.10
-0.55%	1952Q1	360.2	2,423.50
8.72%	1952Q2	361.4	2,428.50
8.06%	1952Q3	368.1	2,446.10
4.07%	1952Q4	381.2	2,526.40
4.69%	1953Q1	388.5	2,573.40
-0.56%	1953Q2	392.3	2,593.50
7.12%	1953Q3	391.7	2,578.90
2.13%	1953Q4	386.5	2,539.80
2.11%	1954Q1	385.9	2,528.00
-0.74%	1954Q2	386.7	2,530.70
6.90%	1954Q3	391.6	2,559.40
2.56%	1954Q4	400.3	2,609.30
2.55%	1955Q1	413.8	2,683.80
6.12%	1955Q2	422.2	2,727.50
4.35%	1955Q3	430.9	2,764.10
5.77%	1955Q4	437.8	2,780.80
6.50%	1956Q1	440.5	2,770.00
6.59%	1956Q2	446.8	2,792.90
2.74%	1956Q3	452	2,790.60
4.91%	1956Q4	461.3	2,836.20
3.14%	1957Q1	470.6	2,854.50
0.20%	1957Q2	472.8	2,848.20
3.30%	1957Q3	480.3	2,875.90
5.26%	1957Q4	475.7	2,846.40
5.64%	1958Q1	468.4	2,772.70
-0.52%	1958Q2	472.8	2,790.90
-0.20%	1958Q3	486.7	2,855.50
5.38%	1958Q4	500.4	2,922.30
4.61%	1959Q1	511.1	2,976.60
5.56%	1959Q2	524.2	3,049.00
3.18%	1959Q3	525.2	3,043.10
-0.24%	1959Q4	529.3	3,055.10
2.59%	1960Q1	543.3	3,123.20
-1.91%	1960Q2	542.7	3,111.30
4.63%	1960Q3	546	3,119.10
7.26%	1960Q4	541.1	3,081.30
4.24%	1961Q1	545.9	3,102.30
3.51%	1961Q2	557.4	3,159.90

1987	4,870.20	8,132.60	3.46%	1961Q3	568.2	3,212.60
1988	5,252.60	8,474.50	4.20%	1961Q4	581.6	3,277.70
1989	5,657.70	8,786.40	3.68%	1962Q1	595.2	3,336.80
1990	5,979.60	8,955.00	1.92%	1962Q2	602.6	3,372.70
1991	6,174.00	8,948.40	-0.07%	1962Q3	609.6	3,404.80
1992	6,539.30	9,266.60	3.56%	1962Q4	613.1	3,418.00
1993	6,878.70	9,521.00	2.75%	1963Q1	622.7	3,456.10
1994	7,308.80	9,905.40	4.04%	1963Q2	631.8	3,501.10
1995	7,664.10	10,174.80	2.72%	1963Q3	645	3,569.50
1996	8,100.20	10,561.00	3.80%	1963Q4	654.8	3,595.00
1997	8,608.50	11,034.90	4.49%	1964Q1	671.1	3,672.70
1998	9,089.20	11,525.90	4.45%	1964Q2	680.8	3,716.40
1999	9,660.60	12,065.90	4.69%	1964Q3	692.8	3,766.90
2000	10,284.80	12,559.70	4.09%	1964Q4	698.4	3,780.20
2001	10,621.80	12,682.20	0.98%	1965Q1	719.2	3,873.50
2002	10,977.50	12,908.80	1.79%	1965Q2	732.4	3,926.40
2003	11,510.70	13,271.10	2.81%	1965Q3	750.2	4,006.20
2004	12,274.90	13,773.50	3.79%	1965Q4	773.1	4,100.60
2005	13,093.70	14,234.20	3.34%	1966Q1	797.3	4,201.90
2006	13,855.90	14,613.80	2.67%	1966Q2	807.2	4,219.10
2007	14,477.60	14,873.70	1.78%	1966Q3	820.8	4,249.20
2008	14,718.60	14,830.40	-0.29%	1966Q4	834.9	4,285.60
2009	14,418.70	14,418.70	-2.78%	1967Q1	846	4,324.90
2010	14,964.40	14,783.80	2.53%	1967Q2	851.1	4,328.70
2011	15,517.90	15,020.60	1.60%	1967Q3	866.6	4,366.10
2012	16,155.30	15,354.60	2.22%	1967Q4	883.2	4,401.20
2013	16,691.50	15,612.20	1.68%	1968Q1	911.1	4,490.60
2014	17,427.60	16,013.30	2.57%	1968Q2	936.3	4,566.40
2015	18,120.70	16,471.50	2.86%	1968Q3	952.3	4,599.30
2016	18,624.50	16,716.20	1.49%	1968Q4	970.1	4,619.80
2017	19390.60	17096.20	2.27%	1969Q1	995.4	4,691.60
				1969Q2	1,011.40	4,706.70
	6.11%	3.21%	3.33%	1969Q3	1,032.00	4,736.10
				1969Q4	1,040.70	4,715.50
				1970Q1	1,053.50	4,707.10
				1970Q2	1,070.10	4,715.40
				1970Q3	1,088.50	4,757.20
				1970Q4	1,091.50	4,708.30
				1971Q1	1,137.80	4,834.30
				1971Q2	1,159.40	4,861.90
				1971Q3	1,180.30	4,900.00
				1971Q4	1,193.60	4,914.30
				1972Q1	1,233.80	5,002.40
				1972Q2	1,270.10	5,118.30
				1972Q3	1,293.80	5,165.40
				1972Q4	1,332.00	5,251.20
				1973Q1	1,380.70	5,380.50
				1973Q2	1,417.60	5,441.50
				1973Q3	1,436.80	5,411.90
				1973Q4	1,479.10	5,462.40
				1974Q1	1,494.70	5,417.00
				1974Q2	1,534.20	5,431.30
				1974Q3	1,563.40	5,378.70
				1974Q4	1,603.00	5,357.20
				1975Q1	1,619.60	5,292.40
				1975Q2	1,656.40	5,333.20
				1975Q3	1,713.80	5,421.40
				1975Q4	1,765.90	5,494.40
				1976Q1	1,824.50	5,618.50
				1976Q2	1,856.90	5,661.00
				1976Q3	1,890.50	5,689.80
				1976Q4	1,938.40	5,732.50
				1977Q1	1,992.50	5,799.20
				1977Q2	2,060.20	5,913.00
				1977Q3	2,122.40	6,017.60
				1977Q4	2,168.70	6,018.20
				1978Q1	2,208.70	6,039.20
				1978Q2	2,336.60	6,274.00
				1978Q3	2,398.90	6,335.30
				1978Q4	2,482.20	6,420.30
				1979Q1	2,531.60	6,433.00
				1979Q2	2,595.90	6,440.80

1979Q3	2,670.40	6,487.10
1979Q4	2,730.70	6,503.90
1980Q1	2,796.50	6,524.90
1980Q2	2,799.90	6,392.60
1980Q3	2,860.00	6,382.90
1980Q4	2,993.50	6,501.20
1981Q1	3,131.80	6,635.70
1981Q2	3,167.30	6,587.30
1981Q3	3,261.20	6,662.90
1981Q4	3,283.50	6,585.10
1982Q1	3,273.80	6,475.00
1982Q2	3,331.30	6,510.20
1982Q3	3,367.10	6,486.80
1982Q4	3,407.80	6,493.10
1983Q1	3,480.30	6,578.20
1983Q2	3,583.80	6,728.30
1983Q3	3,692.30	6,860.00
1983Q4	3,796.10	7,001.50
1984Q1	3,912.80	7,140.60
1984Q2	4,015.00	7,266.00
1984Q3	4,087.40	7,337.50
1984Q4	4,147.60	7,396.00
1985Q1	4,237.00	7,469.50
1985Q2	4,302.30	7,537.90
1985Q3	4,394.60	7,655.20
1985Q4	4,453.10	7,712.60
1986Q1	4,516.30	7,784.10
1986Q2	4,555.20	7,819.80
1986Q3	4,619.60	7,898.60
1986Q4	4,669.40	7,939.50
1987Q1	4,736.20	7,995.00
1987Q2	4,821.50	8,084.70
1987Q3	4,900.50	8,158.00
1987Q4	5,022.70	8,292.70
1988Q1	5,090.60	8,339.30
1988Q2	5,207.70	8,449.50
1988Q3	5,299.50	8,498.30
1988Q4	5,412.70	8,610.90
1989Q1	5,527.40	8,697.70
1989Q2	5,628.40	8,766.10
1989Q3	5,711.60	8,831.50
1989Q4	5,763.40	8,850.20
1990Q1	5,890.80	8,947.10
1990Q2	5,974.70	8,981.70
1990Q3	6,029.50	8,983.90
1990Q4	6,023.30	8,907.40
1991Q1	6,054.90	8,865.60
1991Q2	6,143.60	8,934.40
1991Q3	6,218.40	8,977.30
1991Q4	6,279.30	9,016.40
1992Q1	6,380.80	9,123.00
1992Q2	6,492.30	9,223.50
1992Q3	6,586.50	9,313.20
1992Q4	6,697.60	9,406.50
1993Q1	6,748.20	9,424.10
1993Q2	6,829.60	9,480.10
1993Q3	6,904.20	9,526.30
1993Q4	7,032.80	9,653.50
1994Q1	7,136.30	9,748.20
1994Q2	7,269.80	9,881.40
1994Q3	7,352.30	9,939.70
1994Q4	7,476.70	10,052.50
1995Q1	7,545.30	10,086.90
1995Q2	7,604.90	10,122.10
1995Q3	7,706.50	10,208.80
1995Q4	7,799.50	10,281.20
1996Q1	7,893.10	10,348.70
1996Q2	8,061.50	10,529.40
1996Q3	8,159.00	10,626.80
1996Q4	8,287.10	10,739.10
1997Q1	8,402.10	10,820.90
1997Q2	8,551.90	10,984.20

1997Q3	8,691.80	11,124.00
1997Q4	8,788.30	11,210.30
1998Q1	8,889.70	11,321.20
1998Q2	8,994.70	11,431.00
1998Q3	9,146.50	11,580.60
1998Q4	9,325.70	11,770.70
1999Q1	9,447.10	11,864.70
1999Q2	9,557.00	11,962.50
1999Q3	9,712.30	12,113.10
1999Q4	9,926.10	12,323.30
2000Q1	10,031.00	12,359.10
2000Q2	10,278.30	12,592.50
2000Q3	10,357.40	12,607.70
2000Q4	10,472.30	12,679.30
2001Q1	10,508.10	12,643.30
2001Q2	10,638.40	12,710.30
2001Q3	10,639.50	12,670.10
2001Q4	10,701.30	12,705.30
2002Q1	10,834.40	12,822.30
2002Q2	10,934.80	12,893.00
2002Q3	11,037.10	12,955.80
2002Q4	11,103.80	12,964.00
2003Q1	11,230.10	13,031.20
2003Q2	11,370.70	13,152.10
2003Q3	11,625.10	13,372.40
2003Q4	11,816.80	13,528.70
2004Q1	11,988.40	13,606.50
2004Q2	12,181.40	13,706.20
2004Q3	12,367.70	13,830.80
2004Q4	12,562.20	13,950.40
2005Q1	12,813.70	14,099.10
2005Q2	12,974.10	14,172.70
2005Q3	13,205.40	14,291.80
2005Q4	13,381.60	14,373.40
2006Q1	13,648.90	14,546.10
2006Q2	13,799.80	14,589.60
2006Q3	13,908.50	14,602.60
2006Q4	14,066.40	14,716.90
2007Q1	14,233.20	14,726.00
2007Q2	14,422.30	14,838.70
2007Q3	14,569.70	14,938.50
2007Q4	14,685.30	14,991.80
2008Q1	14,668.40	14,889.50
2008Q2	14,813.00	14,963.40
2008Q3	14,843.00	14,891.60
2008Q4	14,549.90	14,577.00
2009Q1	14,383.90	14,375.00
2009Q2	14,340.40	14,355.60
2009Q3	14,384.10	14,402.50
2009Q4	14,566.50	14,541.90
2010Q1	14,681.10	14,604.80
2010Q2	14,888.60	14,745.90
2010Q3	15,057.70	14,845.50
2010Q4	15,230.20	14,939.00
2011Q1	15,238.40	14,881.30
2011Q2	15,460.90	14,989.60
2011Q3	15,587.10	15,021.10
2011Q4	15,785.30	15,190.30
2012Q1	15,973.90	15,291.00
2012Q2	16,121.90	15,362.40
2012Q3	16,227.90	15,380.80
2012Q4	16,297.30	15,384.30
2013Q1	16,475.40	15,491.90
2013Q2	16,541.40	15,521.60
2013Q3	16,749.30	15,641.30
2013Q4	16,999.90	15,793.90
2014Q1	17,031.30	15,757.60
2014Q2	17,320.90	15,935.80
2014Q3	17,622.30	16,139.50
2014Q4	17,735.90	16,220.20
2015Q1	17,874.70	16,350.00
2015Q2	18,093.20	16,460.90

2015Q3	18,227.70	16,527.60
2015Q4	18,287.20	16,547.60
2016Q1	18,325.20	16,571.60
2016Q2	18,538.00	16,663.50
2016Q3	18,729.10	16,778.10
2016Q4	18,905.50	16,851.40
2017Q1	19,057.70	16,903.20
2017Q2	19,250.00	17,031.10
2017Q3	19,500.60	17,163.90
2017Q4	19754.10	17286.50
2018Q1	19965.3	17385.8

ALE US Equity

Date	TRAIL_12M_DILUTE EQY_DPS		Payout %
12/31/1990	3.555	2.79	0.78481013
12/31/1991	3.69	2.85	0.77235772
12/31/1992	3.705	2.91	0.7854251
12/31/1993	3.3	2.97	0.9
12/30/1994	3.09	3.03	0.98058252
12/29/1995	3.24	3.06	0.94444444
12/31/1996	3.42	3.06	0.89473684
12/31/1997	3.705	3.06	0.82591093
12/31/1998	4.035	3.06	0.75836431
12/31/1999	2.91	3.21	1.10309278
12/29/2000	6.33	3.21	0.507109
12/31/2001	5.43	3.21	0.59116022
12/31/2002	5.04	3.3	0.6547619
12/31/2003	8.52	3.39	0.39788732
12/31/2004	3.67	2.8425	0.77452316
12/30/2005	0.48	1.245	2.59375
12/29/2006	2.74	1.45	0.52919708
12/31/2007	3.08	1.64	0.53246753
12/31/2008	2.82	1.72	0.60992908
12/31/2009	1.89	1.76	0.93121693
12/31/2010	2.19	1.76	0.80365297
12/30/2011	2.65	1.78	0.67169811
12/31/2012	2.58	1.84	0.71317829
12/31/2013	2.63	1.9	0.72243346
12/31/2014	2.9	1.96	0.67586207
12/31/2015	2.92	2.02	0.69178082
12/30/2016	3.14	2.08	0.66242038
12/31/2017	3.38	2.14	0.63313609
		Median	0.74039889

Electric Universe Average Payout Ratio

LNT US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	1.115	0.87	0.78026906
12/31/1991	1.215	0.9	0.74074074
12/31/1992	1.05	0.93	0.88571429
12/31/1993	1.055	0.95	0.90047393
12/30/1994	1.065	0.96	0.90140845
12/29/1995	0.95	0.97	1.02105263
12/31/1996	1.17	0.985	0.84188034
12/31/1997	0.9485	1	1.05429626
12/31/1998	0.6285	1	1.5910899
12/31/1999	1.255	1	0.79681275
12/29/2000	2.515	1	0.39761431
12/31/2001	1.07	1	0.93457944
12/31/2002	0.59	1	1.69491525
12/31/2003	0.905	0.5	0.55248619
12/31/2004	0.64	0.5063	0.79109375
12/30/2005	-0.035	0.525	-15
12/29/2006	1.345	0.575	0.42750929
12/31/2007	1.89	0.635	0.33597884
12/31/2008	1.305	0.7	0.53639847
12/31/2009	0.505	0.75	1.48514851
12/31/2010	1.3	0.79	0.60769231
12/30/2011	1.37	0.85	0.62043796
12/31/2012	1.445	0.9	0.62283737
12/31/2013	1.615	0.94	0.58204334
12/31/2014	1.73	1.02	0.58959538
12/31/2015	1.68	1.1	0.6547619
12/30/2016	1.64	1.175	0.71646341
12/31/2017	1.9476	1.26	0.64695009
		Median	0.72860208

65.57%

AEE US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/29/1995	2.72	#N/A N/A	
12/31/1996	2.71	#N/A N/A	
12/31/1997	2.439	0	
12/31/1998	2.817	2.54	0.90166844
12/31/1999	2.81	2.54	0.90391459
12/29/2000	3.33	2.54	0.76276276
12/31/2001	3.4	2.54	0.74705882
12/31/2002	2.6	2.54	0.97692308
12/31/2003	3.25	2.54	0.78153846
12/31/2004	2.84	2.54	0.8943662
12/30/2005	3.02	2.54	0.8410596
12/29/2006	2.66	2.54	0.95488722
12/31/2007	2.98	2.54	0.85234899
12/31/2008	2.88	2.54	0.88194444
12/31/2009	2.78	1.54	0.55395683
12/31/2010	0.58	1.54	2.65517241
12/30/2011	2.15	1.555	0.72325581
12/31/2012	-4.01	1.6	-0.39900249
12/31/2013	1.18	1.6	1.3559322
12/31/2014	2.4	1.61	0.67083333
12/31/2015	2.59	1.655	0.63899614
12/30/2016	2.68	1.715	0.63992537
12/31/2017	2.14	1.778	0.83084112

	Median	0.83595036

AEP US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	2.65	2.4	0.90566038
12/31/1991	2.7	2.4	0.88888889
12/31/1992	2.54	2.4	0.94488189
12/31/1993	1.92	2.4	1.25
12/30/1994	2.71	2.4	0.88560886
12/29/1995	2.85	2.4	0.84210526
12/31/1996	3.14	2.4	0.76433121
12/31/1997	2.703	2.4	0.88790233
12/31/1998	2.811	2.4	0.85378869
12/31/1999	3.03	2.4	0.79207921
12/29/2000	0.83	2.4	2.89156627
12/31/2001	3.01	2.4	0.79734219
12/31/2002	-1.57	2.4	-1.5286624
12/31/2003	0.29	1.65	5.68965517
12/31/2004	2.75	1.4	0.50909091
12/30/2005	2.08	1.42	0.68269231
12/29/2006	2.53	1.5	0.59288538
12/31/2007	2.72	1.58	0.58088235
12/31/2008	3.42	1.64	0.47953216
12/31/2009	2.96	1.64	0.55405405
12/31/2010	2.53	1.71	0.67588933
12/30/2011	4.02	1.85	0.460199
12/31/2012	2.6	1.88	0.72307692
12/31/2013	3.04	1.95	0.64144737
12/31/2014	3.34	2.03	0.60778443
12/31/2015	4.17	2.15	0.51558753
12/30/2016	1.24	2.27	1.83064516
12/31/2017	3.88	2.39	0.61597938
		Median	0.74370407

AGR US Equity

Date	TRAIL_12M_	EQY_DPS	Payout %
12/31/1990	2.48	2.06	0.83064516
12/31/1991	2.36	2.1	0.88983051
12/31/1992	2.4	2.14	0.89166667
12/31/1993	2.08	2.18	1.04807692
12/30/1994	2.37	2	0.84388186
12/29/1995	2.49	1.4	0.562249
12/31/1996	2.37	1.4	0.5907173
12/31/1997	2.57	1.4	0.54474708
12/31/1998	3.02	1.55	0.51324503
12/31/1999	1.88	0.84	0.44680851
12/29/2000	2.06	0.88	0.42718447
12/31/2001	1.61	0.92	0.57142857
12/31/2002	1.44	0.96	0.66666667
12/31/2003	1.44	1	0.69444444
12/31/2004	1.56	1.055	0.67628205
12/30/2005	1.74	1.115	0.6408046
12/29/2006	1.76	1.17	0.66477273
12/31/2007	1.61	1.21	0.7515528
12/31/2015	1.07	0	
12/30/2016	2.04	1.728	0.84705882
12/31/2017	1.23	1.728	1.40487805

	Median	0.67147436

AVA US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	1.73	1.24	0.71676301
12/31/1991	1.34	1.24	0.92537313
12/31/1992	1.37	1.24	0.90510949
12/31/1993	1.44	1.24	0.86111111
12/30/1994	1.28	1.24	0.96875
12/29/1995	1.41	1.24	0.87943262
12/31/1996	1.35	1.24	0.91851852
12/31/1997	1.96	1.24	0.63265306
12/31/1998	1.28	1.05	0.8203125
12/31/1999	0.12	0.48	4
12/29/2000	1.47	0.48	0.32653061
12/31/2001	0.2	0.48	2.4
12/31/2002	0.6	0.48	0.8
12/31/2003	0.89	0.49	0.5505618
12/31/2004	0.72	0.515	0.71527778
12/30/2005	0.92	0.545	0.5923913
12/29/2006	1.46	0.57	0.39041096
12/31/2007	0.72	0.595	0.82638889
12/31/2008	1.36	0.69	0.50735294
12/31/2009	1.58	0.81	0.51265823
12/31/2010	1.65	1	0.60606061
12/30/2011	1.72	1.1	0.63953488
12/31/2012	1.32	1.16	0.87878788
12/31/2013	1.85	1.22	0.65945946
12/31/2014	3.1	1.27	0.40967742
12/31/2015	1.97	1.32	0.67005076
12/30/2016	2.15	1.37	0.6372093
12/31/2017	1.79	1.43	0.79888268
		Median	0.71602039

BKH US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	1.1156	0.7289	0.65337038
12/31/1991	1.1067	0.7822	0.70678594
12/31/1992	1.1533	0.8267	0.71681262
12/31/1993	1.1067	0.8533	0.77103099
12/30/1994	1.1067	0.88	0.79515677
12/29/1995	1.1867	0.8933	0.75275975
12/31/1996	1.4	0.92	0.65714286
12/31/1997	1.49	0.9467	0.63536913
12/31/1998	1.19	1	0.84033613
12/31/1999	1.73	1.04	0.60115607
12/29/2000	2.37	1.08	0.4556962
12/31/2001	3.42	1.12	0.32748538
12/31/2002	2.26	1.16	0.51327434
12/31/2003	1.97	1.2	0.60913706
12/31/2004	1.76	1.24	0.70454545
12/30/2005	1	1.28	1.28
12/29/2006	2.42	1.32	0.54545455
12/31/2007	2.64	1.37	0.51893939
12/31/2008	2.75	1.4	0.50909091
12/31/2009	2.11	1.42	0.67298578
12/31/2010	1.76	1.44	0.81818182
12/30/2011	1.24	1.46	1.17741935
12/31/2012	1.85	1.48	0.8
12/31/2013	2.64	1.52	0.57575758
12/31/2014	2.93	1.56	0.53242321
12/31/2015	-0.71	1.62	-2.2816901
12/30/2016	1.37	1.68	1.22627737
12/31/2017	3.21	1.81	0.56386293
		Median	0.65525662

CNP US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	1.335	1.48	1.10861423
12/31/1991	1.62	1.48	0.91358025
12/31/1992	1.68	1.49	0.88690476
12/31/1993	1.6	1.5	0.9375
12/30/1994	1.625	1.5	0.92307692
12/29/1995	4.46	1.5	0.33632287
12/31/1996	1.66	1.5	0.90361446
12/31/1997	1.66	1.5	0.90361446
12/31/1998	-0.5	1.5	-3
12/31/1999	5.18	1.5	0.28957529
12/29/2000	1.56	1.5	0.96153846
12/31/2001	3.35	1.5	0.44776119
12/31/2002	-13.16	1.07	-0.08130699
12/31/2003	1.46	0.4	0.2739726
12/31/2004	-2.48	0.4	-0.16129032
12/30/2005	0.75	0.4	0.53333333
12/29/2006	1.33	0.6	0.45112782
12/31/2007	1.17	0.68	0.58119658
12/31/2008	1.3	0.73	0.56153846
12/31/2009	1.01	0.76	0.75247525
12/31/2010	1.07	0.78	0.72897196
12/30/2011	3.17	0.79	0.24921136
12/31/2012	0.97	0.81	0.83505155
12/31/2013	0.72	0.83	1.15277778
12/31/2014	1.42	0.95	0.66901408
12/31/2015	-1.61	0.99	-0.61490683
12/30/2016	1	1.03	1.03
12/31/2017	4.13	1.3475	0.32627119
		Median	0.62510533

CMS US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	-6.07	0.42	-0.0691928
12/31/1991	-3.44	0.48	-0.1395349
12/31/1992	-3.72	0.48	-0.1290323
12/31/1993	1.9	0.6	0.31578947
12/30/1994	2.09	0.78	0.37320574
12/29/1995	2.26	0.9	0.39823009
12/31/1996	2.44	1.02	0.41803279
12/31/1997	2.37	1.14	0.48101266
12/31/1998	2.62	1.26	0.48091603
12/31/1999	2.17	1.39	0.640553
12/29/2000	0.38	1.46	3.84210526
12/31/2001	-3.51	1.46	-0.4159544
12/31/2002	-4.68	1.09	-0.232906
12/31/2003	-0.3	#N/A N/A	
12/31/2004	0.64	#N/A N/A	
12/30/2005	-0.44	0	
12/29/2006	-0.41	0	
12/31/2007	-1.02	0.2	-0.1960784
12/31/2008	1.2	0.36	0.3
12/31/2009	0.91	1	1.0989011
12/31/2010	1.28	0.66	0.515625
12/30/2011	1.58	0.84	0.53164557
12/31/2012	1.42	0.96	0.67605634
12/31/2013	1.66	1.02	0.61445783
12/31/2014	1.74	1.08	0.62068966
12/31/2015	1.89	1.16	0.61375661
12/30/2016	1.98	1.24	0.62626263
12/31/2017	1.64	1.33	0.81097561
		Median	0.48096434

ED US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	2.32	1.82	0.78448276
12/31/1991	2.32	1.86	0.80172414
12/31/1992	2.46	1.9	0.77235772
12/31/1993	2.66	1.94	0.72932331
12/30/1994	2.98	2	0.67114094
12/29/1995	2.93	2.04	0.69624573
12/31/1996	2.93	2.08	0.70989761
12/31/1997	2.954	2.1	0.71090047
12/31/1998	3.042	2.12	0.69690993
12/31/1999	3.13	2.14	0.68370607
12/29/2000	2.74	2.18	0.79562044
12/31/2001	3.21	2.2	0.68535826
12/31/2002	3.02	2.22	0.73509934
12/31/2003	2.38	2.24	0.94117647
12/31/2004	2.27	2.26	0.99559471
12/30/2005	2.94	2.28	0.7755102
12/29/2006	2.95	2.3	0.77966102
12/31/2007	3.47	2.32	0.6685879
12/31/2008	4.37	2.34	0.53546911
12/31/2009	3.14	2.36	0.75159236
12/31/2010	3.47	2.38	0.68587896
12/30/2011	3.57	2.4	0.67226891
12/31/2012	3.86	2.42	0.62694301
12/31/2013	3.61	2.46	0.68144044
12/31/2014	3.71	2.52	0.67924528
12/31/2015	4.05	2.6	0.64197531
12/30/2016	4.12	2.68	0.65048544
12/31/2017	4.94	2.76	0.55870445
		Median	0.69657783

D US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	1.46	1.1167	0.76486301
12/31/1991	1.47	1.1567	0.78687075
12/31/1992	1.38	1.2	0.86956522
12/31/1993	1.56	1.24	0.79487179
12/30/1994	1.405	1.275	0.90747331
12/29/1995	1.225	1.29	1.05306122
12/31/1996	1.325	1.29	0.97358491
12/31/1997	1.075	1.29	1.2
12/31/1998	1.375	1.29	0.93818182
12/31/1999	0.74	1.29	1.74324324
12/29/2000	0.925	1.29	1.39459459
12/31/2001	1.075	1.29	1.2
12/31/2002	2.41	1.29	0.53526971
12/31/2003	0.5	1.29	2.58
12/31/2004	1.89	1.3	0.68783069
12/30/2005	1.5	1.34	0.89333333
12/29/2006	1.96	1.38	0.70408163
12/31/2007	3.88	1.46	0.37628866
12/31/2008	3.16	1.58	0.5
12/31/2009	2.17	1.75	0.80645161
12/31/2010	4.76	1.83	0.38445378
12/30/2011	2.45	1.97	0.80408163
12/31/2012	0.53	2.11	3.98113208
12/31/2013	2.93	2.25	0.76791809
12/31/2014	2.24	2.4	1.07142857
12/31/2015	3.2	2.59	0.809375
12/30/2016	3.44	2.8	0.81395349
12/31/2017	4.72	3.035	0.64300847
		Median	0.81166424

DTE US Equity

Date	TRAIL_12M_DILUTED_EF	EQY_DPS	Payout %
12/31/1990	3.26	1.78	0.54601227
12/31/1991	3.64	1.88	0.51648352
12/31/1992	3.79	1.98	0.52242744
12/31/1993	3.34	2.06	0.61676647
12/30/1994	2.67	2.06	0.77153558
12/29/1995	2.8	2.06	0.73571429
12/31/1996	2.13	2.06	0.96713615
12/31/1997	2.88	2.06	0.71527778
12/31/1998	3.05	2.06	0.67540984
12/31/1999	3.33	2.06	0.61861862
12/29/2000	3.27	2.06	0.62996942
12/31/2001	2.16	2.06	0.9537037
12/31/2002	3.83	2.06	0.53785901
12/31/2003	3.09	2.06	0.66666667
12/31/2004	2.49	2.06	0.82730924
12/30/2005	3.05	2.06	0.67540984
12/29/2006	2.43	2.075	0.85390947
12/31/2007	5.7	2.12	0.37192982
12/31/2008	3.36	2.12	0.63095238
12/31/2009	3.24	2.12	0.65432099
12/31/2010	3.74	2.18	0.5828877
12/30/2011	4.18	2.32	0.55502392
12/31/2012	3.55	2.42	0.68169014
12/31/2013	3.76	2.59	0.68882979
12/31/2014	5.1	2.69	0.52745098
12/31/2015	4.05	2.84	0.70123457
12/30/2016	4.83	3.06	0.63354037
12/31/2017	6.32	3.36	0.53164557
		Median	0.64393068

DUK US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	3.6	2.4	0.66666667
12/31/1991	3.9	2.52	0.64615385
12/31/1992	3.315	2.64	0.79638009
12/31/1993	4.2	2.76	0.65714286
12/30/1994	4.32	2.88	0.66666667
12/29/1995	4.875	3	0.61538462
12/31/1996	4.245	3.12	0.73498233
12/31/1997	3.75	3.24	0.864
12/31/1998	5.1	3.3	0.64705882
12/31/1999	6.09	3.3	0.54187192
12/29/2000	7.14	3.3	0.46218487
12/31/2001	7.32	3.3	0.45081967
12/31/2002	3.66	3.3	0.90163934
12/31/2003	-4.44	3.3	-0.74324324
12/31/2004	4.62	3.3	0.71428571
12/30/2005	5.64	3.51	0.62234043
12/29/2006	4.71	3.78	0.80254777
12/31/2007	3.54	2.58	0.72881356
12/31/2008	3.21	2.7	0.8411215
12/31/2009	2.49	2.82	1.13253012
12/31/2010	3	2.91	0.97
12/30/2011	3.84	2.97	0.7734375
12/31/2012	3.07	3.03	0.98697068
12/31/2013	3.76	3.09	0.82180851
12/31/2014	2.66	3.15	1.18421053
12/31/2015	4.05	3.24	0.8
12/30/2016	3.11	3.36	1.08038585
12/31/2017	4.36	3.49	0.80045872
		Median	0.75420992

EIX US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	1.8	1.31	0.72777778
12/31/1991	1.605	1.35	0.8411215
12/31/1992	1.66	1.39	0.8373494
12/31/1993	1.43	1.415	0.98951049
12/30/1994	1.52	1.105	0.72697368
12/29/1995	1.66	0.75	0.45180723
12/31/1996	1.63	1.25	0.76687117
12/31/1997	1.73	1	0.57803468
12/31/1998	1.84	1.04	0.56521739
12/31/1999	1.79	1.08	0.60335196
12/29/2000	-5.84	0.84	-0.1438356
12/31/2001	3.17	#N/A N/A	
12/31/2002	3.28	0	
12/31/2003	2.5	0.2	0.08
12/31/2004	2.77	0.85	0.30685921
12/30/2005	3.43	1.02	0.29737609
12/29/2006	3.61	1.1	0.30470914
12/31/2007	3.31	1.175	0.35498489
12/31/2008	3.73	1.225	0.32841823
12/31/2009	2.58	1.245	0.48255814
12/31/2010	3.8176	1.265	0.33136002
12/30/2011	-0.11	1.285	-11.681818
12/31/2012	-0.56	1.3125	-2.34375
12/31/2013	2.78	1.3675	0.49190647
12/31/2014	4.89	1.4825	0.30316973
12/31/2015	3.1	1.7325	0.55887097
12/30/2016	3.97	1.9825	0.49937028
12/31/2017	1.72	2.2325	1.29796512
		Median	0.48723231

EE US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1996	0.523	0	
12/31/1997	0.639	0	
12/31/1998	0.754	0	
12/31/1999	0.473	0	
12/29/2000	1.06	0	
12/31/2001	1.23	0	
12/31/2002	0.57	0	
12/31/2003	1.23	0	
12/31/2004	0.73	0	
12/30/2005	0.74	0	
12/29/2006	1.4	0	
12/31/2007	1.63	0	
12/31/2008	1.73	0	
12/31/2009	1.5	0	
12/31/2010	2.31	0	
12/30/2011	2.48	0.66	0.26612903
12/31/2012	2.26	0.97	0.42920354
12/31/2013	2.2	1.045	0.475
12/31/2014	2.27	1.105	0.48678414
12/31/2015	2.03	1.165	0.57389163
12/30/2016	2.39	1.225	0.5125523
12/31/2017	2.42	1.315	0.54338843

	Median	0.48678414

ETR US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	2.44	1.05	0.43032787
12/31/1991	2.64	1.25	0.47348485
12/31/1992	2.48	1.45	0.58467742
12/31/1993	3.16	1.65	0.5221519
12/30/1994	1.49	1.8	1.20805369
12/29/1995	2.28	1.8	0.78947368
12/31/1996	1.83	1.8	0.98360656
12/31/1997	1.03	1.8	1.74757282
12/31/1998	2.997	1.5	0.5005005
12/31/1999	2.25	1.2	0.53333333
12/29/2000	2.97	1.215	0.40909091
12/31/2001	3.23	1.275	0.39473684
12/31/2002	2.64	1.34	0.50757576
12/31/2003	4.01	1.6	0.39900249
12/31/2004	3.93	1.89	0.48091603
12/30/2005	4.19	2.16	0.51551313
12/29/2006	5.36	2.16	0.40298507
12/31/2007	5.6	2.58	0.46071429
12/31/2008	6.0721	3	0.49406301
12/31/2009	6.3	3	0.47619048
12/31/2010	6.66	3.24	0.48648649
12/30/2011	7.55	3.32	0.4397351
12/31/2012	4.76	3.32	0.69747899
12/31/2013	3.99	3.32	0.8320802
12/31/2014	5.22	3.32	0.63601533
12/31/2015	-0.99	3.34	-3.3737374
12/30/2016	-3.26	3.42	-1.0490798
12/31/2017	2.28	3.5	1.53508772
		Median	0.49728176

EXC US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1997	-3.4	0.9	-0.26470588
12/29/2000	1.435	0.455	0.31707317
12/31/2001	2.215	0.634	0.28623025
12/31/2002	2.22	0.88	0.3963964
12/31/2003	1.375	0.96	0.69818182
12/31/2004	2.78	1.26	0.45323741
12/30/2005	1.36	1.6	1.17647059
12/29/2006	2.35	1.6	0.68085106
12/31/2007	4.05	1.76	0.4345679
12/31/2008	4.13	2.03	0.49152542
12/31/2009	4.09	2.1	0.51344743
12/31/2010	3.87	2.1	0.54263566
12/30/2011	3.75	2.1	0.56
12/31/2012	1.42	2.1	1.47887324
12/31/2013	2	1.46	0.73
12/31/2014	1.88	1.24	0.65957447
12/31/2015	2.54	1.24	0.48818898
12/30/2016	1.22	1.264	1.03606557
12/31/2017	3.97	1.31	0.32997481

	Median	0.51344743

FE US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/29/1995	2.05	#N/A N/A	
12/31/1996	2.1	#N/A N/A	
12/31/1997	1.94	1.5	0.77319588
12/31/1998	1.82	1.5	0.82417582
12/31/1999	2.5	1.5	0.6
12/29/2000	2.69	1.5	0.55762082
12/31/2001	2.81	1.5	0.53380783
12/31/2002	2.14	1.5	0.70093458
12/31/2003	1.39	1.5	1.07913669
12/31/2004	2.67	1.9125	0.71629213
12/30/2005	2.61	1.705	0.6532567
12/29/2006	3.81	1.85	0.4855643
12/31/2007	4.22	2.05	0.48578199
12/31/2008	4.38	2.2	0.50228311
12/31/2009	3.29	2.2	0.66869301
12/31/2010	2.42	2.2	0.90909091
12/30/2011	2.21	2.2	0.99547511
12/31/2012	1.84	2.2	1.19565217
12/31/2013	0.94	1.65	1.75531915
12/31/2014	0.71	1.44	2.02816901
12/31/2015	1.37	1.44	1.05109489
12/30/2016	-14.49	1.44	-0.0993789
12/31/2017	-3.88	1.44	-0.371134

	Median	0.70093458

GXP US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	1.555	1.31	0.842444
12/31/1991	1.58	1.37	0.867089
12/31/1992	1.35	1.43	1.059259
12/31/1993	1.66	1.46	0.879518
12/30/1994	1.64	1.5	0.914634
12/29/1995	1.92	1.54	0.802083
12/31/1996	1.69	1.59	0.940828
12/31/1997	1.18	1.62	1.372881
12/31/1998	1.89	1.64	0.867725
12/31/1999	1.26	1.66	1.31746
12/29/2000	2.54	1.66	0.653543
12/31/2001	-0.42	1.66	-3.95238
12/31/2002	1.99	1.66	0.834171
12/31/2003	2.07	1.66	0.801932
12/31/2004	2.49	1.66	0.666667
12/30/2005	2.15	1.66	0.772093
12/29/2006	1.61	1.66	1.031056
12/31/2007	1.85	1.66	0.897297
12/31/2008	1.51	1.66	1.099338
12/31/2009	1.14	0.83	0.72807
12/31/2010	1.53	0.83	0.542484
12/30/2011	1.25	0.835	0.668
12/31/2012	1.35	0.855	0.633333
12/31/2013	1.62	0.8825	0.544753
12/31/2014	1.57	0.935	0.595541
12/31/2015	1.37	0.9975	0.728102
12/30/2016	1.61	1.0625	0.659938
12/31/2017	-0.67	1.1	-1.64179
		Median	0.802008

HE US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	1.085	1.085	1
12/31/1991	1.2	1.105	0.92083333
12/31/1992	-0.24	1.125	-4.6875
12/31/1993	0.94	1.145	1.21808511
12/30/1994	1.3	1.165	0.89615385
12/29/1995	1.33	1.185	0.89097744
12/31/1996	1.295	1.205	0.93050193
12/31/1997	1.3734	1.22	0.88830639
12/31/1998	1.32	1.24	0.93939394
12/31/1999	1.5	1.24	0.82666667
12/29/2000	0.7	1.24	1.77142857
12/31/2001	1.235	1.24	1.00404858
12/31/2002	1.62	1.24	0.7654321
12/31/2003	1.525	1.24	0.81311475
12/31/2004	1.38	1.24	0.89855072
12/30/2005	1.56	1.24	0.79487179
12/29/2006	1.33	1.24	0.93233083
12/31/2007	1.03	1.24	1.2038835
12/31/2008	1.07	1.24	1.1588785
12/31/2009	0.91	1.24	1.36263736
12/31/2010	1.21	1.24	1.02479339
12/30/2011	1.44	1.24	0.86111111
12/31/2012	1.42	1.24	0.87323944
12/31/2013	1.62	1.24	0.7654321
12/31/2014	1.63	1.24	0.7607362
12/31/2015	1.5	1.24	0.82666667
12/30/2016	2.29	1.24	0.54148472
12/31/2017	1.52	1.24	0.81578947
		Median	0.89356564

IDA US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	1.91	1.86	0.97382199
12/31/1991	1.56	1.86	1.19230769
12/31/1992	1.55	1.86	1.2
12/31/1993	2.14	1.86	0.86915888
12/30/1994	1.8	1.86	1.03333333
12/29/1995	2.1	1.86	0.88571429
12/31/1996	2.21	1.86	0.84162896
12/31/1997	2.32	1.86	0.80172414
12/31/1998	2.37	1.86	0.78481013
12/31/1999	2.43	1.86	0.7654321
12/29/2000	3.72	1.86	0.5
12/31/2001	3.35	1.86	0.55522388
12/31/2002	1.63	1.86	1.14110429
12/31/2003	1.22	1.695	1.38934426
12/31/2004	1.9	1.2	0.63157895
12/30/2005	1.5	1.2	0.8
12/29/2006	2.51	1.2	0.47808765
12/31/2007	1.86	1.2	0.64516129
12/31/2008	2.17	1.2	0.55299539
12/31/2009	2.64	1.2	0.45454545
12/31/2010	2.95	1.2	0.40677966
12/30/2011	3.36	1.2	0.35714286
12/31/2012	3.46	1.37	0.39595376
12/31/2013	3.64	1.57	0.43131868
12/31/2014	3.85	1.76	0.45714286
12/31/2015	3.87	1.92	0.49612403
12/30/2016	3.94	2.08	0.52791878
12/31/2017	4.21	2.24	0.53206651
		Median	0.63837012

MGEE US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	0.9067	0.7644	0.84305724
12/31/1991	1.0133	0.7763	0.76611073
12/31/1992	0.9689	0.7956	0.82113737
12/31/1993	1.0044	0.8178	0.81421744
12/30/1994	1.0178	0.8311	0.81656514
12/29/1995	0.9911	0.84	0.84754313
12/31/1996	0.2667	0.8488	3.18260217
12/31/1997	0.9333	0.858	0.91931855
12/31/1998	0.92	0.8667	0.94206522
12/31/1999	0.9867	0.872	0.88375393
12/29/2000	1.1133	0.8787	0.78927513
12/31/2001	1.08	0.8853	0.81972222
12/31/2002	1.1267	0.8933	0.79284637
12/31/2003	1.14	0.9	0.78947368
12/31/2004	1.18	0.9067	0.76838983
12/30/2005	1.0467	0.9133	0.87255183
12/29/2006	1.3733	0.9267	0.67479793
12/31/2007	1.5133	0.94	0.62115906
12/31/2008	1.5867	0.9533	0.60080671
12/31/2009	1.4733	0.9733	0.66062581
12/31/2010	1.6667	0.9933	0.59596808
12/30/2011	1.76	1.0133	0.57573864
12/31/2012	1.86	1.04	0.55913978
12/31/2013	2.16	1.07	0.49537037
12/31/2014	2.32	1.11	0.47844828
12/31/2015	2.06	1.16	0.5631068
12/30/2016	2.18	1.21	0.55504587
12/31/2017	2.82	1.26	0.44680851
		Median	0.77883248

NEE US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	-1.43	1.17	-0.81818182
12/31/1991	0.74	1.195	1.61486486
12/31/1992	1.325	1.215	0.91698113
12/31/1993	1.15	1.235	1.07391304
12/30/1994	1.455	0.94	0.64604811
12/29/1995	1.58	0.88	0.55696203
12/31/1996	1.665	0.92	0.55255255
12/31/1997	1.785	0.96	0.53781513
12/31/1998	1.925	1	0.51948052
12/31/1999	2.035	1.04	0.51105651
12/29/2000	2.07	1.08	0.52173913
12/31/2001	2.31	1.12	0.48484848
12/31/2002	1.365	1.16	0.84981685
12/31/2003	2.5	1.2	0.48
12/31/2004	2.455	1.3	0.52953157
12/30/2005	2.34	1.42	0.60683761
12/29/2006	3.23	1.5	0.46439628
12/31/2007	3.27	1.64	0.50152905
12/31/2008	4.07	1.78	0.43734644
12/31/2009	3.97	1.89	0.47607053
12/31/2010	4.74	2	0.42194093
12/30/2011	4.59	2.2	0.47930283
12/31/2012	4.56	2.4	0.52631579
12/31/2013	4.47	2.64	0.59060403
12/31/2014	5.6	2.9	0.51785714
12/31/2015	6.06	3.08	0.50825083
12/30/2016	6.25	3.48	0.5568
12/31/2017	11.38	3.93	0.34534271
		Median	0.52060982

ES US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	1.94	1.76	0.90721649
12/31/1991	2.12	1.76	0.83018868
12/31/1992	2.02	1.76	0.87128713
12/31/1993	2.02	1.76	0.87128713
12/30/1994	2.3	1.76	0.76521739
12/29/1995	2.24	1.76	0.78571429
12/31/1996	0.01	1.38	138
12/31/1997	-1.01	0.25	-0.2475248
12/31/1998	-1.124	0	
12/31/1999	0.26	0.1	0.38461538
12/29/2000	-0.2	#N/A N/A	
12/31/2001	1.79	0.45	0.25139665
12/31/2002	1.18	0.525	0.44491525
12/31/2003	0.91	0.575	0.63186813
12/31/2004	0.91	0.625	0.68681319
12/30/2005	-1.93	0.675	-0.3497409
12/29/2006	3.05	0.725	0.23770492
12/31/2007	1.59	0.775	0.48742138
12/31/2008	1.67	0.825	0.49401198
12/31/2009	1.91	0.95	0.4973822
12/31/2010	2.19	1.025	0.46803653
12/30/2011	2.22	1.1	0.4954955
12/31/2012	1.89	1.32	0.6984127
12/31/2013	2.49	1.47	0.59036145
12/31/2014	2.58	1.57	0.60852713
12/31/2015	2.76	1.67	0.60507246
12/30/2016	2.96	1.78	0.60135135
12/31/2017	3.11	1.9	0.61093248
		Median	0.60321191

NWE US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/2002	-30.04	1.27	-0.04227696
12/31/2003	-3.44	0	
12/31/2004	15.29	0	
12/30/2005	1.65	1	0.60606061
12/29/2006	1.01	1.24	1.22772277
12/31/2007	1.44	1.28	0.88888889
12/31/2008	1.77	1.32	0.74576271
12/31/2009	2.02	1.34	0.66336634
12/31/2010	2.14	1.36	0.63551402
12/30/2011	2.53	1.44	0.56916996
12/31/2012	2.66	1.48	0.55639098
12/31/2013	2.46	1.52	0.61788618
12/31/2014	2.99	1.6	0.53511706
12/31/2015	3.17	1.92	0.60567823
12/30/2016	3.39	2	0.5899705
12/31/2017	3.34	2.1	0.62874251

	Median	0.61197339

OGE US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	0.845	0.62	0.73372781
12/31/1991	0.8175	0.645	0.78899083
12/31/1992	0.605	0.665	1.09917355
12/31/1993	0.695	0.665	0.95683453
12/30/1994	0.7525	0.665	0.88372093
12/29/1995	0.7625	0.665	0.87213115
12/31/1996	0.8125	0.665	0.81846154
12/31/1997	0.8067	0.665	0.8243461
12/31/1998	1.022	0.665	0.65068493
12/31/1999	0.97	0.665	0.68556701
12/29/2000	0.945	0.665	0.7037037
12/31/2001	0.645	0.665	1.03100775
12/31/2002	0.58	0.665	1.14655172
12/31/2003	0.79	0.665	0.84177215
12/31/2004	0.865	0.665	0.76878613
12/30/2005	1.16	0.665	0.57327586
12/29/2006	1.42	0.6687	0.47091549
12/31/2007	1.32	0.6837	0.51795455
12/31/2008	1.245	0.6988	0.56128514
12/31/2009	1.33	0.7138	0.53669173
12/31/2010	1.495	0.7312	0.48909699
12/30/2011	1.725	0.7588	0.43988406
12/31/2012	1.79	0.7975	0.44553073
12/31/2013	1.94	0.85125	0.43878866
12/31/2014	1.98	0.95	0.47979798
12/31/2015	1.36	1.05	0.77205882
12/30/2016	1.69	1.155	0.68343195
12/31/2017	3.1	1.27	0.40967742
		Median	0.69463536

OTTR US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	0.995	0.78	0.7839196
12/31/1991	1.075	0.8	0.74418605
12/31/1992	1.085	0.82	0.75576037
12/31/1993	1.115	0.84	0.75336323
12/30/1994	1.17	0.86	0.73504274
12/29/1995	1.19	0.88	0.7394958
12/31/1996	1.23	0.9	0.73170732
12/31/1997	1.29	0.93	0.72093023
12/31/1998	1.36	0.96	0.70588235
12/31/1999	1.79	0.99	0.55307263
12/29/2000	1.59	1.02	0.64150943
12/31/2001	1.68	1.04	0.61904762
12/31/2002	1.79	1.06	0.59217877
12/31/2003	1.51	1.08	0.71523179
12/31/2004	1.58	1.1	0.69620253
12/30/2005	2.11	1.12	0.53080569
12/29/2006	1.7	1.15	0.67647059
12/31/2007	1.78	1.17	0.65730337
12/31/2008	1.09	1.19	1.09174312
12/31/2009	0.71	1.19	1.67605634
12/31/2010	-0.06	1.19	-19.833333
12/30/2011	-0.4	1.19	-2.975
12/31/2012	-0.17	1.19	-7
12/31/2013	1.39	1.19	0.85611511
12/31/2014	1.57	1.21	0.77070064
12/31/2015	1.58	1.23	0.77848101
12/30/2016	1.61	1.25	0.77639752
12/31/2017	1.82	1.28	0.7032967
		Median	0.71808101

PCG US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	2.1	1.52	0.72380952
12/31/1991	2.24	1.64	0.73214286
12/31/1992	2.58	1.76	0.68217054
12/31/1993	2.33	1.88	0.80686695
12/30/1994	2.21	1.96	0.88687783
12/29/1995	2.99	1.96	0.65551839
12/31/1996	1.75	1.77	1.01142857
12/31/1997	1.75	#N/A N/A	
12/31/1998	1.88	1.2	0.63829787
12/31/1999	-0.2	1.2	-6
12/29/2000	-9.29	1.2	-0.12917115
12/31/2001	3.02	0	
12/31/2002	-2.36	0	
12/31/2003	1.06	0	
12/31/2004	10.57	0.33	0.03122044
12/30/2005	2.37	1.23	0.51898734
12/29/2006	2.76	1.32	0.47826087
12/31/2007	2.78	1.44	0.51798561
12/31/2008	3.75	1.56	0.416
12/31/2009	3.2	1.68	0.525
12/31/2010	2.82	1.82	0.64539007
12/30/2011	2.1	1.82	0.86666667
12/31/2012	1.92	1.82	0.94791667
12/31/2013	1.83	1.82	0.99453552
12/31/2014	3.06	1.82	0.59477124
12/31/2015	1.79	1.82	1.01675978
12/30/2016	2.78	1.93	0.6942446
12/31/2017	3.21	1.55	0.48286604
		Median	0.65045423

PNW US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	1.12	#N/A N/A	
12/31/1991	-2.15	#N/A N/A	
12/31/1992	1.8	#N/A N/A	
12/31/1993	2.17	0.2	0.0921659
12/30/1994	2.3	0.825	0.35869565
12/29/1995	2.15	0.925	0.43023256
12/31/1996	2.06	1.025	0.49757282
12/31/1997	2.74	1.125	0.41058394
12/31/1998	2.85	1.225	0.42982456
12/31/1999	1.97	1.325	0.67258883
12/29/2000	3.56	1.425	0.4002809
12/31/2001	3.68	1.525	0.41440217
12/31/2002	1.76	1.625	0.92329545
12/31/2003	2.63	1.725	0.65589354
12/31/2004	2.66	1.825	0.68609023
12/30/2005	1.82	1.925	1.05769231
12/29/2006	3.27	2.025	0.61926606
12/31/2007	3.05	2.1	0.68852459
12/31/2008	2.4	2.1	0.875
12/31/2009	0.67	2.1	3.13432836
12/31/2010	3.27	2.1	0.64220183
12/30/2011	3.09	2.1	0.67961165
12/31/2012	3.45	2.67	0.77391304
12/31/2013	3.66	2.23	0.60928962
12/31/2014	3.58	2.33	0.65083799
12/31/2015	3.92	2.41	0.61479592
12/30/2016	3.95	2.53	0.64050633
12/31/2017	4.35	2.66	0.61149425
		Median	0.64050633

PNM US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	-0.1533	#N/A N/A	
12/31/1991	0.2133	#N/A N/A	
12/31/1992	-1.78	#N/A N/A	
12/31/1993	-1.0933	#N/A N/A	
12/30/1994	1.18	#N/A N/A	
12/29/1995	1.1467	#N/A N/A	
12/31/1996	1.14	0.24	0.21052632
12/31/1997	1.2733	0.42	0.32985157
12/31/1998	1.3	0.5133	0.39484615
12/31/1999	1.34	0.5333	0.39798507
12/29/2000	1.6867	0.5333	0.31617952
12/31/2001	2.5133	0.5333	0.21219114
12/31/2002	1.0733	0.5733	0.53414702
12/31/2003	1.58	0.6067	0.38398734
12/31/2004	1.43	0.63	0.44055944
12/30/2005	1	0.785	0.785
12/29/2006	1.71	0.88	0.51461988
12/31/2007	0.96	0.92	0.95833333
12/31/2008	-3.24	0.605	-0.1867284
12/31/2009	1.36	0.5	0.36764706
12/31/2010	-0.49	0.5	-1.02040816
12/30/2011	1.96	0.5	0.25510204
12/31/2012	1.31	0.58	0.44274809
12/31/2013	1.25	0.68	0.544
12/31/2014	1.45	0.755	0.52068966
12/31/2015	0.2	0.82	4.1
12/30/2016	1.46	0.9025	0.61815068
12/31/2017	1	0.9925	0.9925
		Median	0.41927226

POR US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1992	2.3	0	
12/31/1993	2.17	0	
12/30/1994	2.29	0	
12/29/1995	1.94	0	
12/31/1996	3.58	0	
12/31/1997	2.899	1.47	0.5070714
12/31/1998	3.16	1.15	0.36392405
12/31/1999	2.95	1.89	0.64067797
12/29/2000	3.25	1.89	0.58153846
12/31/2001	0.748	0.935	1.25
12/31/2002	1.5	0.63	0.42
12/31/2003	1.33	0	
12/31/2004	2.15	0	
12/30/2005	1.5	3.51	2.34
12/29/2006	1.14	0.675	0.59210526
12/31/2007	2.33	0.93	0.39914163
12/31/2008	1.39	0.97	0.69784173
12/31/2009	1.31	1.01	0.77099237
12/31/2010	1.66	1.035	0.62349398
12/30/2011	1.95	1.055	0.54102564
12/31/2012	1.87	1.075	0.57486631
12/31/2013	1.35	1.095	0.81111111
12/31/2014	2.18	1.115	0.51146789
12/31/2015	2.04	1.18	0.57843137
12/30/2016	2.16	1.26	0.58333333
12/31/2017	2.1	1.34	0.63809524
		Median	0.58333333

PPL US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	0.9875	0.745	0.75443038
12/31/1991	1.0025	0.775	0.77306733
12/31/1992	1.01	0.8	0.79207921
12/31/1993	1.035	0.825	0.79710145
12/30/1994	0.705	0.835	1.18439716
12/29/1995	1.025	0.835	0.81463415
12/31/1996	1.025	0.835	0.81463415
12/31/1997	0.9	0.835	0.92777778
12/31/1998	-1.73	0.6675	-0.38583815
12/31/1999	1.42	0.5	0.35211268
12/29/2000	1.72	0.53	0.30813953
12/31/2001	0.61	0.53	0.86885246
12/31/2002	0.68	0.72	1.05882353
12/31/2003	2.12	0.77	0.36320755
12/31/2004	1.89	0.82	0.43386243
12/30/2005	1.77	0.96	0.54237288
12/29/2006	2.24	1.1	0.49107143
12/31/2007	3.35	1.22	0.3641791
12/31/2008	2.47	1.34	0.54251012
12/31/2009	1.08	1.38	1.27777778
12/31/2010	2.17	1.4	0.64516129
12/30/2011	2.7	1.4	0.51851852
12/31/2012	2.6	1.44	0.55384615
12/31/2013	1.76	1.47	0.83522727
12/31/2014	2.61	1.49	0.57088123
12/31/2015	1.01	1.5	1.48514851
12/30/2016	2.79	1.52	0.54480287
12/31/2017	1.64	1.58	0.96341463
		Median	0.69979584

PEG US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	1.28	1.045	0.81640625
12/31/1991	1.215	1.065	0.87654321
12/31/1992	1.085	1.08	0.99539171
12/31/1993	1.3	1.08	0.83076923
12/30/1994	1.39	1.08	0.77697842
12/29/1995	1.355	1.08	0.79704797
12/31/1996	1.26	1.08	0.85714286
12/31/1997	1.205	1.08	0.89626556
12/31/1998	1.395	1.08	0.77419355
12/31/1999	-0.185	1.08	-5.8378378
12/29/2000	1.775	1.08	0.6084507
12/31/2001	1.85	1.08	0.58378378
12/31/2002	0.565	1.08	1.91150442
12/31/2003	2.535	1.08	0.4260355
12/31/2004	1.525	1.1	0.72131148
12/30/2005	1.355	1.12	0.82656827
12/29/2006	1.465	1.14	0.778157
12/31/2007	2.62	0.585	0.22328244
12/31/2008	2.34	1.29	0.55128205
12/31/2009	3.14	1.33	0.42356688
12/31/2010	3.08	1.37	0.44480519
12/30/2011	2.96	1.37	0.46283784
12/31/2012	2.51	1.42	0.56573705
12/31/2013	2.45	1.44	0.5877551
12/31/2014	2.99	1.48	0.49498328
12/31/2015	3.3	1.56	0.47272727
12/30/2016	1.75	1.64	0.93714286
12/31/2017	3.1	1.72	0.55483871
		Median	0.66488109

SCG US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	2.22	1.26	0.56756757
12/31/1991	1.685	1.31	0.77744807
12/31/1992	1.42	1.34	0.94366197
12/31/1993	1.86	1.37	0.73655914
12/30/1994	1.2185	1.41	1.15716044
12/29/1995	1.7	1.44	0.84705882
12/31/1996	2.05	1.47	0.71707317
12/31/1997	2.06	1.51	0.73300971
12/31/1998	2.12	1.54	0.72641509
12/31/1999	1.73	1.32	0.76300578
12/29/2000	2.4	1.15	0.47916667
12/31/2001	5.15	1.2	0.23300971
12/31/2002	-1.34	1.3	-0.9701493
12/31/2003	2.54	1.38	0.54330709
12/31/2004	2.3	1.46	0.63478261
12/30/2005	2.81	1.56	0.55516014
12/29/2006	2.68	1.68	0.62686567
12/31/2007	2.74	1.76	0.64233577
12/31/2008	2.95	1.84	0.62372881
12/31/2009	2.85	1.88	0.65964912
12/31/2010	2.98	1.9	0.63758389
12/30/2011	2.97	1.94	0.65319865
12/31/2012	3.15	1.98	0.62857143
12/31/2013	3.39	2.03	0.59882006
12/31/2014	3.79	2.1	0.55408971
12/31/2015	5.22	2.18	0.41762452
12/30/2016	4.16	2.3	0.55288462
12/31/2017	-0.83	2.45	-2.9518072
		Median	0.63167702

SRE US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1996	1.77	#N/A N/A	
12/31/1997	1.82	1.27	0.6978022
12/31/1998	1.24	1.56	1.25806452
12/31/1999	1.66	1.56	0.93975904
12/29/2000	2.06	1	0.48543689
12/31/2001	2.52	1	0.3968254
12/31/2002	2.87	1	0.34843206
12/31/2003	3.03	1	0.330033
12/31/2004	3.83	1	0.26109661
12/30/2005	3.65	1.16	0.31780822
12/29/2006	5.38	1.2	0.22304833
12/31/2007	4.16	1.24	0.29807692
12/31/2008	4.43	1.37	0.30925508
12/31/2009	4.52	1.56	0.34513274
12/31/2010	2.98	1.56	0.52348993
12/30/2011	5.51	1.92	0.34845735
12/31/2012	3.48	2.4	0.68965517
12/31/2013	4.01	2.52	0.62842893
12/31/2014	4.63	2.64	0.57019438
12/31/2015	5.37	2.8	0.52141527
12/30/2016	5.46	3.02	0.55311355
12/31/2017	1.01	3.29	3.25742574

Median	0.48543689

SO US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	0.955	1.07	1.12041885
12/31/1991	1.39	1.07	0.76978417
12/31/1992	1.51	1.1	0.72847682
12/31/1993	1.57	1.14	0.72611465
12/30/1994	1.52	1.18	0.77631579
12/29/1995	1.66	1.22	0.73493976
12/31/1996	1.68	1.26	0.75
12/31/1997	1.419	1.3	0.91613813
12/31/1998	1.402	1.34	0.95577746
12/31/1999	1.86	1.34	0.72043011
12/29/2000	2.01	1.34	0.66666667
12/31/2001	1.82	1.34	0.73626374
12/31/2002	1.85	1.355	0.73243243
12/31/2003	2.02	1.385	0.68564356
12/31/2004	2.06	1.415	0.6868932
12/30/2005	2.13	1.475	0.69248826
12/29/2006	2.1	1.535	0.73095238
12/31/2007	2.28	1.595	0.6995614
12/31/2008	2.25	1.6625	0.73888889
12/31/2009	2.06	1.7325	0.84101942
12/31/2010	2.36	1.8025	0.76377119
12/30/2011	2.55	1.8725	0.73431373
12/31/2012	2.67	1.9425	0.72752809
12/31/2013	1.87	2.0125	1.07620321
12/31/2014	2.18	2.0825	0.95527523
12/31/2015	2.6	2.1525	0.82788462
12/30/2016	2.57	2.2225	0.86478599
12/31/2017	0.84	2.3	2.73809524
		Median	0.73757631

VVC US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1999	1.48	0.94	0.63513514
12/29/2000	1.17	0.74	0.63247863
12/31/2001	0.79	1.03	1.30379747
12/31/2002	1.68	1.07	0.63690476
12/31/2003	1.57	1.11	0.70700637
12/31/2004	1.42	1.15	0.80985915
12/30/2005	1.8	1.19	0.66111111
12/29/2006	1.43	1.23	0.86013986
12/31/2007	1.87	1.27	0.67914439
12/31/2008	1.63	1.31	0.80368098
12/31/2009	1.64	1.345	0.82012195
12/31/2010	1.64	1.365	0.83231707
12/30/2011	1.73	1.385	0.80057803
12/31/2012	1.94	1.405	0.7242268
12/31/2013	1.66	1.425	0.85843373
12/31/2014	2.02	1.46	0.72277228
12/31/2015	2.39	1.54	0.64435146
12/30/2016	2.55	1.62	0.63529412
12/31/2017	2.6	1.71	0.65769231

Median	0.72277228

WR US Equity Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	2.25	1.8	0.8
12/31/1991	2.41	2.04	0.84647303
12/31/1992	2.2	1.9	0.86363636
12/31/1993	2.76	1.94	0.70289855
12/30/1994	2.82	1.98	0.70212766
12/29/1995	2.71	2.02	0.74538745
12/31/1996	2.41	2.06	0.85477178
12/31/1997	7.5943	2.1	0.27652318
12/31/1998	0.673	2.14	3.17979198
12/31/1999	0.2	2.14	10.7
12/29/2000	1.96	1.435	0.73214286
12/31/2001	-0.31	1.2	-3.8709677
12/31/2002	-10.98	1.2	-0.1092896
12/31/2003	1.15	0.76	0.66086957
12/31/2004	2.13	0.8	0.37558685
12/30/2005	1.54	0.92	0.5974026
12/29/2006	1.87	1	0.53475936
12/31/2007	1.83	1.08	0.59016393
12/31/2008	1.7	1.16	0.68235294
12/31/2009	1.58	1.2	0.75949367
12/31/2010	1.8	1.24	0.68888889
12/30/2011	1.93	1.28	0.66321244
12/31/2012	2.15	1.32	0.61395349
12/31/2013	2.27	1.36	0.59911894
12/31/2014	2.35	1.4	0.59574468
12/31/2015	2.09	1.44	0.68899522
12/30/2016	2.43	1.52	0.6255144
12/31/2017	2.27	1.6	0.70484581
		Median	0.68562092

WEC US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	0.9233	0.5783	0.6263403
12/31/1991	0.9367	0.6117	0.65303726
12/31/1992	0.835	0.6425	0.76946108
12/31/1993	0.9	0.6706	0.74511111
12/30/1994	0.835	0.6981	0.8360479
12/29/1995	1.065	0.7275	0.68309859
12/31/1996	0.985	0.7538	0.76527919
12/31/1997	0.27	0.3837	1.42111111
12/31/1998	0.825	0.7775	0.94242424
12/31/1999	0.895	0.78	0.87150838
12/29/2000	0.635	0.685	1.07874016
12/31/2001	0.93	0.4	0.43010753
12/31/2002	0.72	0.4	0.55555556
12/31/2003	1.03	0.4	0.38834951
12/31/2004	1.285	0.415	0.3229572
12/30/2005	1.305	0.44	0.33716475
12/29/2006	1.335	0.46	0.34456929
12/31/2007	1.415	0.5	0.35335689
12/31/2008	1.52	0.54	0.35526316
12/31/2009	1.62	0.675	0.41666667
12/31/2010	1.93	0.8	0.41450777
12/30/2011	2.24	1.04	0.46428571
12/31/2012	2.35	1.2	0.5106383
12/31/2013	2.51	1.445	0.57569721
12/31/2014	2.59	1.56	0.6023166
12/31/2015	2.34	1.74	0.74358974
12/30/2016	2.96	1.98	0.66891892
12/31/2017	3.79	2.08	0.54881266
		Median	0.58900691

XEL US Equity

Date	TRAIL_12M_DILUTED_EI	EQY_DPS	Payout %
12/31/1990	1.415	1.1475	0.81095406
12/31/1991	1.645	1.1975	0.72796353
12/31/1992	1.52	1.2475	0.82072368
12/31/1993	1.51	1.2825	0.84933775
12/30/1994	1.73	1.3125	0.75867052
12/29/1995	1.955	1.3425	0.68670077
12/31/1996	1.91	1.3725	0.71858639
12/31/1997	1.605	1.4025	0.87383178
12/31/1998	1.84	1.425	0.77445652
12/31/1999	1.7	1.445	0.85
12/29/2000	1.54	1.482	0.96233766
12/31/2001	2.3	1.5	0.65217391
12/31/2002	-5.82	1.125	-0.19329897
12/31/2003	1.5	0.75	0.5
12/31/2004	0.87	0.81	0.93103448
12/30/2005	1.23	0.8525	0.69308943
12/29/2006	1.36	0.8825	0.64889706
12/31/2007	1.35	0.91	0.67407407
12/31/2008	1.46	0.94	0.64383562
12/31/2009	1.48	0.97	0.65540541
12/31/2010	1.62	1	0.61728395
12/30/2011	1.72	1.03	0.59883721
12/31/2012	1.85	1.07	0.57837838
12/31/2013	1.91	1.11	0.58115183
12/31/2014	2.03	1.2	0.591133
12/31/2015	1.94	1.28	0.65979381
12/30/2016	2.21	1.36	0.61538462
12/31/2017	2.25	1.44	0.64
		Median	0.66693394

Market Charts

Market Charts

Period: Custom Metric: Price/LTM EPS (X)

Frequency: Daily

As Of
5/18/2018

Price/LTM EPS (X) - 5/16/2008 to 5/18/2018 - Daily

Pricing Date	*OTP ND Proxy*
5/18/2018	19.70
5/17/2018	19.70
5/16/2018	19.80
5/15/2018	19.90
5/14/2018	20.10
5/11/2018	20.30
5/10/2018	20.20
5/9/2018	20.20
5/8/2018	20.30
5/7/2018	20.70
5/4/2018	20.90
5/3/2018	20.80
5/2/2018	20.80
5/1/2018	21.10
4/30/2018	21.20
4/27/2018	21.30
4/26/2018	20.80
4/25/2018	20.50
4/24/2018	20.50
4/23/2018	20.30
4/20/2018	20.20
4/19/2018	20.20
4/18/2018	20.20
4/17/2018	20.40
4/16/2018	20.20
4/13/2018	19.80
4/12/2018	19.60
4/11/2018	19.80
4/10/2018	19.80
4/9/2018	19.90
4/6/2018	20.00
4/5/2018	20.10
4/4/2018	19.90
4/3/2018	19.90

30-day average
20.31

4/2/2018	19.80
3/29/2018	20.00
3/28/2018	19.90
3/27/2018	19.80
3/26/2018	19.60
3/23/2018	19.20
3/22/2018	19.50
3/21/2018	19.50
3/20/2018	19.50
3/19/2018	19.60
3/16/2018	19.60
3/15/2018	19.30
3/14/2018	19.20
3/13/2018	19.10
3/12/2018	19.20
3/9/2018	18.90
3/8/2018	18.80
3/7/2018	18.70
3/6/2018	18.80
3/5/2018	19.10
3/2/2018	18.90
3/1/2018	18.80
2/28/2018	18.80
2/27/2018	18.90
2/26/2018	17.90
2/23/2018	18.00
2/22/2018	17.60
2/21/2018	19.00
2/20/2018	19.20
2/16/2018	19.40
2/15/2018	19.30
2/14/2018	18.80
2/13/2018	18.90
2/12/2018	18.90
2/9/2018	18.80
2/8/2018	18.30
2/7/2018	18.50
2/6/2018	18.50
2/5/2018	18.80
2/2/2018	19.20
2/1/2018	19.30
1/31/2018	20.00
1/30/2018	19.80
1/29/2018	19.80
1/26/2018	20.10
1/25/2018	20.20

1/24/2018	19.90
1/23/2018	20.00
1/22/2018	19.70
1/19/2018	19.70
1/18/2018	19.70
1/17/2018	19.80
1/16/2018	19.60
1/12/2018	19.70
1/11/2018	19.80
1/10/2018	19.90
1/9/2018	20.30
1/8/2018	20.70
1/5/2018	20.50
1/4/2018	20.60
1/3/2018	20.70
1/2/2018	20.90
12/29/2017	21.20
12/28/2017	21.20
12/27/2017	21.00
12/26/2017	20.90
12/22/2017	21.10
12/21/2017	21.00
12/20/2017	21.10
12/19/2017	21.30
12/18/2017	21.70
12/15/2017	22.00
12/14/2017	21.80
12/13/2017	22.00
12/12/2017	21.90
12/11/2017	22.30
12/8/2017	22.30
12/7/2017	22.20
12/6/2017	22.20
12/5/2017	22.10
12/4/2017	22.40
12/1/2017	22.50
11/30/2017	22.60
11/29/2017	22.50
11/28/2017	22.40
11/27/2017	22.20
11/24/2017	22.10
11/22/2017	22.00
11/21/2017	22.20
11/20/2017	22.10
11/17/2017	22.20
11/16/2017	22.30

11/15/2017	22.20
11/14/2017	22.40
11/13/2017	22.00
11/10/2017	21.70
11/9/2017	21.90
11/8/2017	21.90
11/7/2017	21.90
11/6/2017	21.70
11/3/2017	21.80
11/2/2017	21.90
11/1/2017	22.00
10/31/2017	22.10
10/30/2017	22.00
10/27/2017	22.20
10/26/2017	22.20
10/25/2017	22.20
10/24/2017	22.30
10/23/2017	22.40
10/20/2017	22.40
10/19/2017	22.40
10/18/2017	22.30
10/17/2017	22.30
10/16/2017	22.10
10/13/2017	22.20
10/12/2017	22.20
10/11/2017	22.10
10/10/2017	22.00
10/9/2017	21.80
10/6/2017	21.70
10/5/2017	21.90
10/4/2017	21.90
10/3/2017	21.70
10/2/2017	21.80
9/29/2017	21.70
9/28/2017	21.80
9/27/2017	21.80
9/26/2017	21.90
9/25/2017	22.00
9/22/2017	21.70
9/21/2017	21.90
9/20/2017	21.90
9/19/2017	22.00
9/18/2017	22.00
9/15/2017	22.20
9/14/2017	22.20
9/13/2017	22.00

9/12/2017	22.10
9/11/2017	22.50
9/8/2017	22.40
9/7/2017	22.20
9/6/2017	22.10
9/5/2017	22.20
9/1/2017	22.10
8/31/2017	22.10
8/30/2017	22.10
8/29/2017	22.20
8/28/2017	22.30
8/25/2017	22.20
8/24/2017	22.10
8/23/2017	22.10
8/22/2017	22.10
8/21/2017	21.80
8/18/2017	21.70
8/17/2017	21.60
8/16/2017	21.80
8/15/2017	21.70
8/14/2017	21.70
8/11/2017	21.60
8/10/2017	21.70
8/9/2017	21.70
8/8/2017	21.80
8/7/2017	21.70
8/4/2017	21.60
8/3/2017	21.60
8/2/2017	22.30
8/1/2017	22.70
7/31/2017	22.50
7/28/2017	22.40
7/27/2017	22.70
7/26/2017	22.60
7/25/2017	22.60
7/24/2017	22.50
7/21/2017	22.80
7/20/2017	22.50
7/19/2017	22.20
7/18/2017	22.10
7/17/2017	22.00
7/14/2017	21.90
7/13/2017	21.90
7/12/2017	22.00
7/11/2017	21.80
7/10/2017	21.90

7/7/2017	22.00
7/6/2017	21.90
7/5/2017	22.00
7/3/2017	22.10
6/30/2017	22.10
6/29/2017	22.20
6/28/2017	22.50
6/27/2017	22.60
6/26/2017	22.90
6/23/2017	22.80
6/22/2017	22.80
6/21/2017	22.90
6/20/2017	23.00
6/19/2017	23.00
6/16/2017	23.20
6/15/2017	23.00
6/14/2017	22.90
6/13/2017	22.80
6/12/2017	22.70
6/9/2017	22.80
6/8/2017	22.80
6/7/2017	22.90
6/6/2017	22.90
6/5/2017	22.90
6/2/2017	23.10
6/1/2017	22.90
5/31/2017	22.70
5/30/2017	22.60
5/26/2017	22.50
5/25/2017	22.60
5/24/2017	22.40
5/23/2017	22.30
5/22/2017	22.10
5/19/2017	21.80
5/18/2017	21.80
5/17/2017	21.80
5/16/2017	21.70
5/15/2017	21.90
5/12/2017	21.90
5/11/2017	21.80
5/10/2017	21.80
5/9/2017	21.70
5/8/2017	22.00
5/5/2017	22.10
5/4/2017	21.90
5/3/2017	21.90

5/2/2017	23.50
5/1/2017	23.50
4/28/2017	23.70
4/27/2017	24.10
4/26/2017	24.10
4/25/2017	24.20
4/24/2017	24.20
4/21/2017	24.10
4/20/2017	23.90
4/19/2017	24.00
4/18/2017	24.20
4/17/2017	24.10
4/13/2017	23.90
4/12/2017	24.10
4/11/2017	24.00
4/10/2017	23.90
4/7/2017	23.90
4/6/2017	24.00
4/5/2017	24.00
4/4/2017	23.80
4/3/2017	23.70
3/31/2017	23.70
3/30/2017	23.70
3/29/2017	23.80
3/28/2017	23.90
3/27/2017	23.90
3/24/2017	23.90
3/23/2017	23.80
3/22/2017	23.70
3/21/2017	23.70
3/20/2017	23.50
3/17/2017	23.90
3/16/2017	23.60
3/15/2017	23.80
3/14/2017	23.40
3/13/2017	23.40
3/10/2017	23.30
3/9/2017	23.10
3/8/2017	23.10
3/7/2017	23.60
3/6/2017	23.50
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Currency data supplied by Interactive Data Pricing and Reference Data LLC

Rate Case History (Past Rate Cases)

Portfolio	None
Company List	All
States	All
Years	All
Service Type	Electric

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Rate Increase ($M)	Return on Original Cost Rate (%)	Return on Equity (%)	Common Equity to Total Capital (%)	Rate Base ($M)	Date	Decision Type	Rate Increase ($M)	Phase-in?	Interim Authorized?	Return on Original Cost Rate (%)	Return on Equity (%)	Common Equity to Total Capital (%)	Rate Case Test Year End Date	Rate Base ($M)	Rate Base Valuation Method	Rate Case Duration (months)
Vermont	Central Vermont Public Service		D-NA	Electric	Vertically Integrated	11/30/1979	5.3	10.80	14.50	39.30	NA	1/1/1980	Fully Litigated	5.3	No	No	10.80	14.50	39.30	09/1979	NA	NA	1
Ohio	Duke Energy Ohio Inc.	DUK	C-79-11-EL-AIR	Electric	Vertically Integrated	4/6/1979	104.0	11.09	16.50	36.70	NA	1/7/1980	Fully Litigated	35.1	No	No	10.24	14.39	35.80	09/1979	NA	NA	9
Texas	CenterPoint Energy Houston	CNP	D-2676	Electric	Vertically Integrated	7/2/1979	179.4	10.76	15.50	40.18	NA	1/8/1980	Fully Litigated	82.0	No	Yes	10.55	15.00	38.01	03/1979	NA	Year-end	6
Oregon	Portland General Electric Co.	POR	C-UF-3518	Electric	Vertically Integrated	6/1/1979	78.0	10.82	14.50	38.67	NA	1/14/1980	Fully Litigated	62.3	Yes	No	11.15	15.17	36.65	12/1980	NA	NA	7
Virginia	Appalachian Power Co.	AEP	C-PUE-790015	Electric	Vertically Integrated	11/9/1979	16.2	NA	13.93	38.60	NA	1/17/1980	Fully Litigated	11.1	No	Yes	9.98	13.93	NA	09/1979	NA	Year-end	2
Texas	AEP Texas Central Co.	AEP	D-2840	Electric	Vertically Integrated	10/1/1979	94.8	10.75	15.50	37.68	NA	1/23/1980	Fully Litigated	65.5	No	No	10.75	15.50	37.68	09/1979	928.00	Year-end	2
Ohio	Ohio Edison Co.	FE	C-78-1567&68-EL-AIR	Electric	Vertically Integrated	4/23/1979	149.6	10.46	14.50	39.00	NA	1/30/1980	Fully Litigated	117.4	No	No	10.12	13.86	34.54	09/1979	NA	NA	9
Massachusetts	Commonwealth Electric Co.	NST	DPU-20132-E	Electric	Vertically Integrated	7/17/1979	11.2	11.04	14.00	51.99	NA	1/31/1980	Fully Litigated	5.6	No	No	10.31	12.61	52.09	12/1979	NA	NA	6
Illinois	Commonwealth Edison Co.	EXC	D-79-0214	Electric	Vertically Integrated	4/6/1979	451.7	10.31	14.15	35.70	NA	2/6/1980	Fully Litigated	389.4	No	No	10.05	13.71	33.09	12/1979	NA	NA	10
South Dakota	Black Hills Power Inc.	BKH	D-F-3325	Electric	Vertically Integrated	10/17/1979	5.3	10.87	14.50	44.37	NA	2/13/1980	Fully Litigated	4.0	No	No	10.12	12.80	44.37	04/1979	NA	Average	3
Wisconsin	Madison Gas and Electric Co.	MGEE	D-3270-UR-9-E	Electric	Vertically Integrated	5/31/1979	10.1	NA	14.00	41.30	NA	2/14/1980	Fully Litigated	6.0	No	No	NA	13.00	40.00	12/1980	185.90	Average	8
Wisconsin	Wisconsin Power and Light Co	LNT	D-6680-UR-5	Electric	Vertically Integrated	7/8/1977	26.8	NA	14.50	38.10	NA	2/19/1980	Fully Litigated	21.8	No	Yes	NA	13.50	36.90	12/1978	NA	Average	31
Maryland	Delmarva Power & Light Co.	EXC	C-7363 0-64218	Electric	Vertically Integrated	8/2/1979	7.6	9.79	15.00	34.65	NA	2/27/1980	Fully Litigated	4.0	No	No	9.46	13.75	34.65	03/1979	NA	Average	6
Arkansas	Entergy Arkansas Inc.	ETR	D-U-2972	Electric	Vertically Integrated	10/23/1978	27.0	10.09	14.50	32.04	NA	2/29/1980	Fully Litigated	14.7	No	No	9.95	13.75	33.00	06/1978	NA	Year-end	16
New York	Niagara Mohawk Power Corp.	NG.	C-27538,39	Electric	Vertically Integrated	4/6/1979	135.5	10.14	14.00	38.24	NA	2/29/1980	Fully Litigated	122.6	No	No	10.22	14.00	38.50	03/1981	NA	Average	10
Ohio	Toledo Edison Co.	FE	C-79-143-EL-AIR	Electric	Vertically Integrated	5/22/1979	52.0	10.63	14.75	36.00	NA	2/29/1980	Fully Litigated	30.7	No	No	10.77	14.77	35.13	09/1979	NA	NA	9
Mississippi	Mississippi Power Co.	SO	C-U-3739	Electric	Vertically Integrated	9/10/1979	23.9	9.86	14.95	33.81	NA	3/7/1980	Fully Litigated	16.8	No	No	NA	12.70	33.81	10/1980	NA	Average	5
Michigan	DTE Electric Co.	DTE	C-U-6006	Electric	Vertically Integrated	12/14/1978	243.4	9.62	14.50	30.10	NA	3/14/1980	Fully Litigated	132.7	No	Yes	9.25	13.50	30.30	12/1979	NA	NA	15
Idaho	PacifiCorp	BRK.A	C-U-1009-107	Electric	Vertically Integrated	10/30/1979	27.9	10.81	15.00	40.00	NA	3/26/1980	Fully Litigated	16.3	No	No	10.50	14.16	37.50	12/1979	NA	NA	4
New York	Orange & Rockland Utils Inc.	ED	C-27553	Electric	Vertically Integrated	5/1/1979	11.6	9.92	13.75	39.30	NA	3/27/1980	Fully Litigated	11.6	No	No	10.12	14.24	39.25	03/1981	NA	Average	11
Idaho	Idaho Power Co.	IDA	C-U-1006-159	Electric	Vertically Integrated	12/28/1979	57.8	9.55	14.50	28.60	NA	3/28/1980	Fully Litigated	47.2	No	No	9.42	14.50	33.83	12/1979	NA	NA	3
Kentucky	Kentucky Power Co.	AEP	C-7489	Electric	Vertically Integrated	6/11/1979	13.3	11.10	14.50	40.30	NA	4/11/1980	Fully Litigated	1.5	No	No	10.20	12.75	41.68	03/1979	NA	Year-end	10
Maryland	Potomac Electric Power Co.	EXC	C-7384 0-64268	Electric	Vertically Integrated	9/17/1979	42.4	10.00	14.50	38.50	NA	4/14/1980	Fully Litigated	18.9	No	No	9.60	13.85	37.90	11/1979	NA	Average	7
New Mexico	Public Service Co. of NM	PNM	C-1536	Electric	Vertically Integrated	12/7/1979	16.7	9.83	15.50	34.60	NA	4/16/1980	Fully Litigated	11.0	No	No	9.83	15.50	34.60	12/1979	NA	Year-end	4
North Dakota	Otter Tail Power Co.	OTTR	C-9996	Electric	Vertically Integrated	8/16/1979	16.1	10.07	14.00	33.58	NA	4/22/1980	Fully Litigated	3.3	No	No	9.70	13.25	32.93	12/1980	NA	Average	8
North Carolina	Duke Energy Progress LLC	DUK	D-E-2, SUB 366	Electric	Vertically Integrated	8/31/1979	55.9	10.15	14.25	37.30	NA	4/22/1980	Fully Litigated	43.4	No	No	10.66	13.90	38.00	12/1978	NA	NA	7
Utah	PacifiCorp	BRK.A	C-79-035-12	Electric	Vertically Integrated	10/4/1979	33.5	10.87	15.00	40.00	NA	4/24/1980	Fully Litigated	46.1	No	No	11.64	16.80	36.93	09/1980	NA	Average	6
Texas	Oncor Electric Delivery Co.	SRE	D-3006	Electric	Vertically Integrated	1/4/1980	124.1	11.12	16.00	38.61	NA	4/29/1980	Fully Litigated	81.9	No	No	10.91	15.50	38.61	09/1979	NA	Year-end	3
New York	Long Island Lighting Co		C-27622	Electric	Vertically Integrated	9/21/1979	25.6	NA	13.70	NA	NA	5/6/1980	Fully Litigated	25.1	No	No	NA	13.70	NA	04/1981	NA	Average	7
Oklahoma	Public Service Co. of OK	AEP	Ca-26669	Electric	Vertically Integrated	6/22/1979	29.6	10.64	15.00	42.85	NA	5/7/1980	Fully Litigated	(15.1)	No	No	10.64	15.00	42.85	06/1979	NA	Year-end	10
New Jersey	Public Service Electric Gas	PEG	D-794-310-E	Electric	Vertically Integrated	4/2/1979	264.6	9.73	14.25	38.28	NA	5/8/1980	Fully Litigated	134.4	No	No	9.46	13.75	35.91	12/1979	NA	NA	13
Pennsylvania	PECO Energy Co.	EXC	C-R-79060865	Electric	Vertically Integrated	7/27/1979	122.7	10.42	14.50	35.10	NA	5/9/1980	Fully Litigated	88.8	No	No	10.51	14.38	35.00	03/1980	NA	Year-end	9
Rhode Island	Blackstone Valley Electric		D-1439-U-1010-8	Electric	Vertically Integrated	8/15/1979	4.0	12.56	13.50	30.60	NA	5/13/1980	Fully Litigated	3.6	No	No	12.60	13.60	30.64	03/1979	NA	NA	9
District of Columbia	Potomac Electric Power Co.	EXC	C-715 0-7135	Electric	Vertically Integrated	2/15/1979	48.1	10.00	14.50	36.80	NA	5/15/1980	Fully Litigated	35.5	No	No	9.38	13.25	36.00	06/1979	NA	Year-end	15
Louisiana	Southwestern Electric Power Co	AEP	D-U-14250	Electric	Vertically Integrated	5/25/1979	33.0	11.11	15.00	41.00	NA	5/19/1980	Fully Litigated	18.7	No	No	10.56	13.75	36.00	12/1979	NA	Average	12
West Virginia	Appalachian Power Co.	AEP	C-79-140-E-42T	Electric	Vertically Integrated	4/27/1979	61.2	10.56	15.00	32.50	NA	5/27/1980	Fully Litigated	37.7	Yes	Yes	10.60	13.62	33.00	03/1979	NA	Average	13
Colorado	Public Service Co. of CO	XEL	D-1420-De-C80-1039 (Elec.)	Electric	Vertically Integrated	3/26/1980	55.0	9.87	14.60	35.81	NA	5/27/1980	Fully Litigated	45.9	No	No	9.54	14.60	35.80	12/1979	NA	Year-end	2
Arizona	Arizona Public Service Co.	PNW	D-U-1345 De-51009-E	Electric	Vertically Integrated	11/2/1979	97.4	10.49	13.50	37.20	NA	5/29/1980	Fully Litigated	33.1	No	No	8.95	16.00	37.21	07/1979	NA	NA	6
Massachusetts	Western Massachusetts Electric	ES	DPU-20279	Electric	Vertically Integrated	11/16/1979	29.2	11.17	16.25	35.45	NA	5/30/1980	Fully Litigated	13.9	No	No	10.30	13.80	35.45	06/1979	NA	NA	6
Texas	Southwestern Public Service Co	XEL	D-3111	Electric	Vertically Integrated	2/28/1980	42.6	11.00	16.95	35.93	NA	6/2/1980	Settled	31.9	No	No	10.76	15.63	35.30	09/1979	NA	Year-end	3
New Hampshire	Public Service Co. of NH	ES	D-R79-187	Electric	Vertically Integrated	8/31/1979	19.3	13.08	18.00	34.24	NA	6/6/1980	Fully Litigated	18.3	No	Yes	12.49	15.90	34.24	05/1979	NA	NA	9
Maryland	Baltimore Gas and Electric Co.	EXC	C-7397 0-64331-E	Electric	Vertically Integrated	11/13/1979	123.0	10.06	14.70	38.90	NA	6/10/1980	Fully Litigated	73.9	No	No	9.63	13.78	38.50	01/1980	NA	Average	7
Pennsylvania	Pennsylvania Power Co.	FE	C-R-79121020	Electric	Vertically Integrated	11/16/1980	15.8	10.94	15.50	35.00	NA	6/12/1980	Settled	10.2	No	No	10.50	14.25	35.00	09/1979	411.80	Year-end	4
Missouri	Kansas City Power & Light	GXP	C-ER-80-48	Electric	Vertically Integrated	8/3/1979	70.0	10.73	15.00	36.90	NA	6/19/1980	Fully Litigated	45.7	No	No	10.16	13.40	34.28	12/1979	NA	Year-end	10
South Carolina	South Carolina Electric & Gas	SCG	D-79-196-E O-80-375	Electric	Vertically Integrated	6/1/1979	39.0	9.60	13.00	33.00	NA	6/30/1980	Fully Litigated	33.5	No	Yes	9.85	13.00	33.32	03/1979	NA	NA	13
West Virginia	Potomac Edison Co.	FE	C-79-230-E-42T	Electric	Vertically Integrated	6/29/1979	14.8	10.29	15.00	35.40	NA	6/30/1980	Fully Litigated	7.4	No	Yes	9.85	13.40	34.00	05/1979	NA	Average	12
Hawaii	Hawaiian Electric Co.	HE	D-3705	Electric	Vertically Integrated	8/16/1979	48.6	10.39	15.50	35.90	NA	7/9/1980	Fully Litigated	41.7	No	No	10.11	14.75	35.90	12/1980	NA	Average	10
Ohio	Cleveland Elec Illuminating Co	FE	C-79-537-EL-AIR	Electric	Vertically Integrated	9/17/1979	136.6	11.17	16.00	38.44	NA	7/10/1980	Fully Litigated	69.6	No	No	10.82	15.00	38.41	12/1979	NA	NA	9
Texas	Texas-New Mexico Power Co.	PNM	D-3093	Electric	Vertically Integrated	2/22/1980	5.7	11.42	16.50	35.56	NA	7/15/1980	Settled	3.9	No	No	11.15	15.80	35.58	09/1979	NA	Year-end	4
New York	Rochester Gas & Electric Corp.	IBE	C-27606,07	Electric	Vertically Integrated	8/24/1979	56.0	11.03	15.50	40.50	NA	7/18/1980	Fully Litigated	38.4	No	No	10.32	13.80	39.90	07/1981	NA	Average	10
New York	NY State Electric & Gas Corp.	IBE	C-27609	Electric	Vertically Integrated	8/28/1979	85.9	10.75	14.80	39.40	NA	7/22/1980	Fully Litigated	35.5	No	No	10.58	14.10	39.90	07/1981	NA	Average	10
New Mexico	El Paso Electric Co.	EE	C-1539	Electric	Vertically Integrated	4/25/1980	13.8	13.22	18.50	36.55	NA	7/24/1980	Fully Litigated	5.1	No	No	11.72	15.00	36.55	12/1979	NA	Year-end	3
Virginia	Potomac Edison Co.	FE	C-800060	Electric	Vertically Integrated	3/21/1980	4.2	9.57	13.48	30.50	NA	7/25/1980	Fully Litigated	4.2	No	No	9.57	13.48	30.50	12/1979	NA	Year-end	4
Ohio	Dayton Power and Light Co.	AES	C-79-510-EL-AIR	Electric	Vertically Integrated	10/19/1979	100.2	10.71	14.72	35.60	NA	7/31/1980	Fully Litigated	31.8	No	No	10.62	14.58	34.60	12/1979	NA	NA	9
Michigan	Consumers Energy Co.	CMS	C-U-5979	Electric	Vertically Integrated	1/29/1979	305.8	9.98	15.50	32.14	NA	8/8/1980	Fully Litigated	70.3	No	No	9.23	13.50	30.54	12/1980	NA	NA	19
Maine	Emera Maine	EMA	D-80-38	Electric	Vertically Integrated	2/25/1980	5.4	11.46	15.40	NA	NA	8/8/1980	Fully Litigated	4.7	No	No	10.65	14.00	32.20	12/1979	NA	NA	5
New Mexico	Southwestern Public Service Co	XEL	C-1567	Electric	Vertically Integrated	3/10/1980	9.2	11.00	16.95	35.90	NA	8/8/1980	Fully Litigated	6.2	No	No	10.49	15.45	34.92	09/1979	NA	Year-end	5
Idaho	Avista Corp.	AVA	C-U-1008-144	Electric	Vertically Integrated	3/17/1980	14.7	11.19	15.50	40.00	NA	8/11/1980	Fully Litigated	8.1	No	No	10.74	14.85	36.62	12/1979	NA	NA	4
Alabama	Alabama Power Co.	SO	D-17859	Electric	Vertically Integrated	12/28/1979	122.3	10.49	16.00	25.95	NA	8/14/1980	Settled	80.0	No	No	9.97	14.00	25.95	11/1979	NA	NA	7
Texas	El Paso Electric Co.	EE	D-3254	Electric	Vertically Integrated	5/22/1980	50.5	12.22	17.00	36.90	NA	8/14/1980	Settled	31.9	No	No	12.16	16.25	40.35	12/1979	286.40	Year-end	2
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-80-118	Electric	Vertically Integrated	10/5/1979	28.4	NA	15.00	30.00	NA	8/25/1980	Fully Litigated	9.2	No	No	9.66	13.75	27.40	12/1979	NA	Year-end	10
Indiana	Northern IN Public Svc Co.	NI	Ca-36007	Electric	Vertically Integrated	2/20/1980	71.0	10.15	14.00	38.40	NA	8/27/1980	Fully Litigated	65.6	No	No	9.93	13.80	36.40	12/1979	NA	Year-end	6
South Carolina	Duke Energy Carolinas LLC	DUK	D-79-300-E O-80-474	Electric	Vertically Integrated	8/1/1979	25.8	9.83	12.80	38.00	NA	8/29/1980	Fully Litigated	23.4	No	Yes	10.21	12.50	35.37	06/1979	NA	NA	13
Virginia	Virginia Electric & Power Co.	D	C-PUE 800056	Electric	Vertically Integrated	3/31/1980	72.6	9.86	13.50	31.01	NA	9/15/1980	Fully Litigated	60.0	No	No	9.79	13.50	31.01	12/1979	NA	Year-end	5
Virginia	Appalachian Power Co.	AEP	C-PUE 800039	Electric	Vertically Integrated	7/14/1980	23.6	10.31	13.93	31.50	NA	9/15/1980	Fully Litigated	22.3	No	Yes	10.27	13.93	32.30	12/1979	NA	Year-end	2
Texas	CenterPoint Energy Houston	CNP	D-3320	Electric	Vertically Integrated	6/30/1980	214.4	11.38	16.00	42.76	NA	9/15/1980	Settled	134.9	No	No	11.32	15.80	38.80	03/1980	NA	Year-end	2
Iowa	MidAmerican Energy Co.	BRK.A	D-RPU-78-12	Electric	Vertically Integrated	3/29/1978	15.8	9.76	13.50	36.50	NA	9/24/1980	Fully Litigated	15.8	No	No	9.42	12.50	37.80	12/1979	NA	Average	30
Kentucky	Louisville Gas & Electric Co.	PPL	C-7799 (elec.)	Electric	Vertically Integrated	3/31/1980	49.0	10.49	15.90	34.27	NA	9/24/1980	Fully Litigated	43.7	No	No	10.14	15.00	36.43	01/1980	NA	Year-end	5
New Jersey	Atlantic City Electric Co.	EXC	D-7911-951	Electric	Vertically Integrated	11/30/1979	78.6	10.47	14.50	39.70	NA	9/26/1980	Fully Litigated	50.8	No	No	10.15	13.75	39.10	09/1980	NA	NA	10
North Carolina	Duke Energy Carolinas LLC	DUK	D-E-7, SUB 289	Electric	Vertically Integrated	2/29/1980	91.6	11.03	15.00	38.00	NA	9/30/1980	Fully Litigated	57.5	No	No	10.88	14.10	38.00	12/1979	NA	NA	7
Massachusetts	NSTAR Electric Co.	ES	DPU-160	Electric	Vertically Integrated	3/14/1980	68.9	11.20	16.00	32.93	NA	9/30/1980	Fully Litigated	42.7	No	No	10.81	14.20	32.93	12/1979	NA	Year-end	6
Kentucky	Kentucky Utilities Co.	PPL	C-7804	Electric	Vertically Integrated	4/7/1980	30.1	10.51	14.43	34.40	NA	10/1/1980	Fully Litigated	27.7	No	No	10.28	13.90	34.40	01/1980	NA	Year-end	5
Texas	Oncor Electric Delivery Co.	SRE	D-3250	Electric	Vertically Integrated	5/15/1980	157.8	12.20	17.50	39.58	NA	10/3/1980	Fully Litigated	69.4	Yes	Yes	11.31	15.50	39.58	03/1980	NA	Year-end	4
Iowa	MidAmerican Energy Co.	BRK.A	D-RPU-78-49	Electric	Vertically Integrated	12/15/1978	12.2	10.50	15.00	37.16	NA	10/7/1980	Fully Litigated	12.2	No	No	9.76	12.50	37.16	03/1980	NA	Average	22
Wisconsin	Wisconsin Electric Power Co.	WEC	D-6630-ER-10	Electric	Vertically Integrated	8/24/1979	71.8	NA	13.25	NA	NA	10/9/1980	Fully Litigated	71.0	Yes	Yes	NA	13.25	38.43	12/1980	NA	Average	13
Connecticut	Connecticut Light & Power Co.	ES	D-80-04-03-E	Electric	Vertically Integrated	5/5/1980	102.0	11.13	17.00	35.12	NA	10/9/1980	Fully Litigated	72.3	No	No	10.25	14.50	35.12	12/1979	NA	NA	5
Connecticut	Connecticut Light & Power Co.	ES	D-80-04-04-E	Electric	Vertically Integrated	5/5/1980	62.3	11.41	17.00	37.10	NA	10/9/1980	Fully Litigated	40.5	No	No	10.49	14.50	37.10	12/1979	NA	NA	5
Texas	Entergy Texas Inc.	ETR	D-3298	Electric	Vertically Integrated	6/17/1980	84.8	11.58	17.25	34.84	NA	10/16/1980	Settled	44.0	No	No	11.24	16.10	30.34	12/1979	NA	Year-end	4
Florida	Tampa Electric Co.	EMA	D-800011-EU	Electric	Vertically Integrated	2/18/1980	50.7	8.62	15.00	34.88	NA	10/17/1980	Fully Litigated	31.0	No	Yes	8.40	14.50	32.04	12/1979	NA	NA	8
Maine	Central Maine Power Co.	IBE	D-80-25, 66	Electric	Vertically Integrated	2/1/1980	36.9	11.56	15.00	35.70	NA	10/31/1980	Fully Litigated	16.2	No	No	10.78	13.75	35.70	12/1979	NA	NA	9
Massachusetts	Massachusetts Electric Co.	NG.	DPU-200	Electric	Vertically Integrated	4/16/1980	33.3	9.86	16.50	35.12	NA	10/31/1980	Fully Litigated	16.9	No	No	9.07	14.25	35.12	12/1979	NA	NA	6
Nevada	Sierra Pacific Power Co.	BRK.A	D-2856	Electric	Vertically Integrated	4/30/1980	16.1	12.54	15.50	37.35	NA	11/4/1980	Fully Litigated	6.2	No	No	10.99	15.00	37.35	12/1979	NA	Year-end	6
Washington	PacifiCorp	BRK.A	Ca-U-80-36, 68	Electric	Vertically Integrated	4/18/1980	18.8	10.78	14.80	29.60	NA	11/5/1980	Fully Litigated	15.9	No	No	10.10	13.75	31.90	12/1979	NA	Average	6

Date of Electric Rate Case	Return on Equity (%)	20 Year Treasury (%)	Risk Premium	LN(30-Year Treasury)
1/1/1980	14.50%	9.35%	5.14%	-2.36894928
1/7/1980	14.39%	9.38%	5.01%	-2.366233344
1/9/1980	15.00%	9.40%	5.60%	-2.364902084
1/14/1980	15.17%	9.42%	5.75%	-2.362796987
1/17/1980	13.93%	9.44%	4.49%	-2.36054265
1/23/1980	15.50%	9.47%	6.03%	-2.356993761
1/30/1980	13.86%	9.52%	4.34%	-2.351717566
1/31/1980	12.61%	9.53%	3.08%	-2.350662511
2/6/1980	13.71%	9.58%	4.13%	-2.345607423
2/13/1980	12.80%	9.63%	3.17%	-2.340017007
2/14/1980	13.00%	9.65%	3.35%	-2.338580214
2/19/1980	13.50%	9.68%	3.82%	-2.335294252
2/27/1980	13.75%	9.78%	3.97%	-2.324641558
2/29/1980	13.75%	9.81%	3.94%	-2.325179347
2/29/1980	14.00%	9.81%	4.19%	-2.325179347
2/29/1980	14.77%	9.81%	4.96%	-2.325179347
3/7/1980	12.70%	9.89%	2.81%	-2.3134561
3/14/1980	13.50%	9.97%	3.53%	-2.305740065
3/26/1980	14.16%	10.10%	4.06%	-2.292684268
3/27/1980	14.24%	10.12%	4.12%	-2.290903588
3/28/1980	14.50%	10.13%	4.37%	-2.289205007
4/1/1980	12.75%	10.27%	2.48%	-2.275582954
4/14/1980	13.85%	10.29%	3.56%	-2.274342691
4/16/1980	15.50%	10.31%	5.19%	-2.272099536
4/22/1980	13.25%	10.35%	2.90%	-2.267951809
4/22/1980	13.90%	10.35%	3.55%	-2.267951809
4/24/1980	16.80%	10.38%	6.43%	-2.26577112
4/29/1980	15.50%	10.41%	5.09%	-2.262715552
5/6/1980	13.70%	10.45%	3.25%	-2.258894047
5/7/1980	15.00%	10.45%	4.55%	-2.258309868
5/8/1980	13.75%	10.46%	3.29%	-2.25766431
5/9/1980	14.35%	10.47%	3.88%	-2.25696662
5/13/1980	13.60%	10.48%	3.12%	-2.255963344
5/15/1980	13.25%	10.49%	2.76%	-2.254342688
5/19/1980	13.75%	10.51%	3.24%	-2.252823972
5/27/1980	13.62%	10.54%	3.08%	-2.249703311
5/27/1980	14.60%	10.54%	4.06%	-2.249703311
5/29/1980	16.00%	10.55%	5.44%	-2.248409457
5/30/1980	13.80%	10.55%	3.24%	-2.247737124
6/2/1980	15.63%	10.57%	5.06%	-2.247036864
6/6/1980	15.90%	10.60%	5.30%	-2.244490728
6/10/1980	13.78%	10.60%	3.18%	-2.244056785
6/12/1980	14.25%	10.61%	3.64%	-2.243392084
6/19/1980	13.40%	10.62%	2.78%	-2.242195793
6/30/1980	13.00%	10.65%	2.35%	-2.2400611
6/30/1980	13.40%	10.65%	2.75%	-2.2400611
7/9/1980	14.75%	10.67%	4.08%	-2.237387414
7/10/1980	15.00%	10.68%	4.32%	-2.236895672
7/15/1980	15.80%	10.70%	5.10%	-2.235286322
7/18/1980	13.80%	10.71%	3.09%	-2.233987633
7/22/1980	14.10%	10.72%	3.38%	-2.233184971
7/24/1980	15.00%	10.73%	4.27%	-2.232341005
7/25/1980	13.48%	10.73%	2.75%	-2.231879488
7/31/1980	14.58%	10.75%	3.83%	-2.23015746
8/8/1980	13.50%	10.78%	2.72%	-2.22770028
8/8/1980	14.00%	10.78%	3.22%	-2.22770028
8/8/1980	15.45%	10.78%	4.67%	-2.22770028
8/11/1980	14.85%	10.78%	4.07%	-2.227347759
8/14/1980	14.00%	10.78%	3.21%	-2.226420665
8/14/1980	16.25%	10.78%	5.46%	-2.226420665
8/25/1980	13.75%	10.82%	2.93%	-2.223820124
8/27/1980	13.80%	10.83%	2.97%	-2.223141026
8/29/1980	12.50%	10.84%	1.66%	-2.222199367
9/15/1980	13.50%	10.88%	2.62%	-2.218363437
9/15/1980	13.93%	10.88%	3.05%	-2.218363437
9/15/1980	15.80%	10.88%	4.92%	-2.218363437
9/24/1980	12.50%	10.93%	1.57%	-2.213905941
9/24/1980	15.00%	10.93%	4.07%	-2.213905941
9/26/1980	13.75%	10.94%	2.81%	-2.212415375
9/30/1980	14.10%	10.96%	3.14%	-2.210986337
9/30/1980	14.20%	10.96%	3.24%	-2.210986337
10/1/1980	13.90%	10.97%	2.93%	-2.2102931
10/3/1980	15.50%	10.98%	4.52%	-2.20904468
10/7/1980	12.50%	10.99%	1.51%	-2.207979707
10/9/1980	13.25%	11.00%	2.25%	-2.206956782
10/9/1980	14.50%	11.00%	3.50%	-2.206956782
10/9/1980	14.50%	11.00%	3.50%	-2.206956782
10/16/1980	16.10%	11.02%	5.08%	-2.20507731
10/17/1980	14.50%	11.03%	3.47%	-2.204528688
10/31/1980	13.75%	11.11%	2.64%	-2.197572138
10/31/1980	14.25%	11.11%	3.14%	-2.197572138
11/4/1980	15.00%	11.12%	3.88%	-2.196784674
11/5/1980	13.75%	11.13%	2.62%	-2.19599783

SUMMARY OUTPUT

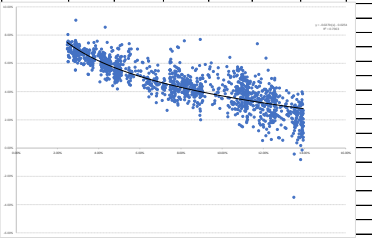
Regression Statistics

Multiple R	0.85809974
R Square	0.736335165
Adjusted R Square	0.736165168
Standard Error	0.008425601
Observations	1553

ANOVA

	df	SS	MS	F	Significance F
Regression	1	0.307494198	0.307494198	4331.468162	0
Residual	1551	0.110106662	7.09908E-05		
Total	1552	0.41760086			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	-0.025420004	0.001110423	-22.8821792	3.69888E-100	-0.027598093	-0.023241915	-0.027598093	-0.023241915
LN(30-Year Treasury)	-0.027083687	0.000411519	-65.81389034	0	-0.02789088	-0.026276494	-0.02789088	-0.026276494


y = -0.0274x - 2.3464
R² = 0.7363
0.00%
-2.00%
-4.

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Missouri	Union Electric Co.	AEE	C-ER-80-17	Electric	Vertically Integrated	7/8/1979	55.6	10.15	15.00	34.26	NA	4/24/1980	Fully Litigated	20.5	No	No	NA	NA	NA	03/1980	NA	NA	9																															
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-80-53	Electric	Vertically Integrated	8/8/1979	14.7	10.94	13.50	35.00	NA	4/25/1980	Fully Litigated	9	No	No	NA	NA	NA	04/1980	NA	Year-end	8																															
Missouri	Empire District Electric Co.	AQN	C-ER-80-143	Electric	Vertically Integrated	11/9/1979	16.1	NA	15.60	34.40	NA	7/29/1980	Fully Litigated	7.0	No	No	NA	NA	NA	03/1980	NA	NA	8																															
South Dakota	Northern States Power Co. - MN	XEL	D-F-3353	Electric	Vertically Integrated	6/23/1980	5.1	10.56	15.50	41.66	NA	11/19/1980	Fully Litigated	2.4	No	No	NA	NA	NA	12/1979	NA	Average	4																															
Maryland	Baltimore Gas and Electric Co.	EXC	C-7482 0-65066-E	Electric	Vertically Integrated	9/22/1980	29.5	9.55	NA	NA	NA	12/22/1980	Fully Litigated	19.0	No	No	9.55	NA	NA	08/1980	NA	Average	3																															
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-81-85	Electric	Vertically Integrated	9/5/1980	29.2	10.51	15.75	30	NA	5/27/1981	Fully Litigated	19.7	No	No	NA	NA	NA	05/1981	NA	NA	8																															
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-81-43	Electric	Vertically Integrated	7/24/1980	11.7	10.92	14	27.52	NA	6/8/1981	Fully Litigated	4.9	No	No	NA	NA	NA	12/1980	NA	Year-end	10																															
Missouri	Union Electric Co.	AEE	C-ER-81-180	Electric	Vertically Integrated	11/26/1980	91.1	10.88	15.50	36.07	NA	7/13/1981	Fully Litigated	50.0	No	No	NA	NA	NA	06/1981	NA	NA	7																															
Ohio	Ohio Edison Co.	FE	C-81-898-EL-AIR	Electric	Vertically Integrated	3/4/1981	139.2	12.22	17.5	36.19	NA	7/31/1981	Fully Litigated	90.0	No	No	NA	NA	NA	NA	NA	NA	4																															
Missouri	Empire District Electric Co.	AQN	C-ER-81-209	Electric	Vertically Integrated	12/19/1980	15.3	11.80	18.00	38.20	NA	8/18/1981	Fully Litigated	11.6	No	No	NA	NA	NA	03/1981	NA	NA	8																															
Tennessee	Kingsport Power Company	AEP	D-U-7022	Electric	Vertically Integrated	12/31/1980	8.5	13.78	15	39	NA	8/21/1981	Fully Litigated	6.7	No	No	12.48	NA	NA	06/1980	NA	Average	7																															
Alabama	Alabama Power Co.	SO	D-18117	Electric	Vertically Integrated	3/19/1981	324.9	11.59	18.00	27.50	NA	10/16/1981	Fully Litigated	186.0	No	No	NA	NA	NA	NA	NA	NA	7																															
Missouri	Union Electric Co.	AEE	C-ER-81-304	Electric	Vertically Integrated	1/2/1981	12.0	10.68	16.25	35.45	NA	12/3/1981	Fully Litigated	6.7	No	No	NA	NA	NA	02/1982	NA	NA	11																															
Pennsylvania	PPL Electric Utilities Corp.	PPL	C-R-811636	Electric	Vertically Integrated	8/28/1981	118.9	12.75	17.50	33.30	NA	12/18/1981	Settled	78.0	No	No	NA	NA	NA	04/1982	NA	Year-end	3																															
Pennsylvania	Metropolitan Edison Co.	FE	C-R-811601	Electric	Vertically Integrated	6/30/1981	166.2	11.83	19.00	35.08	NA	1/8/1982	Settled	112.0	No	No	NA	NA	NA	03/1982	NA	Year-end	6																															
Pennsylvania	Pennsylvania Electric Co.	FE	C-R-811602	Electric	Vertically Integrated	6/30/1981	92.6	11.45	18.00	33.28	NA	1/8/1982	Settled	64.7	No	No	NA	NA	NA	03/1982	NA	Year-end	6																															
Pennsylvania	West Penn Power Co.	FE	C-R-811836	Electric	Vertically Integrated	2/26/1982	93.9	11.76	18.00	36.50	NA	7/30/1982	Settled	48.9	No	No	NA	NA	NA	10/1982	NA	Year-end	5																															
Alabama	Alabama Power Co.	SO	D-18416	Electric	Vertically Integrated	3/6/1982	456.0	11.00	17.30	26.84	NA	10/12/1982	Fully Litigated	120.0	No	No	NA	NA	NA	NA	NA	NA	7																															
West Virginia	Wheeling Power Co.	AEP	C-82-334-E-42T	Electric	Vertically Integrated	8/12/1982	5.9	16.05	17.50	41.69	NA	5/8/1983	Settled	0.5	No	No	13.2	NA	NA	09/1983	NA	Average	9																															
Missouri	Union Electric Co.	AEE	C-ER-83-163	Electric	Vertically Integrated	12/3/1982	121.7	12.91	18.16	35.92	NA	7/6/1983	Settled	30.5	No	No	NA	NA	NA	06/1983	NA	NA	7																															
Pennsylvania	Duquesne Light Co.		C-R-832337	Electric	Vertically Integrated	4/29/1983	49.9	12.28	17.00	37.40	NA	9/16/1983	Settled	21.0	No	No	NA	NA	NA	12/1983	177.4.8	Year-end	4																															
Ohio	Cleveland Elec Illuminating Co	FE	C-83-849-EL-COI	Electric	Vertically Integrated	6/22/1983	0.0	NA	NA	NA	NA	9/21/1983	Settled	(13.5)	No	No	NA	NA	NA	12/1983	NA	NA	3																															
Vermont	Central Vermont Public Service		D-4797	Electric	Vertically Integrated	4/27/1983	11.1	13.24	16.60	46.10	NA	9/22/1983	Settled	4.6	No	No	NA	NA	NA	NA	NA	NA	2																															
Ohio	Ohio Power Co.	AEP	C-83-98-EL-AIR	Electric	Vertically Integrated	2/28/1983	82.2	12.77	17.80	34.30	NA	11/23/1983	Settled	74.5	No	No	11.35	NA	NA	NA	NA	NA	8																															
Wyoming	PacifiCorp	BRK-A	D-9454, Sub 20	Electric	Vertically Integrated	6/28/1983	18.4	12.78	17.10	36.00	NA	12/15/1983	Settled	4.0	No	No	NA	NA	NA	12/1982	NA	Year-end	5																															
Utah	PacifiCorp	BRK-A	C-83-035-06	Electric	Vertically Integrated	6/3/1983	76.6	12.46	15.80	42.13	NA	1/30/1984	Settled	35.0	No	Yes	NA	NA	NA	05/1984	NA	NA	8																															
Maryland	Baltimore Gas and Electric Co.	EXC	C-7770 0-66671-E	Electric	Vertically Integrated	11/2/1983	108.6	11.42	16.00	42.20	2,856.50	5/29/1984	Fully Litigated	58.5	No	No	10.96	NA	NA	12/1983	2869.8	Average	6																															
Pennsylvania	Metropolitan Edison Co.	FE	C-R-832549	Electric	Vertically Integrated	1/25/1984	19.8	11.17	16.50	40.18	NA	6/22/1984	Settled	8.2	No	No	NA	NA	NA	09/1984	NA	Year-end	4																															
District of Columbia	Potomac Electric Power Co.	EXC	C-813 0-8056, 8127	Electric	Vertically Integrated	11/4/1983	86.0	11.60	16.50	44.04	NA	7/12/1984	Settled	29.9	Yes	No	NA	NA	NA	12/1983	NA	Average	8																															
Massachusetts	Massachusetts Electric Co.	NG	DPU-84-240	Electric	Vertically Integrated	11/15/1984	(10.0)	NA	NA	NA	NA	11/16/1984	Settled	(10.0)	Yes	No	NA	NA	NA	NA	NA	NA	0																															
Massachusetts	Fitchburg Gas & Electric Light	UTL	DPU-84-145-E	Electric	Vertically Integrated	7/16/1984	6.9	15.57	18.00	37.16	NA	1/31/1985	Settled	2.2	No	No	NA	NA	NA	12/1983	NA	NA	6																															
Louisiana	Entergy Louisiana LLC	ETR	D-U-16091	Electric	Vertically Integrated	4/12/1984	591.7	12.82	16.00	37.00	2,902.30	3/5/1985	Fully Litigated	0.0	No	No	NA	NA	NA	09/1984	2541.2	Average	10																															
Louisiana	Entergy New Orleans LLC	ETR	D-U-16092 (elec.)	Electric	Vertically Integrated	4/12/1984	133.8	12.45	15	37	NA	3/5/1985	Fully Litigated	0.0	No	No	NA	NA	NA	09/1984	NA	Average	10																															
Louisiana	Entergy Louisiana LLC	ETR	D-U-16518	Electric	Vertically Integrated	5/17/1985	576.0	12.75	16.00	37.00	NA	7/30/1985	Fully Litigated	0.0	No	No	NA	NA	NA	NA	NA	NA	2																															
West Virginia	Potomac Edison Co.	FE	C-84-857-E-42T	Electric	Vertically Integrated	12/6/1984	10.5	11.47	16.00	39.65	NA	10/2/1985	Settled	1.4	No	No	NA	NA	NA	12/1984	NA	Average	10																															
Louisiana	Entergy Louisiana LLC	ETR	D-U-16945	Electric	Vertically Integrated	9/23/1985	444.4	12.75	16	37	NA	11/19/1985	Settled	383.0	Yes	Yes	NA	NA	NA	06/1984	NA	Average	1																															
Wyoming	PacifiCorp	BRK-A	D-9454, SUB 26	Electric	Vertically Integrated	10/3/1985	17.2	11.57	14.68	36.00	NA	12/12/1985	Fully Litigated	7.0	No	No	NA	NA	NA	NA	NA	NA	2																															
Texas	Southwestern Public Service Co	XEL	D-6465	Electric	Vertically Integrated	8/30/1985	(0.1)	11.55	15.05	44.29	NA	2/19/1986	Settled	(4.4)	No	No	11.70	NA	NA	06/1985	NA	Year-end	5																															
Indiana	Duke Energy Indiana, LLC	DUK	Ca-37414	Electric	Vertically Integrated	2/11/1985	76.7	13.15	20	35.93	1,862.00	3/7/1986	Settled	68.2	No	Yes	14.79	NA	NA	03/1984	1603.5	Year-end	12																															
Louisiana	Entergy New Orleans LLC	ETR	D-CD-85-1 (elec.)	Electric	Vertically Integrated	5/17/1985	118.0	12.75	16	37	NA	3/25/1986	Settled	60.0	Yes	Yes	NA	NA	NA	06/1984	NA	Average	10																															
Louisiana	Cleco Power LLC		D-U-16510	Electric	Vertically Integrated	5/10/1985	84.7	12.49	15.9	42	690.70	5/1/1986	Fully Litigated	0.0	No	No	NA	NA	NA	06/1985	NA	Average	11																															
Wyoming	PacifiCorp	BRK-A	D-9441, SUB 25	Electric	Vertically Integrated	12/23/1985	24.1	12.39	15.41	44.09	NA	6/2/1986	Settled	9.3	No	No	NA	NA	NA	06/1985	NA	Year-end	5																															
Louisiana	Entergy Gulf States LA LLC	ETR	D-U-16950	Electric	Vertically Integrated	9/30/1985	454.0	13.42	16.5	40	NA	6/4/1986	Fully Litigated	0.0	No	No	NA	NA	NA	12/1984	NA	Average	8																															
Maine	Central Maine Power Co.	IBE	D-85-212	Electric	Vertically Integrated	12/20/1985	48.8	12.1	14.5	NA	NA	7/8/1986	Settled	32.4	No	Yes	NA	NA	NA	06/1985	NA	NA	6																															
Mississippi	Mississippi Power Co.	SO	C-U-4761	Electric	Vertically Integrated	11/5/1985	0.0	NA	NA	NA	NA	8/7/1986	Fully Litigated	0.0	No	No	NA	NA	NA	NA	NA	NA	9																															
Vermont	Green Mountain Power Corp.		D-5125	Electric	Vertically Integrated	3/17/1986	6.3	12.72	15.5	43.8	NA	9/12/1986	Fully Litigated	(1.0)	No	No	NA	NA	NA	12/1985	NA	Average	5																															
Maryland	Delmarva Power & Light Co.	EXC	C-7971 0-67487	Electric	Vertically Integrated	6/26/1986	NA	NA	NA	NA	NA	10/2/1986	Settled	(5.6)	No	No	10.88	NA	NA	NA	NA	NA	3																															
Texas	Entergy Texas Inc.	ETR	D-6525	Electric	Vertically Integrated	10/1/1985	296.0	13.33	16.5	38	NA	10/15/1986	Settled	(80.0)	No	No	NA	NA	NA	12/1985	NA	Year-end	12																															
Pennsylvania	Metropolitan Edison Co.	FE	C-R-860384	Electric	Vertically Integrated	6/10/1986	57.7	10.76	14.75	43.10	NA	11/25/1986	Settled	38.0	No	No	NA	NA	NA	NA	NA	NA	5																															
Pennsylvania	Pennsylvania Electric Co.	FE	C-R-860413	Electric	Vertically Integrated	6/10/1986	38.1	10.94	14.50	45.16	NA	11/25/1986	Settled	14.0	No	No	NA	NA	NA	NA	NA	NA	5																															
Oregon	PacifiCorp	BRK-A	C-UE-52	Electric	Vertically Integrated	6/16/1986	22.6	NA	NA	NA	NA	1/8/1987	Settled	15.3	Yes	No	NA	NA	NA	NA	NA	NA	6																															
Connecticut	United Illuminating Co.	IBE	D-87-01-04	Electric	Vertically Integrated	1/6/1987	NA	NA	NA	NA	NA	4/14/1987	Settled	NA	No	No	NA	NA	NA	12/1987	NA	NA	3																															
Indiana	Indiana Michigan Power Co.	AEP	Ca-38063-S1	Electric	Vertically Integrated	7/11/1986	11.7	NA	NA	NA	NA	8/8/1987	Fully Litigated	0.0	No	No	NA	NA	NA	NA	NA	NA	14																															
Massachusetts	Eastern Edison Company		DPU-88-100	Electric	Vertically Integrated	6/14/1988	11.9	11.55	13.25	41.5	NA	12/30/1988	Settled	7.5	No	No	NA	NA	NA	12/1987	NA	NA	6																															
Ohio	Cleveland Elec Illuminating Co	FE	C-88-170-EL-AIR	Electric	Vertically Integrated	3/8/1988	452.8	11.75	14.00	NA	NA	1/31/1989	Settled	324.8	Yes	No	NA	NA	NA	11/1988	NA	NA	10																															
Ohio	Toledo Edison Co.	FE	C-88-171-EL-AIR	Electric	Vertically Integrated	3/8/1988	194.6	11.75	14.00	40.45	NA	1/31/1989	Settled	135.7	Yes	No	NA	NA	NA	11/1988	NA	NA	10																															
Louisiana	Entergy Louisiana LLC	ETR	D-CD-86-11,CD-89-1	Electric	Vertically Integrated	7/11/1986	13.8	12.54	15.28	40	NA	7/6/1989	Settled	9.5	Yes	No	NA	NA	NA	12/1986	NA	Average	36																															
Nevada	Sierra Pacific Power Co.	BRK-A	D-89-516	Electric	Vertically Integrated	5/5/1989	1.9	10.95	14	42.35	NA	9/26/1989	Settled	(11.0)	No	No	NA	NA	NA	12/1988	NA	NA	4																															
Massachusetts	NSTAR Electric Co.	ES	DPU-89-100	Electric	Vertically Integrated	4/14/1989	85.8	11.18	13.75	39.57	NA	10/31/1989	Settled	NA	No	No	NA	NA	NA	NA	NA	NA	8																															
Maine	Central Maine Power Co.	IBE	D-89-68	Electric	Vertically Integrated	5/19/1989	61.5	11.37	14.00	41.13	NA	12/15/1989	Settled	39.0	No	No	NA	NA	NA	12/1988	NA	NA	7																															
Massachusetts	Cambridge Electric Light Co	NST	DPU-89-109	Electric	Vertically Integrated	5/17/1989	6.1	12.09	15	50.3	NA	12/18/1989	Settled	4.4	No	No	NA	NA	NA	12/1988	NA	NA	7																															
Maryland	Potomac Electric Power Co.	EXC	C-8251	Electric	Vertically Integrated	2/1/1990	24.0	10.11	13.00	43.16	NA	5/29/1990	Settled	13.8	No	No	NA	NA	NA	NA	NA	NA	3																															
Minnesota	Northern States Power Co. - MN	XEL	D-E-002-GR-89-865	Electric	Vertically Integrated	11/2/1989	120.8	10.20	13.25	47.03	NA	8/6/1990	Fully Litigated	0.0	No	Yes	NA	NA	NA	NA	NA	NA	9																															
Missouri	Empire District Electric Co.	AQN	C-ER-90-138	Electric	Vertically Integrated	12/29/1989	8.2	11.07	13.50	48.90	NA	8/31/1990	Fully Litigated	5.7	No	No	NA	NA	NA	NA	NA	NA	8																															
Maine	Emera Maine	EMA	D-90-001	Electric	Vertically Integrated	3/9/1990	9.1	11.87	14.10	40.00	NA	9/17/1990	Fully Litigated	1.6	No	Yes	NA	NA	NA	12/1989	NA	Average	6																															
Texas	AEP Texas Central Co.	AEP	D-9561	Electric	Vertically Integrated	5/17/1990	120.0	11.13	13.00	44.80	NA	12/19/1990	Settled	120.0	No	No	NA	NA	NA	12/1989	NA	Year-end	7																															
Texas	Entergy Texas Inc.	ETR	D-8702	Electric	Vertically Integrated	3/21/1989	103.0	12.52	15	39.11	NA	3/22/1991	Settled	30.0	No	Yes	NA	NA	NA	09/1988	NA	Year-end	24																															
Washington	Puget Sound Energy Inc.		Ca-UE-90-1183-T,84-P	Electric	Vertically Integrated	11/5/1990	19.2	NA	NA	NA	NA	4/1/1991	Fully Litigated	0.0	No	No	NA	NA	NA	NA	NA	NA	4																															
Massachusetts	Western Massachusetts Electric	ES	DPU-90-300	Electric	Vertically Integrated	12/14/1990	54.9	10.67	13.70	37.45	NA	7/1/1991	Settled	32.2	No	No	NA	NA	NA	06/1990	NA	Year-end	6																															
Colorado	Public Service Co. of CO	XEL	D-91S-091E	Electric	Vertically Integrated	1/31/1991	(23.6)	10.68	13.75	47.84	NA	7/3/1991	Settled	(36.0)	No	No	NA	NA	NA	NA	NA	NA	5																															
Massachusetts	Massachusetts Electric Co.	NG	DPU-91-52	Electric	Vertically Integrated	3/15/1991	35.6	10.65	13.50	46.54	NA	9/6/1991	Settled	17.0	No	No	NA	NA	NA	12/1990	NA	Year-end	5																															
Arizona	Tucson Electric Power Co.	FTS	D-U-1933-90-270	Electric	Vertically Integrated	9/21/1990	50.4	10.32	13.5	40	NA	10/11/1991	Settled	71.0	No	No	7.87	NA	NA	06/1990	NA	Year-end	12																															
Arizona	Arizona Public Service Co.	PNW	D-U-1345-90-007	Electric	Vertically Integrated	1/31/1990	208.5	10.75	12.50	41.28	NA	12/5/1991	Settled	66.5	No	Yes	8.38	NA	NA	12/1990	NA	Year-end	23																															
Maryland	Delmarva Power & Light Co.	EXC	C-8389	Electric	Vertically Integrated	8/30/1991	9.2	10.31	13.15	42.86	NA	12/30/1991	Settled	5.5	No	No	NA	NA	NA	09/1991	NA	NA	4																															
Massachusetts	Western Massachusetts Electric	ES	DPU-91-290	Electric	Vertically Integrated	12/13/1991	37.4	10.47	13.5	37.43	NA	6/30/1992	Settled	23	Yes	No	NA	NA	NA	NA	NA	NA	6																															
Ohio	Columbus Southern Power Co.	AEP	C-91-1610-EL-AIR	Electric	Vertically Integrated	10/4/1991	7.7	10.31	13.00	44.80	NA	7/15/1992	Settled	3.3	No	No	9.93	NA	NA	12/1991	65.9	Date Certain	9																															
Maryland	Potomac Electric Power Co.	EXC	C-8466	Electric	Vertically Integrated	6/22/1992	86.4	10.39	13.25	45.98	NA	10/27/1992	Settled	29.3	Yes	No	NA	NA	NA	NA	NA	NA	4																															
South Dakota	Northern States Power Co. - MN	XEL	D-EL-92-016	Electric	Vertically Integrated	6/29/1992	6.3	10.16	12.5	49.9	NA	12/15/1992	Settled	4.2	Yes	No	NA	NA	NA	12/1991	NA	Average	5																															
Massachusetts	Eastern Edison Company		DPU-92-148	Electric	Vertically Integrated	6/15/1992	16.4	11.02	12.50	40.01	NA	12/30/1992	Settled	8.1	No	No	NA	NA	NA	12/1991	NA	Year-end	6																															
Maryland	Delmarva Power & Light Co.	EXC	C-8492	Electric	Vertically Integrated	10/30/1992	14.6	10.07	12.50	46.00	NA	3/26/1993	Settled	7.8	No	No	NA	NA	NA	NA	NA	NA	4																															
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-93-37	Electric	Vertically Integrated	7/31/1992	19.4	11.08	13.50	44.75	NA	8/18/1993	Settled	4.9	No	No	NA	NA	NA	05/1992	NA	Year-end	10																															
Ohio	Duke Energy Ohio Inc.	DUK	C-92-1464-EL-AIR	Electric	Vertically Integrated	9/16/1992	86.1	10.57	13.00	43.65	NA	8/26/1993	Settled	41.1	No	No	NA	NA	NA	05/1992	NA	Date Certain	11																															
Delaware	Delmarva Power & Light Co.	EXC	D-92-85	Electric	Vertically Integrated	10/30/1992	38.6	9.73	12	46	NA	10/5/1993	Settled	24.9	No	Yes	NA	NA	NA	12/1992	NA	Average	11																															
Maryland	Potomac Electric Power Co.	EXC	C-8565	Electric	Vertically Integrated	6/2/1993	49.9	9.89	12.75	44.79	NA	10/13/1993	Settled	27.0	No	No	NA	NA	NA	08/1993	NA	Average	4																															
Oklahoma	Public Service Co. of OK	AEP	Ca-PUD-920000-1342	Electric	Vertically Integrated	6/19/1992	41.6	9.98	11.85	51.17	NA	12/23/1993	Fully Litigated	14.4	No	No	NA	NA	NA	12/1992	NA	Average	18																															
Texas	Entergy Texas Inc.	ETR	D-12423	Electric	Vertically Integrated	9/29/1993	NA	NA	NA	NA	NA	12/29/1993	Settled	(42.5)	No	No	NA	NA	NA	12/1993	NA	Year-end	3																															
Arizona	Arizona Public Service Co.	PNW	D-U-1345-94-120	Electric	Vertically Integrated	4/20/1994	(38.3)	NA	NA	NA	NA	5/27/1994	Settled	(38.3)	No	No	NA	NA	NA	NA	NA	NA	1																															
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-94-163	Electric	Vertically Integrated	11/22/1993	5.1	10.46	12.33	55.20	NA	6/3/1994	Settled	2.2	No	No	NA	NA	NA	NA	NA	NA	6																															
Nevada	Nevada Power Co.	BRK-A	D-93-11045	Electric	Vertically Integrated	1/10/1994	29.1	9.70	12.50	NA	NA	7/14/1994	Settled	(6.3)	No	No	NA	NA	NA	NA	NA	NA	6																															
Missouri	Empire District Electric Co.	AQN	C-ER-94-174	Electric	Vertically Integrated	12/1/1993	8.0	10.23	12.50	49.44	NA	8/2/1994	Settled	7.4	No	No	NA	NA	NA	NA	NA	NA	6																															
New Mexico	Southwestern Public Service Co	XEL	C-2573	Electric	Vertically Integrated	2/25/1994	(4.0)	NA	NA	NA	NA	9/6/1994	Settled	(4.0)	No	No	NA	NA	NA	09/1992	NA	Year-end	6																															
Maryland	Potomac Edison Co.	FE	C-8652	Electric	Vertically Integrated	4/15/1994	30.9	9.46	12.25	42.85	NA	8/20/1994	Settled	19.0	No	No	NA	NA	NA	12/1993	NA	Average	5																															

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A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN	AO
Wisconsin	Wisconsin Power and Light Co	LNT	6680-UR-116 (elec)	Electric	Vertically Integrated	2/22/2008	93.3	10.08	10.80	55.40	1,356.90	12/30/2008	Settled	0.0	No	No	NA	NA	NA	12/2009	NA	NA	10																		
Wisconsin	Wisconsin Public Service Corp.	WEC	D-6690-UR-119 (elec)	Electric	Vertically Integrated	4/1/2008	68.4	9.29	10.90	58.11	1241.899	12/30/2008	Settled	48.0	No	No	NA	NA	NA	53.41	12/2009	NA	9																		
Kansas	Kansas Gas and Electric Co.	WR	D-08-WSEE-1041-RTS (KG&E)	Electric	Vertically Integrated	5/28/2008	87.6	8.69	10.95	48.46	1517.29187	12/1/2009	Settled	65.0	No	No	NA	NA	NA	NA	NA	NA	7																		
Kansas	Westar Energy Inc.	WR	D-08-WSEE-1041-RTS (WR)	Electric	Vertically Integrated	5/28/2008	90.0	8.68	10.95	48.46	1641.051081	12/1/2009	Settled	65.0	No	No	NA	NA	NA	NA	NA	NA	7																		
Kentucky	Kentucky Utilities Co.	PPL	C-2008-00251	Electric	Vertically Integrated	7/29/2008	22.2	7.77	11.25	52.63	2216.9	2/5/2009	Settled	(8.9)	No	No	NA	NA	NA	NA	NA	NA	6																		
Kentucky	Louisville Gas & Electric Co.	PPL	C-2008-00252 (elec.)	Electric	Vertically Integrated	7/29/2008	15.1	8.30	11.25	52.48	1,795.20	2/5/2009	Settled	(13.2)	No	No	NA	NA	NA	NA	NA	NA	6																		
Texas	Entergy Texas Inc.	ETR	D-34800	Electric	Vertically Integrated	9/26/2007	107.5	8.67	11.00	48.69	1,746.14	3/11/2009	Settled	30.5	No	Yes	NA	NA	NA	03/2007	NA	NA	17																		
Idaho	PacifiCorp	BRK-A	C-PAC-E-08-07	Electric	Vertically Integrated	9/19/2008	19.4	8.49	10.75	50.40	565.408155	4/16/2009	Settled	4.4	No	No	NA	NA	NA	NA	NA	NA	6																		
Wyoming	PacifiCorp	BRK-A	D-20000-333-ER-08	Electric	Vertically Integrated	7/24/2008	28.7	8.53	10.75	51.90	1,489.96	5/20/2009	Settled	19	No	No	NA	NA	NA	NA	NA	NA	10																		
Colorado	Public Service Co. of CO	XEL	D-08S-520E	Electric	Vertically Integrated	11/14/2008	159.3	9.01	11	58.08	4122.190289	5/27/2009	Settled	112.2	No	No	NA	NA	NA	NA	NA	NA	6																		
Texas	Southwestern Public Service Co	XEL	D-35763	Electric	Vertically Integrated	6/12/2008	94.4	8.85	11.25	51.01	989.40	6/2/2009	Settled	57.4	No	Yes	NA	NA	NA	12/2007	NA	NA	11																		
Missouri	Kansas City Power & Light	GXP	C-ER-2009-0089	Electric	Vertically Integrated	9/5/2008	101.5	8.69	10.75	53.82	1,501.35	6/10/2009	Settled	95.0	No	No	NA	NA	NA	12/2007	NA	Year-end	9																		
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-2009-0090 (L&P)	Electric	Vertically Integrated	9/5/2008	17.1	9.29	10.75	53.82	305.03	6/10/2009	Settled	15	No	No	NA	NA	NA	12/2007	NA	Year-end	9																		
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-2009-0090 (MPS)	Electric	Vertically Integrated	9/5/2008	66.0	8.93	10.75	53.82	1,202.23	6/10/2009	Settled	48.0	No	No	NA	NA	NA	12/2007	NA	Year-end	9																		
Kansas	Kansas City Power & Light	GXP	D-09-KCPE-246-RTS	Electric	Vertically Integrated	9/5/2008	71.6	8.75	10.75	55.39	1,254.15	6/24/2009	Settled	59.0	No	No	NA	NA	NA	12/2007	NA	Year-end	9																		
New Mexico	Southwestern Public Service Co	XEL	C-08-00354-UT	Electric	Vertically Integrated	12/18/2008	24.6	9.55	12.00	50.00	321	7/14/2009	Settled	14.2	No	Yes	NA	NA	NA	NA	NA	NA	6																		
Oklahoma	Oklahoma Gas and Electric Co.	OGE	Ca-PUD200800398	Electric	Vertically Integrated	2/27/2009	110.3	9.64	12.25	54.14	2862.736554	7/24/2009	Settled	48.3	No	No	NA	NA	NA	09/2008	NA	Year-end	4																		
Texas	Texas-New Mexico Power Co.	PNM	D-36025	Electric	Distribution	8/29/2008	24.4	10.16	11.25	40.00	430.10	8/21/2009	Settled	12.7	No	No	NA	NA	NA	03/2008	NA	NA	11																		
New Mexico	El Paso Electric Co.	EE	C-09-00171-UT	Electric	Vertically Integrated	5/29/2009	12.7	9.08	11.50	49.35	339.266	12/10/2009	Settled	5.5	No	No	NA	NA	NA	NA	339.266	Year-end	6																		
Washington	PacifiCorp	BRK-A	D-UE-090205	Electric	Vertically Integrated	2/6/2009	38.5	8.51	11	50.1	737.857615	12/16/2009	Settled	13.5	No	No	8.08	NA	NA	NA	NA	NA	10																		
South Dakota	Northern States Power Co. - MN	XEL	D-EL09-009	Electric	Vertically Integrated	6/30/2009	18.6	9.02	11.25	51.63	282.64	1/5/2010	Settled	10.9	No	No	8.32	NA	NA	NA	NA	NA	6																		
Texas	Southwestern Public Service Co	AEP	D-37364	Electric	Vertically Integrated	8/28/2009	91.9	8.78	11.50	50.65	668.735412	4/16/2010	Settled	25.0	No	No	NA	NA	NA	03/2009	NA	NA	7																		
Wyoming	PacifiCorp	BRK-A	D-20000-352-ER-09	Electric	Vertically Integrated	10/2/2009	62.0	8.63	11.00	52.80	1724.573806	5/14/2010	Settled	35.5	Yes	No	8.33	NA	NA	NA	1724.573806	NA	7																		
Kansas	Empire District Electric Co.	AQN	D-10-EPDE-314-RTS	Electric	Vertically Integrated	11/4/2009	5.2	8.80	11.30	48.29	69.181818	6/23/2010	Settled	2.8	No	No	NA	NA	NA	NA	NA	NA	7																		
West Virginia	Monongahela Power Co.	FE	C-09-1352-E-42T	Electric	Vertically Integrated	8/13/2009	122.1	9.31	12.25	41.80	1545.460907	6/25/2010	Settled	60.0	Yes	No	8.71	NA	NA	12/2008	1289.614248	NA	10																		
South Dakota	Black Hills Power Inc.	BKH	D-EL09-018	Electric	Vertically Integrated	9/29/2009	38.8	9.27	11.50	52.00	393.43	7/7/2010	Settled	22.0	No	Yes	8.26	NA	NA	06/2009	380.525518	Average	9																		
Kentucky	Kentucky Utilities Co.	PPL	C-2009-00548	Electric	Vertically Integrated	12/9/2010	135.3	8.32	11.50	53.85	3054.54362	7/30/2010	Settled	98.0	No	No	NA	NA	NA	10/2009	NA	Year-end	6																		
Kentucky	Louisville Gas & Electric Co.	PPL	C-2009-00549 (elec.)	Electric	Vertically Integrated	12/9/2010	94.6	8.32	11.5	53.86	1805.791767	7/30/2010	Settled	74.0	No	No	NA	NA	NA	10/2009	NA	Year-end	6																		
Texas	El Paso Electric Co.	EE	D-37690	Electric	Vertically Integrated	12/9/2009	50.8	9.22	11.35	51.27	969.24	7/30/2010	Settled	17.2	No	Yes	NA	NA	NA	09/2009	NA	NA	7																		
Missouri	Empire District Electric Co.	AQN	C-ER-2010-0130	Electric	Vertically Integrated	10/29/2009	68.2	8.93	11.00	48.00	1,077.38	8/18/2010	Settled	46.8	No	No	NA	NA	NA	06/2009	NA	Year-end	9																		
Idaho	Avista Corp.	AVA	C-AVU-E-10-01	Electric	Vertically Integrated	3/23/2010	32.1	8.55	10.90	50	607.962	9/21/2010	Settled	21.3	No	No	NA	NA	NA	12/2009	NA	NA	6																		
Pennsylvania	PECO Energy Co.	EXC	D-R-2010-2161575	Electric	Distribution	3/31/2010	316.4	8.95	11.75	53.18	3238	12/16/2010	Settled	225.0	No	No	NA	NA	NA	12/2010	NA	NA	8																		
Pennsylvania	PPL Electric Utilities Corp.	PPL	D-R-2010-2161694	Electric	Distribution	3/31/2010	114.7	9.11	11.75	48.37	2244.957	12/16/2010	Settled	77.5	No	No	NA	NA	NA	12/2010	NA	NA	8																		
Pennsylvania	Duquesne Light Co.		D-R-2010-2179522	Electric	Distribution	7/23/2010	87.3	8.78	11.25	52.42	1439.932	2/24/2011	Settled	45.7	No	No	NA	NA	NA	03/2011	NA	NA	7																		
Texas	Southwestern Public Service Co	XEL	D-38147	Electric	Vertically Integrated	5/17/2010	55.4	9.24	11.35	51	941.080248	3/25/2011	Settled	52.5	Yes	Yes	NA	NA	NA	12/2009	NA	NA	10																		
California	Pacific Gas and Electric Co.	PCG	AP-09-12-020 (elec)	Electric	Vertically Integrated	12/21/2009	856.0	NA	NA	NA	14783	5/13/2011	Settled	403.0	Yes	No	NA	NA	NA	12/2011	14,174.95	Average	16																		
Missouri	Empire District Electric Co.	AQN	C-ER-2011-0004	Electric	Vertically Integrated	9/28/2010	36.5	8.82	10.60	50.95	1067.90799	6/1/2011	Settled	18.7	No	No	NA	NA	NA	09/2009	NA	NA	8																		
Maryland	Delmarva Power & Light Co.	EXC	C-9249	Electric	Distribution	12/21/2010	18.3	8.08	10.75	49.81	344.568	7/8/2011	Settled	12.2	No	No	NA	NA	NA	12/2010	NA	NA	6																		
Montana	MDU Resources Group Inc.	MDU	D-D2010.8.82	Electric	Vertically Integrated	8/11/2010	4.9	8.78	11.00	51.15	87.251386	8/2/2011	Settled	2.8	No	Yes	NA	NA	NA	NA	NA	NA	11																		
Idaho	Avista Corp.	AVA	C-AVU-E-11-01	Electric	Vertically Integrated	7/5/2011	9.0	8.49	10.90	50.15	627.001	9/30/2011	Settled	2.8	No	No	NA	NA	NA	12/2010	NA	NA	2																		
Wisconsin	Wisconsin Electric Power Co.	WEC	D-5-UR-105 (WEP-EL)	Electric	Vertically Integrated	5/26/2011	0.0	NA	NA	NA	NA	10/6/2011	Fully Litigated	0.0	No	No	NA	NA	NA	12/2012	NA	NA	4																		
Washington	Avista Corp.	AVA	D-UE-110876	Electric	Vertically Integrated	5/16/2011	38.3	8.23	10.90	48.04	1127.811	12/16/2011	Settled	20.0	No	No	NA	NA	NA	NA	NA	NA	7																		
Texas	Southwestern Electric Power Co	AEP	D-39708	Electric	Vertically Integrated	8/31/2011	60.3	8.21	10.33	49.70	372.903412	12/21/2011	Fully Litigated	NA	No	No	NA	NA	NA	NA	NA	NA	3																		
New Mexico	Southwestern Public Service Co	XEL	C-10-00395-UT	Electric	Vertically Integrated	2/28/2011	19.9	9.04	11.25	51.11	390.276527	12/28/2011	Settled	13.5	No	No	NA	NA	NA	NA	NA	NA	10																		
Idaho	Idaho Power Co.	IDA	C-IPC-E-11-08	Electric	Vertically Integrated	6/1/2011	82.6	8.17	10.50	51.20	2,355.91	12/30/2011	Settled	34.0	No	No	7.86	NA	NA	12/2011	2,355.91	NA	7																		
Illinois	Ameren Illinois	AEE	D-11-0279 (elec)	Electric	Distribution	2/18/2011	39.0	9.44	11.00	52.87	2,012.81	1/5/2012	Fully Litigated	NA	No	No	NA	NA	NA	NA	NA	NA	10																		
Idaho	PacifiCorp	BRK-A	C-PAC-E-11-12	Electric	Vertically Integrated	5/27/2011	32.7	8.25	10.50	52.30	745.70	1/10/2012	Settled	34.0	Yes	No	NA	NA	NA	12/2010	NA	NA	7																		
Florida	Duke Energy Florida LLC	DUK	D-120022-EI	Electric	Vertically Integrated	1/20/2012	150.0	NA	NA	NA	NA	2/22/2012	Settled	150.0	No	No	NA	NA	NA	NA	NA	NA	1																		
Washington	PacifiCorp	BRK-A	D-UE-111190	Electric	Vertically Integrated	7/1/2011	12.9	7.74	NA	NA	750.49584	3/30/2012	Settled	4.5	No	No	7.74	NA	NA	12/2010	NA	NA	9																		
Kansas	Westar Energy Inc.	WR	D-12-WSEE-112-RTS	Electric	Vertically Integrated	8/25/2011	90.8	8.88	10.60	51.62	3,399.27	4/18/2012	Settled	50.0	No	No	NA	NA	NA	03/2011	NA	NA	7																		
Texas	El Paso Electric Co.	EE	D-40094	Electric	Vertically Integrated	2/1/2012	26.3	8.94	10.60	53.38	1,126.22	5/18/2012	Settled	(15.0)	No	Yes	NA	NA	NA	09/2011	NA	NA	3																		
California	Southern California Edison Co.	EIX	AP-10-11-015	Electric	Vertically Integrated	11/23/2010	809.0	NA	NA	NA	16,224.21	11/29/2012	Fully Litigated	271.9	Yes	No	NA	NA	NA	12/2012	15072.221	Average	24																		
Missouri	Empire District Electric Co.	AQN	C-ER-2012-0345	Electric	Vertically Integrated	7/6/2012	30.7	8.32	10.60	51.00	1005.673388	2/27/2013	Settled	27.5	No	No	NA	NA	NA	03/2012	NA	NA	7																		
Hawaii	Hawaii Electric Light Co	HE	D-2012-0099	Electric	Vertically Integrated	8/16/2012	19.8	8.30	10.25	57.05	455	3/19/2013	Settled	NA	No	No	NA	NA	NA	NA	NA	NA	7																		
South Dakota	Northern States Power Co. - MN	XEL	D-EL12-046	Electric	Vertically Integrated	6/29/2012	19.4	8.51	10.65	52.89	367.51	4/18/2013	Settled	11.6	No	Yes	7.78	NA	NA	12/2011	351.738	Average	9																		
California	San Diego Gas & Electric Co.	SRE	AP-10-12-005 (elec)	Electric	Vertically Integrated	12/15/2010	201.8	NA	NA	NA	3,743.25	5/9/2013	Fully Litigated	115.184	Yes	No	NA	NA	NA	12/2012	3574.122	Average	29																		
Texas	Southwestern Public Service Co	XEL	D-40824	Electric	Vertically Integrated	11/15/2012	90.2	8.62	10.65	52.00	1150.577572	6/6/2013	Settled	50.8	Yes	Yes	NA	NA	NA	06/2012	NA	NA	6																		
Wisconsin	Madison Gas and Electric Co.	MGEE	D-3270-UR-119 (Elec)	Electric	Vertically Integrated	4/15/2013	0.0	NA	NA	NA	NA	7/26/2013	Settled	0.0	No	No	NA	NA	NA	12/2014	NA	NA	3																		
Maryland	Delmarva Power & Light Co.	EXC	C-9317	Electric	Distribution	3/29/2013	22.6	7.67	10.25	49.58	507.858	9/3/2013	Settled	15.0	No	No	NA	NA	NA	12/2012	NA	NA	5																		
South Dakota	Black Hills Power Inc.	BKH	D-EL12-061	Electric	Vertically Integrated	12/17/2012	13.7	8.54	10.25	53.17	438.29	9/17/2013	Settled	8.8	No	Yes	7.93	NA	NA	NA	NA	NA	9																		
Idaho	PacifiCorp	BRK-A	C-PAC-E-13-04	Electric	Vertically Integrated	6/3/2013	2.0	NA	NA	NA	NA	10/24/2013	Settled	2.0	No	No	NA	NA	NA	NA	NA	NA	4																		
Kentucky	Kentucky Power Co.	AEP	C-2013-00197	Electric	Vertically Integrated	6/28/2013	114.0	8.08	10.65	45.80	1,584.18	11/22/2013	Fully Litigated	NA	No	No	NA	NA	NA	NA	NA	NA	4																		
Virginia	Kentucky Utilities Co.	PPL	PUE-2013-00013	Electric	Vertically Integrated	4/1/2013	6.5	7.59	10.8	54.52	192.996131	11/25/2013	Settled	4.7	No	No	NA	NA	NA	12/2012	NA	NA	7																		
Iowa	MidAmerican Energy Co.	BRK-A	D-RPU-2013-0004	Electric	Vertically Integrated	5/17/2013	266.2	7.80	11.01	51.54	5,893.41	2/28/2014	Settled	263.553	Yes	Yes	NA	NA	NA	12/2012	NA	NA	9																		
Pennsylvania	Duquesne Light Co.		D-R-2013-2372129	Electric	Distribution	8/2/2013	76.3	8.38	11.25	51.94	1,543.25	4/23/2014	Settled	48.0	No	No	NA	NA	NA	04/2015	NA	NA	8																		
Kansas	Kansas City Power & Light	GXP	D-14-KCPE-272-RTS	Electric	Vertically Integrated	12/9/2013	11.5	NA	NA	NA	1,916.14	7/17/2014	Settled	11.5	No	No	NA	NA	NA	12/2011	1916.139859	Year-end	7																		
California	Pacific Gas and Electric Co.	PCG	AP-12-11-009 (Elec)	Electric	Vertically Integrated	11/15/2012	713.0	NA	NA	NA	17299.245	8/14/2014	Fully Litigated	196.0	Yes	No	NA	NA	NA	12/2014	16822.526	Average	21																		
Idaho	Avista Corp.	AVA	C-AVU-E-14-05	Electric	Vertically Integrated	5/30/2014	NA	NA	NA	NA	NA	9/18/2014	Settled	0.0	No	No	NA	NA	NA	NA	NA	NA	3																		
Washington	Avista Corp.	AVA	D-UE-140188	Electric	Vertically Integrated	2/4/2014	18.2	7.71	10.10	49.00	1365.444	11/25/2014	Settled	7.0	No	No	NA	NA	NA	06/2013	NA	NA	9																		
Maryland	Baltimore Gas and Electric Co.	EXC	C-9355 (elec)	Electric	Distribution	7/2/2014	98.7	7.93	10.65	52.30	2914	12/12/2014	Settled	22.0	No	No	NA	NA	NA	08/2014	NA	NA	5																		
Texas	Southwestern Public Service Co	XEL	D-42004	Electric	Vertically Integrated	1/7/2014	76.9	8.43	10.40	53.89	1,273.28	12/18/2014	Settled	37	No	Yes	NA	NA	NA	06/2013	NA	NA	11																		
West Virginia	Monongahela Power Co.	FE	C-14-0702-E-42T	Electric	Vertically Integrated	4/30/2014	212.6	7.87	11.00	46.47	2,511.88	2/4/2015	Settled	124.3	No	No	NA	NA	NA	12/2013	NA	NA	9																		
South Dakota	Black Hills Power Inc.	BKH	D-EL14-026	Electric	Vertically Integrated	3/31/2014	14.6	8.48	10.25	53.32	542.70	3/2/2015	Settled	6.9	No	Yes	7.76	NA	NA	09/2013	543.925179	Average	11																		
Pennsylvania	Metropolitan Edison Co.	FE	D-R-2014-2428745	Electric	Distribution	8/4/2014	168.3	8.05	10.90	49.98	1,413.00	4/8/2015	Settled	105.7	No	No	NA	NA	NA	04/2016	NA	NA	8																		
Pennsylvania	Pennsylvania Electric Co.	FE	D-R-2014-2428743	Electric	Distribution	8/4/2014	136.8	8.31	10.90	49.90	1,540.30	4/8/2015	Settled	107.8	No	No	NA	NA	NA	04/2016	NA	NA	8																		
Pennsylvania	Pennsylvania Power Co.	FE	D-R-2014-2428744	Electric	Distribution	8/4/2014	38.0	8.51	10.90	50.07	358.93	4/8/2015	Settled	25.5	No	No	NA	NA	NA	04/2016	NA	NA	8																		
Pennsylvania	West Penn Power Co.	FE	D-R-2014-2428742	Electric	Distribution	8/4/2014	114.0	8.14	10.90	50.13	1,287.29	4/8/2015	Settled	95.2	No	No	NA	NA	NA	04/2016	NA	NA	8																		
Oklahoma	Public Service Co. of OK	AEP	Ca-PUD201300217	Electric	Vertically Integrated	1/17/2014	37.7	7.94	10.50	48.69	1,860.91	4/14/2015	Settled	(4.8)	No	Yes	7.83	NA	NA	07/2013	1908.675876	Year-end	15																		
New Mexico	Public Service Co. of NM	PNM	C-14-00332-UT	Electric	Vertically Integrated	12/11/2014	107.4	8.29	10.50	49.60	2387.760427	5/13/2015	Fully Litigated	NA	No	No	NA	NA	NA	NA	NA	NA	5																		
South Dakota	Northern States Power Co. - MN	XEL	D-EL14-058	Electric	Vertically Integrated	6/23/2014	24.6	7.94	10.25	53.88	433.242	6/15/2015	Settled	15.2	No	Yes	7.22	NA	NA	12/2013	412.436	Average	11																		
Kentucky	Kentucky Power Co.	AEP	C-2014-00366	Electric	Vertically Integrated	12/23/2014	(4.7)	7.71	10.82	45.18	1147.480328	8/22/2015	Settled	(23.0)	No	No	NA	NA	NA	09/2014	NA	NA	6																		
Missouri	Empire District Electric Co.	AQN	C-ER-2014-0351	Electric	Vertically Integrated	8/29/2014	24.3	7.94	10.15	51.45	1164.924075	8/24/2015	Settled	17.1	No	No	NA	NA	NA	04/2014	NA	NA	9																		
New Mexico	Southwestern Public Service Co	XEL	C-15-00139-UT	Electric	Vertically Integrated	6/8/2015	31.5	8.10	10.25	53.97	777.855379	6/24/2015	Fully Litigated	NA	No	No	NA	NA	NA	NA	NA	NA	0																		
Kentucky	Kentucky Utilities Co.	PPL	C-2014-00371	Electric	Vertically Integrated	11/26/2014	153.4	7.38	10.50	53.02	3568.968428	6/30/2015	Settled	125.0	No	No	NA	NA	NA	08/2016	NA	NA	7																		
Kentucky	Louisville Gas & Electric Co.	PPL	C-2014-00372 (elec.)	Electric	Vertically Integrated	11/26/2014	30.3	7.36	10.50	52.75	2146.046494	6/30/2015	Settled	0.0	No	No	NA	NA	NA	08/2016	NA	NA	7																		
Texas	Entergy Texas Inc.	ETR	D-44704	Electric	Vertically Integrated	6/12/2015	75.9	8.36	10.20	50.08	2,004.59	7/20/2015	Fully Litigated	NA	No	No	NA	NA	NA	NA	NA	NA	1																		
Kansas	Westar Energy Inc.	WR	D-15-WSEE-115-RTS	Electric	Vertically Integrated	3/2/2015	250.9	7.99	10.00	53.12	5,062.80	9/24/2015	Settled	185.3	No	No	NA	NA	NA	09/2014	NA	NA	6																		
South Dakota	NorthWestern Corp.	NWE	D-EL14-106	Electric	Vertically Integrated	12/19/2014	26.5	7.76	10	53.61	447.40	10/29/2015	Settled	40.7	Yes	Yes	7.24	NA	NA	NA	NA	NA	10																		
California	Southern California Edison Co.	EIX	A-13-11-003	Electric	Vertically Integrated	11/12/2013	(120.9)	NA	NA	NA	18,175.82	11/5/2015	Fully Litigated	(450.4)	Yes	No	NA	NA	NA	12/2015	17375.834	Average	24																		
Pennsylvania	PPL Electric Utilities Corp.	PPL	D-R-2015-2469275	Electric	Distribution	3/31/2015	167.5	8.15	10.95	51.66	3,156.00	11/19/2015	Settled	124.0	No	No	NA	NA	NA	12/2016	NA	NA	7																		
Virginia	Virginia Electric & Power Co.	D	C-PUE-2015-00027	Electric	Vertically Integrated	3/31/2015	0.0	NA	NA	NA	8,921.00	11/23/2015	Fully Litigated	0.0	No	No	NA	NA	NA	12/2014	NA	NA	7																		
Tennessee	Kingsport Power Company	AEP	D-15-00093	Electric	Vertically Integrated	9/28/2015	12.1	6.69	10.66	42.43	71.50	12/15/2015	NA	NA	No	No	NA	NA	NA	NA	NA	NA	2																		

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USGG30YR Index

Date	PX_LAST	Yield (%)	Average Price Based on Lag	Date	
5/18/2018	3.1974	3.20%	2.93%	1/2/1979	8.99%
5/17/2018	3.2462	3.25%	2.92%	1/3/1979	8.98%
5/16/2018	3.2172	3.22%	2.92%	1/4/1979	8.96%
5/15/2018	3.2007	3.20%	2.92%	1/5/1979	8.96%
5/14/2018	3.1347	3.13%	2.92%	1/8/1979	8.96%
5/11/2018	3.1041	3.10%	2.92%	1/9/1979	8.97%
5/10/2018	3.1082	3.11%	2.92%	1/10/1979	8.97%
5/9/2018	3.1618	3.16%	2.91%	1/11/1979	8.97%
5/8/2018	3.1295	3.13%	2.91%	1/12/1979	8.97%
5/7/2018	3.1229	3.12%	2.91%	1/15/1979	8.97%
5/4/2018	3.1221	3.12%	2.91%	1/16/1979	8.97%
5/3/2018	3.1213	3.12%	2.91%	1/17/1979	8.97%
5/2/2018	3.146	3.15%	2.91%	1/18/1979	8.98%
5/1/2018	3.1287	3.13%	2.91%	1/19/1979	8.98%
4/30/2018	3.1237	3.12%	2.91%	1/22/1979	8.97%
4/27/2018	3.1245	3.12%	2.90%	1/23/1979	8.97%
4/26/2018	3.1642	3.16%	2.90%	1/24/1979	8.97%
4/25/2018	3.2068	3.21%	2.90%	1/25/1979	8.96%
4/24/2018	3.1825	3.18%	2.90%	1/26/1979	8.95%
4/23/2018	3.1443	3.14%	2.90%	1/29/1979	8.95%
4/20/2018	3.1451	3.15%	2.90%	1/30/1979	8.94%
4/19/2018	3.0983	3.10%	2.89%	1/31/1979	8.94%
4/18/2018	3.0601	3.06%	2.89%	2/1/1979	8.93%
4/17/2018	3.0198	3.02%	2.89%	2/2/1979	8.93%
4/16/2018	3.0246	3.02%	2.89%	2/5/1979	8.93%
4/13/2018	3.027	3.03%	2.89%	2/6/1979	8.93%
4/12/2018	3.0431	3.04%	2.89%	2/7/1979	8.93%
4/11/2018	2.9951	3.00%	2.89%	2/8/1979	8.93%
4/10/2018	3.0214	3.02%	2.89%	2/9/1979	8.94%
4/9/2018	3.0118	3.01%	2.89%	2/13/1979	8.94%
4/6/2018	3.0182	3.02%	2.89%	2/14/1979	8.94%
4/5/2018	3.073	3.07%	2.89%	2/15/1979	8.94%
4/4/2018	3.0359	3.04%	2.89%	2/16/1979	8.94%
4/3/2018	3.011	3.01%	2.89%	2/20/1979	8.95%
4/2/2018	2.9619	2.96%	2.88%	2/21/1979	8.95%
3/30/2018	2.9737	2.97%	2.88%	2/22/1979	8.95%
3/29/2018	2.9737	2.97%	2.88%	2/23/1979	8.96%
3/28/2018	3.0214	3.02%	2.88%	2/26/1979	8.96%
3/27/2018	3.0286	3.03%	2.88%	2/27/1979	8.96%
3/26/2018	3.0859	3.09%	2.88%	2/28/1979	8.97%
3/23/2018	3.0608	3.06%	2.88%	3/1/1979	8.97%
3/22/2018	3.0624	3.06%	2.87%	3/2/1979	8.97%

3/21/2018	3.1186	3.12%	2.87%	3/5/1979	8.97%
3/20/2018	3.1301	3.13%	2.87%	3/6/1979	8.98%
3/19/2018	3.0859	3.09%	2.87%	3/7/1979	8.98%
3/16/2018	3.077	3.08%	2.87%	3/8/1979	8.98%
3/15/2018	3.0584	3.06%	2.87%	3/9/1979	8.98%
3/14/2018	3.0568	3.06%	2.87%	3/12/1979	8.98%
3/13/2018	3.0981	3.10%	2.87%	3/13/1979	8.98%
3/12/2018	3.1292	3.13%	2.86%	3/14/1979	8.98%
3/9/2018	3.158	3.16%	2.86%	3/15/1979	8.98%
3/8/2018	3.1218	3.12%	2.86%	3/16/1979	8.98%
3/7/2018	3.1498	3.15%	2.86%	3/19/1979	8.98%
3/6/2018	3.1531	3.15%	2.86%	3/20/1979	8.99%
3/5/2018	3.1531	3.15%	2.86%	3/21/1979	8.99%
3/2/2018	3.1398	3.14%	2.86%	3/22/1979	8.99%
3/1/2018	3.0834	3.08%	2.85%	3/23/1979	8.99%
2/28/2018	3.1242	3.12%	2.85%	3/26/1979	8.99%
2/27/2018	3.1588	3.16%	2.85%	3/27/1979	8.99%
2/26/2018	3.153	3.15%	2.85%	3/28/1979	8.99%
2/23/2018	3.1555	3.16%	2.85%	3/29/1979	8.99%
2/22/2018	3.2062	3.21%	2.85%	3/30/1979	8.99%
2/21/2018	3.2204	3.22%	2.85%	4/2/1979	8.99%
2/20/2018	3.153	3.15%	2.85%	4/3/1979	8.99%
2/19/2018	3.1316	3.13%	2.85%	4/4/1979	8.99%
2/16/2018	3.1316	3.13%	2.84%	4/5/1979	8.99%
2/15/2018	3.1637	3.16%	2.84%	4/6/1979	8.99%
2/14/2018	3.162	3.16%	2.84%	4/9/1979	8.99%
2/13/2018	3.1111	3.11%	2.84%	4/10/1979	8.99%
2/12/2018	3.1439	3.14%	2.84%	4/11/1979	8.99%
2/9/2018	3.1596	3.16%	2.84%	4/12/1979	8.99%
2/8/2018	3.1293	3.13%	2.84%	4/16/1979	9.00%
2/7/2018	3.1139	3.11%	2.84%	4/17/1979	9.00%
2/6/2018	3.0659	3.07%	2.84%	4/18/1979	9.00%
2/5/2018	3.006	3.01%	2.84%	4/19/1979	9.00%
2/2/2018	3.0868	3.09%	2.84%	4/20/1979	9.00%
2/1/2018	3.0241	3.02%	2.84%	4/23/1979	9.00%
1/31/2018	2.9348	2.93%	2.84%	4/24/1979	9.00%
1/30/2018	2.9706	2.97%	2.84%	4/25/1979	9.01%
1/29/2018	2.9421	2.94%	2.84%	4/26/1979	9.01%
1/26/2018	2.9114	2.91%	2.84%	4/27/1979	9.01%
1/25/2018	2.8809	2.88%	2.84%	4/30/1979	9.01%
1/24/2018	2.9283	2.93%	2.84%	5/1/1979	9.01%
1/23/2018	2.8945	2.89%	2.84%	5/2/1979	9.02%
1/22/2018	2.913	2.91%	2.84%	5/3/1979	9.02%
1/19/2018	2.9331	2.93%	2.84%	5/4/1979	9.02%
1/18/2018	2.9033	2.90%	2.84%	5/7/1979	9.03%
1/17/2018	2.857	2.86%	2.84%	5/8/1979	9.03%
1/16/2018	2.8254	2.83%	2.84%	5/9/1979	9.03%

1/15/2018	2.8491	2.85%	2.84%	5/10/1979	9.03%
1/12/2018	2.8491	2.85%	2.84%	5/11/1979	9.04%
1/11/2018	2.8673	2.87%	2.84%	5/14/1979	9.04%
1/10/2018	2.8984	2.90%	2.84%	5/15/1979	9.04%
1/9/2018	2.8952	2.90%	2.84%	5/16/1979	9.04%
1/8/2018	2.8113	2.81%	2.84%	5/17/1979	9.04%
1/5/2018	2.8105	2.81%	2.84%	5/18/1979	9.05%
1/4/2018	2.7863	2.79%	2.84%	5/21/1979	9.05%
1/3/2018	2.7855	2.79%	2.84%	5/22/1979	9.05%
1/2/2018	2.8136	2.81%	2.84%	5/23/1979	9.05%
1/1/2018	2.7399	2.74%	2.85%	5/24/1979	9.05%
12/29/2017	2.7399	2.74%	2.85%	5/25/1979	9.05%
12/28/2017	2.7561	2.76%	2.85%	5/29/1979	9.05%
12/27/2017	2.7461	2.75%	2.85%	5/31/1979	9.05%
12/26/2017	2.8246	2.82%	2.85%	6/1/1979	9.05%
12/25/2017	2.8309	2.83%	2.85%	6/4/1979	9.05%
12/22/2017	2.8309	2.83%	2.85%	6/5/1979	9.05%
12/21/2017	2.8419	2.84%	2.85%	6/6/1979	9.05%
12/20/2017	2.8767	2.88%	2.86%	6/7/1979	9.05%
12/19/2017	2.8198	2.82%	2.86%	6/8/1979	9.05%
12/18/2017	2.7407	2.74%	2.86%	6/11/1979	9.05%
12/15/2017	2.6873	2.69%	2.86%	6/12/1979	9.04%
12/14/2017	2.7063	2.71%	2.86%	6/13/1979	9.04%
12/13/2017	2.7269	2.73%	2.87%	6/14/1979	9.04%
12/12/2017	2.7762	2.78%	2.87%	6/15/1979	9.04%
12/11/2017	2.7762	2.78%	2.87%	6/18/1979	9.04%
12/8/2017	2.7685	2.77%	2.87%	6/19/1979	9.04%
12/7/2017	2.7607	2.76%	2.87%	6/20/1979	9.04%
12/6/2017	2.73	2.73%	2.87%	6/21/1979	9.04%
12/5/2017	2.7315	2.73%	2.88%	6/22/1979	9.04%
12/4/2017	2.7638	2.76%	2.88%	6/25/1979	9.03%
12/1/2017	2.7615	2.76%	2.88%	6/26/1979	9.03%
11/30/2017	2.8269	2.83%	2.88%	6/27/1979	9.03%
11/29/2017	2.8245	2.82%	2.88%	6/28/1979	9.03%
11/28/2017	2.7577	2.76%	2.88%	6/29/1979	9.03%
11/27/2017	2.7677	2.77%	2.88%	7/2/1979	9.03%
11/24/2017	2.7638	2.76%	2.88%	7/3/1979	9.02%
11/23/2017	2.7392	2.74%	2.89%	7/5/1979	9.02%
11/22/2017	2.7392	2.74%	2.89%	7/6/1979	9.02%
11/21/2017	2.7577	2.76%	2.89%	7/9/1979	9.02%
11/20/2017	2.7801	2.78%	2.89%	7/10/1979	9.02%
11/17/2017	2.7778	2.78%	2.89%	7/11/1979	9.02%
11/16/2017	2.8268	2.83%	2.89%	7/12/1979	9.02%
11/15/2017	2.7646	2.76%	2.89%	7/13/1979	9.02%
11/14/2017	2.83	2.83%	2.89%	7/16/1979	9.02%
11/13/2017	2.871	2.87%	2.90%	7/17/1979	9.02%
11/10/2017	2.8797	2.88%	2.90%	7/18/1979	9.02%

11/9/2017	2.8161	2.82%	2.90%	7/19/1979	9.02%
11/8/2017	2.7918	2.79%	2.90%	7/20/1979	9.02%
11/7/2017	2.777	2.78%	2.90%	7/23/1979	9.01%
11/6/2017	2.7941	2.79%	2.90%	7/24/1979	9.01%
11/3/2017	2.8129	2.81%	2.90%	7/25/1979	9.01%
11/2/2017	2.8255	2.83%	2.90%	7/26/1979	9.01%
11/1/2017	2.8579	2.86%	2.91%	7/27/1979	9.01%
10/31/2017	2.8794	2.88%	2.91%	7/30/1979	9.01%
10/30/2017	2.8802	2.88%	2.91%	7/31/1979	9.01%
10/27/2017	2.9179	2.92%	2.91%	8/1/1979	9.01%
10/26/2017	2.9714	2.97%	2.91%	8/2/1979	9.01%
10/25/2017	2.9404	2.94%	2.91%	8/3/1979	9.01%
10/24/2017	2.9331	2.93%	2.91%	8/6/1979	9.01%
10/23/2017	2.8833	2.88%	2.91%	8/7/1979	9.01%
10/20/2017	2.8969	2.90%	2.91%	8/8/1979	9.01%
10/19/2017	2.8365	2.84%	2.91%	8/9/1979	9.01%
10/18/2017	2.8562	2.86%	2.91%	8/10/1979	9.01%
10/17/2017	2.8019	2.80%	2.91%	8/13/1979	9.01%
10/16/2017	2.8231	2.82%	2.91%	8/14/1979	9.01%
10/13/2017	2.805	2.81%	2.91%	8/15/1979	9.01%
10/12/2017	2.8467	2.85%	2.91%	8/16/1979	9.01%
10/11/2017	2.8824	2.88%	2.91%	8/17/1979	9.01%
10/10/2017	2.8952	2.90%	2.92%	8/20/1979	9.01%
10/9/2017	2.8936	2.89%	2.92%	8/21/1979	9.01%
10/6/2017	2.8936	2.89%	2.92%	8/22/1979	9.01%
10/5/2017	2.8904	2.89%	2.92%	8/23/1979	9.01%
10/4/2017	2.8657	2.87%	2.92%	8/24/1979	9.01%
10/3/2017	2.8641	2.86%	2.92%	8/27/1979	9.01%
10/2/2017	2.8736	2.87%	2.92%	8/28/1979	9.01%
9/29/2017	2.8601	2.86%	2.92%	8/29/1979	9.01%
9/28/2017	2.8712	2.87%	2.92%	8/30/1979	9.01%
9/27/2017	2.8625	2.86%	2.93%	8/31/1979	9.01%
9/26/2017	2.7739	2.77%	2.93%	9/4/1979	9.01%
9/25/2017	2.7615	2.76%	2.93%	9/5/1979	9.01%
9/22/2017	2.7801	2.78%	2.93%	9/6/1979	9.01%
9/21/2017	2.805	2.81%	2.93%	9/7/1979	9.01%
9/20/2017	2.8081	2.81%	2.93%	9/10/1979	9.01%
9/19/2017	2.8167	2.82%	2.94%	9/11/1979	9.01%
9/18/2017	2.7987	2.80%	2.94%	9/12/1979	9.02%
9/15/2017	2.77	2.77%	2.94%	9/13/1979	9.02%
9/14/2017	2.7669	2.77%	2.94%	9/14/1979	9.02%
9/13/2017	2.7863	2.79%	2.94%	9/17/1979	9.02%
9/12/2017	2.7715	2.77%	2.94%	9/18/1979	9.02%
9/11/2017	2.743	2.74%	2.95%	9/19/1979	9.02%
9/8/2017	2.6692	2.67%	2.95%	9/20/1979	9.02%
9/7/2017	2.6572	2.66%	2.95%	9/21/1979	9.02%
9/6/2017	2.7224	2.72%	2.95%	9/24/1979	9.02%

9/5/2017	2.6806	2.68%	2.95%	9/25/1979	9.02%
9/4/2017	2.777	2.78%	2.95%	9/26/1979	9.02%
9/1/2017	2.777	2.78%	2.96%	9/27/1979	9.02%
8/31/2017	2.7262	2.73%	2.96%	9/28/1979	9.03%
8/30/2017	2.7377	2.74%	2.96%	10/1/1979	9.03%
8/29/2017	2.7384	2.74%	2.96%	10/2/1979	9.03%
8/28/2017	2.7554	2.76%	2.96%	10/3/1979	9.03%
8/25/2017	2.7469	2.75%	2.96%	10/4/1979	9.03%
8/24/2017	2.7692	2.77%	2.96%	10/5/1979	9.03%
8/23/2017	2.7461	2.75%	2.96%	10/9/1979	9.04%
8/22/2017	2.7847	2.78%	2.97%	10/10/1979	9.04%
8/21/2017	2.7631	2.76%	2.97%	10/11/1979	9.04%
8/18/2017	2.7762	2.78%	2.97%	10/12/1979	9.05%
8/17/2017	2.7739	2.77%	2.97%	10/15/1979	9.05%
8/16/2017	2.8073	2.81%	2.97%	10/16/1979	9.05%
8/15/2017	2.8488	2.85%	2.97%	10/17/1979	9.06%
8/14/2017	2.8073	2.81%	2.97%	10/18/1979	9.06%
8/11/2017	2.7855	2.79%	2.97%	10/19/1979	9.07%
8/10/2017	2.7729	2.77%	2.97%	10/22/1979	9.07%
8/9/2017	2.8222	2.82%	2.96%	10/23/1979	9.08%
8/8/2017	2.8428	2.84%	2.96%	10/24/1979	9.09%
8/7/2017	2.8336	2.83%	2.96%	10/25/1979	9.09%
8/4/2017	2.842	2.84%	2.96%	10/26/1979	9.10%
8/3/2017	2.7972	2.80%	2.96%	10/29/1979	9.11%
8/2/2017	2.8559	2.86%	2.96%	10/30/1979	9.11%
8/1/2017	2.8567	2.86%	2.96%	10/31/1979	9.12%
7/31/2017	2.8999	2.90%	2.96%	11/1/1979	9.12%
7/28/2017	2.8953	2.90%	2.95%	11/2/1979	9.13%
7/27/2017	2.9194	2.92%	2.95%	11/5/1979	9.14%
7/26/2017	2.8914	2.89%	2.95%	11/7/1979	9.15%
7/25/2017	2.9171	2.92%	2.95%	11/8/1979	9.15%
7/24/2017	2.8345	2.83%	2.95%	11/9/1979	9.16%
7/21/2017	2.8087	2.81%	2.94%	11/13/1979	9.17%
7/20/2017	2.8254	2.83%	2.94%	11/14/1979	9.18%
7/19/2017	2.8514	2.85%	2.94%	11/15/1979	9.18%
7/18/2017	2.8461	2.85%	2.94%	11/16/1979	9.19%
7/17/2017	2.9039	2.90%	2.94%	11/19/1979	9.20%
7/14/2017	2.9195	2.92%	2.94%	11/20/1979	9.21%
7/13/2017	2.9172	2.92%	2.93%	11/21/1979	9.21%
7/12/2017	2.8838	2.88%	2.93%	11/23/1979	9.22%
7/11/2017	2.9234	2.92%	2.93%	11/26/1979	9.23%
7/10/2017	2.9265	2.93%	2.93%	11/27/1979	9.23%
7/7/2017	2.9289	2.93%	2.92%	11/28/1979	9.24%
7/6/2017	2.9016	2.90%	2.92%	11/29/1979	9.24%
7/5/2017	2.8469	2.85%	2.92%	11/30/1979	9.25%
7/4/2017	2.8669	2.87%	2.91%	12/3/1979	9.26%
7/3/2017	2.8669	2.87%	2.91%	12/4/1979	9.26%

6/30/2017	2.8348	2.83%	2.91%	12/5/1979	9.27%
6/29/2017	2.8135	2.81%	2.91%	12/6/1979	9.27%
6/28/2017	2.781	2.78%	2.90%	12/7/1979	9.28%
6/27/2017	2.7518	2.75%	2.90%	12/10/1979	9.28%
6/26/2017	2.697	2.70%	2.90%	12/11/1979	9.29%
6/23/2017	2.7155	2.72%	2.90%	12/12/1979	9.29%
6/22/2017	2.7163	2.72%	2.90%	12/13/1979	9.30%
6/21/2017	2.7274	2.73%	2.90%	12/14/1979	9.30%
6/20/2017	2.7385	2.74%	2.89%	12/17/1979	9.31%
6/19/2017	2.7849	2.78%	2.89%	12/18/1979	9.31%
6/16/2017	2.7752	2.78%	2.89%	12/19/1979	9.32%
6/15/2017	2.7872	2.79%	2.89%	12/20/1979	9.32%
6/14/2017	2.7692	2.77%	2.89%	12/21/1979	9.33%
6/13/2017	2.8648	2.86%	2.88%	12/24/1979	9.34%
6/12/2017	2.8694	2.87%	2.88%	12/26/1979	9.34%
6/9/2017	2.8556	2.86%	2.88%	12/27/1979	9.35%
6/8/2017	2.851	2.85%	2.88%	12/28/1979	9.35%
6/7/2017	2.8366	2.84%	2.87%	12/31/1979	9.36%
6/6/2017	2.8115	2.81%	2.87%	1/2/1980	9.36%
6/5/2017	2.8366	2.84%	2.87%	1/3/1980	9.37%
6/2/2017	2.81	2.81%	2.86%	1/4/1980	9.38%
6/1/2017	2.8626	2.86%	2.86%	1/7/1980	9.38%
5/31/2017	2.8634	2.86%	2.86%	1/8/1980	9.39%
5/30/2017	2.8772	2.88%	2.85%	1/9/1980	9.40%
5/29/2017	2.912	2.91%	2.85%	1/10/1980	9.40%
5/26/2017	2.912	2.91%	2.85%	1/11/1980	9.41%
5/25/2017	2.9206	2.92%	2.84%	1/14/1980	9.42%
5/24/2017	2.9245	2.92%	2.84%	1/15/1980	9.42%
5/23/2017	2.9432	2.94%	2.84%	1/16/1980	9.43%
5/22/2017	2.9136	2.91%	2.83%	1/17/1980	9.44%
5/19/2017	2.8966	2.90%	2.83%	1/18/1980	9.45%
5/18/2017	2.9005	2.90%	2.83%	1/21/1980	9.45%
5/17/2017	2.916	2.92%	2.83%	1/22/1980	9.46%
5/16/2017	2.9921	2.99%	2.82%	1/23/1980	9.47%
5/15/2017	3.0064	3.01%	2.82%	1/24/1980	9.48%
5/12/2017	2.9889	2.99%	2.81%	1/25/1980	9.49%
5/11/2017	3.0255	3.03%	2.81%	1/28/1980	9.50%
5/10/2017	3.0407	3.04%	2.81%	1/29/1980	9.51%
5/9/2017	3.0271	3.03%	2.80%	1/30/1980	9.52%
5/8/2017	3.0222	3.02%	2.80%	1/31/1980	9.53%
5/5/2017	2.9832	2.98%	2.80%	2/1/1980	9.54%
5/4/2017	2.9983	3.00%	2.79%	2/4/1980	9.55%
5/3/2017	2.9681	2.97%	2.79%	2/5/1980	9.57%
5/2/2017	2.9689	2.97%	2.78%	2/6/1980	9.58%
5/1/2017	3.0023	3.00%	2.78%	2/7/1980	9.59%
4/28/2017	2.9508	2.95%	2.78%	2/8/1980	9.61%
4/27/2017	2.9642	2.96%	2.77%	2/11/1980	9.62%

4/26/2017	2.9602	2.96%	2.77%	2/13/1980	9.63%
4/25/2017	2.9879	2.99%	2.77%	2/14/1980	9.65%
4/24/2017	2.9288	2.93%	2.76%	2/15/1980	9.66%
4/21/2017	2.9015	2.90%	2.76%	2/19/1980	9.68%
4/20/2017	2.8822	2.88%	2.76%	2/20/1980	9.69%
4/19/2017	2.8729	2.87%	2.75%	2/21/1980	9.71%
4/18/2017	2.8354	2.84%	2.75%	2/22/1980	9.73%
4/17/2017	2.9094	2.91%	2.75%	2/25/1980	9.75%
4/14/2017	2.8923	2.89%	2.74%	2/26/1980	9.76%
4/13/2017	2.8923	2.89%	2.74%	2/27/1980	9.78%
4/12/2017	2.8861	2.89%	2.74%	2/28/1980	9.80%
4/11/2017	2.9289	2.93%	2.73%	2/29/1980	9.81%
4/10/2017	2.9903	2.99%	2.73%	3/3/1980	9.83%
4/7/2017	3.0078	3.01%	2.72%	3/4/1980	9.84%
4/6/2017	2.9864	2.99%	2.72%	3/5/1980	9.86%
4/5/2017	2.9856	2.99%	2.72%	3/6/1980	9.88%
4/4/2017	2.9999	3.00%	2.71%	3/7/1980	9.89%
4/3/2017	2.9532	2.95%	2.71%	3/10/1980	9.91%
3/31/2017	3.0095	3.01%	2.71%	3/11/1980	9.92%
3/30/2017	3.0343	3.03%	2.70%	3/12/1980	9.94%
3/29/2017	2.9856	2.99%	2.70%	3/13/1980	9.95%
3/28/2017	3.0246	3.02%	2.70%	3/14/1980	9.97%
3/27/2017	2.9848	2.98%	2.70%	3/17/1980	9.98%
3/24/2017	3.0134	3.01%	2.69%	3/18/1980	10.00%
3/23/2017	3.0294	3.03%	2.69%	3/19/1980	10.01%
3/22/2017	3.0174	3.02%	2.69%	3/20/1980	10.03%
3/21/2017	3.0343	3.03%	2.68%	3/21/1980	10.05%
3/20/2017	3.077	3.08%	2.68%	3/24/1980	10.06%
3/17/2017	3.1096	3.11%	2.68%	3/25/1980	10.08%
3/16/2017	3.1506	3.15%	2.68%	3/26/1980	10.10%
3/15/2017	3.1071	3.11%	2.67%	3/27/1980	10.12%
3/14/2017	3.1747	3.17%	2.67%	3/28/1980	10.13%
3/13/2017	3.2122	3.21%	2.67%	3/31/1980	10.15%
3/10/2017	3.1647	3.16%	2.66%	4/1/1980	10.17%
3/9/2017	3.1888	3.19%	2.66%	4/2/1980	10.19%
3/8/2017	3.1489	3.15%	2.66%	4/3/1980	10.20%
3/7/2017	3.121	3.12%	2.65%	4/7/1980	10.22%
3/6/2017	3.1046	3.10%	2.65%	4/8/1980	10.23%
3/3/2017	3.0713	3.07%	2.65%	4/9/1980	10.25%
3/2/2017	3.0729	3.07%	2.65%	4/10/1980	10.26%
3/1/2017	3.0608	3.06%	2.64%	4/11/1980	10.27%
2/28/2017	2.9952	3.00%	2.64%	4/14/1980	10.29%
2/27/2017	2.9833	2.98%	2.64%	4/15/1980	10.30%
2/24/2017	2.951	2.95%	2.64%	4/16/1980	10.31%
2/23/2017	3.0127	3.01%	2.64%	4/17/1980	10.32%
2/22/2017	3.0327	3.03%	2.64%	4/18/1980	10.33%
2/21/2017	3.0407	3.04%	2.63%	4/21/1980	10.34%

2/20/2017	3.0231	3.02%	2.63%	4/22/1980	10.35%
2/17/2017	3.0231	3.02%	2.63%	4/23/1980	10.36%
2/16/2017	3.0487	3.05%	2.63%	4/24/1980	10.38%
2/15/2017	3.0777	3.08%	2.62%	4/25/1980	10.39%
2/14/2017	3.0584	3.06%	2.62%	4/28/1980	10.40%
2/13/2017	3.0319	3.03%	2.62%	4/29/1980	10.41%
2/10/2017	3.0056	3.01%	2.62%	4/30/1980	10.42%
2/9/2017	3.0041	3.00%	2.62%	5/1/1980	10.43%
2/8/2017	2.9485	2.95%	2.61%	5/2/1980	10.43%
2/7/2017	3.0179	3.02%	2.61%	5/5/1980	10.44%
2/6/2017	3.0473	3.05%	2.61%	5/6/1980	10.45%
2/3/2017	3.0902	3.09%	2.61%	5/7/1980	10.45%
2/2/2017	3.0877	3.09%	2.61%	5/8/1980	10.46%
2/1/2017	3.0753	3.08%	2.61%	5/9/1980	10.47%
1/31/2017	3.0612	3.06%	2.60%	5/12/1980	10.47%
1/30/2017	3.0785	3.08%	2.60%	5/13/1980	10.48%
1/27/2017	3.0588	3.06%	2.60%	5/14/1980	10.49%
1/26/2017	3.0851	3.09%	2.60%	5/15/1980	10.49%
1/25/2017	3.0967	3.10%	2.60%	5/16/1980	10.50%
1/24/2017	3.0489	3.05%	2.59%	5/19/1980	10.51%
1/23/2017	2.9862	2.99%	2.59%	5/20/1980	10.52%
1/20/2017	3.0488	3.05%	2.59%	5/21/1980	10.52%
1/19/2017	3.0463	3.05%	2.59%	5/22/1980	10.53%
1/18/2017	3.0129	3.01%	2.58%	5/23/1980	10.54%
1/17/2017	2.9317	2.93%	2.58%	5/27/1980	10.54%
1/16/2017	2.9886	2.99%	2.58%	5/28/1980	10.55%
1/13/2017	2.9886	2.99%	2.58%	5/29/1980	10.56%
1/12/2017	2.9604	2.96%	2.58%	5/30/1980	10.56%
1/11/2017	2.9556	2.96%	2.57%	6/2/1980	10.57%
1/10/2017	2.9676	2.97%	2.57%	6/3/1980	10.58%
1/9/2017	2.958	2.96%	2.57%	6/4/1980	10.58%
1/6/2017	3.0088	3.01%	2.57%	6/5/1980	10.59%
1/5/2017	2.9444	2.94%	2.57%	6/6/1980	10.59%
1/4/2017	3.0397	3.04%	2.57%	6/9/1980	10.60%
1/3/2017	3.0462	3.05%	2.56%	6/10/1980	10.60%
1/2/2017	3.0651	3.07%	2.56%	6/11/1980	10.61%
12/30/2016	3.0651	3.07%	2.56%	6/12/1980	10.61%
12/29/2016	3.079	3.08%	2.56%	6/13/1980	10.61%
12/28/2016	3.0931	3.09%	2.55%	6/16/1980	10.61%
12/27/2016	3.133	3.13%	2.55%	6/17/1980	10.62%
12/26/2016	3.1138	3.11%	2.55%	6/18/1980	10.62%
12/23/2016	3.1138	3.11%	2.55%	6/19/1980	10.62%
12/22/2016	3.1271	3.13%	2.55%	6/20/1980	10.62%
12/21/2016	3.1079	3.11%	2.54%	6/23/1980	10.63%
12/20/2016	3.1396	3.14%	2.54%	6/24/1980	10.63%
12/19/2016	3.1204	3.12%	2.54%	6/25/1980	10.63%
12/16/2016	3.1741	3.17%	2.54%	6/26/1980	10.64%

12/15/2016	3.1622	3.16%	2.54%	6/27/1980	10.64%
12/14/2016	3.1799	3.18%	2.53%	6/30/1980	10.65%
12/13/2016	3.1312	3.13%	2.53%	7/1/1980	10.65%
12/12/2016	3.1538	3.15%	2.53%	7/2/1980	10.66%
12/9/2016	3.1529	3.15%	2.53%	7/3/1980	10.66%
12/8/2016	3.1053	3.11%	2.52%	7/7/1980	10.66%
12/7/2016	3.0224	3.02%	2.52%	7/8/1980	10.67%
12/6/2016	3.0788	3.08%	2.52%	7/9/1980	10.67%
12/5/2016	3.064	3.06%	2.52%	7/10/1980	10.68%
12/2/2016	3.0615	3.06%	2.52%	7/11/1980	10.68%
12/1/2016	3.1085	3.11%	2.51%	7/14/1980	10.69%
11/30/2016	3.0337	3.03%	2.51%	7/15/1980	10.70%
11/29/2016	2.9459	2.95%	2.51%	7/16/1980	10.70%
11/28/2016	2.9755	2.98%	2.51%	7/17/1980	10.71%
11/25/2016	3.0045	3.00%	2.51%	7/18/1980	10.71%
11/24/2016	3.0207	3.02%	2.50%	7/21/1980	10.71%
11/23/2016	3.0207	3.02%	2.50%	7/22/1980	10.72%
11/22/2016	2.9996	3.00%	2.50%	7/23/1980	10.72%
11/21/2016	2.9924	2.99%	2.50%	7/24/1980	10.73%
11/18/2016	3.0296	3.03%	2.50%	7/25/1980	10.73%
11/17/2016	3.0117	3.01%	2.49%	7/28/1980	10.74%
11/16/2016	2.9221	2.92%	2.49%	7/29/1980	10.74%
11/15/2016	2.9555	2.96%	2.49%	7/30/1980	10.75%
11/14/2016	3.0117	3.01%	2.49%	7/31/1980	10.75%
11/11/2016	2.935	2.94%	2.49%	8/1/1980	10.76%
11/10/2016	2.9549	2.95%	2.48%	8/4/1980	10.76%
11/9/2016	2.8456	2.85%	2.48%	8/5/1980	10.76%
11/8/2016	2.6156	2.62%	2.48%	8/6/1980	10.77%
11/7/2016	2.6021	2.60%	2.48%	8/7/1980	10.77%
11/4/2016	2.561	2.56%	2.48%	8/8/1980	10.78%
11/3/2016	2.6004	2.60%	2.48%	8/11/1980	10.78%
11/2/2016	2.5672	2.57%	2.48%	8/12/1980	10.78%
11/1/2016	2.5774	2.58%	2.49%	8/13/1980	10.79%
10/31/2016	2.5798	2.58%	2.49%	8/14/1980	10.79%
10/28/2016	2.6154	2.62%	2.49%	8/15/1980	10.79%
10/27/2016	2.6138	2.61%	2.49%	8/18/1980	10.80%
10/26/2016	2.5412	2.54%	2.49%	8/19/1980	10.80%
10/25/2016	2.4985	2.50%	2.49%	8/20/1980	10.81%
10/24/2016	2.5171	2.52%	2.49%	8/21/1980	10.81%
10/21/2016	2.4846	2.48%	2.49%	8/22/1980	10.82%
10/20/2016	2.5039	2.50%	2.50%	8/25/1980	10.82%
10/19/2016	2.5069	2.51%	2.50%	8/26/1980	10.82%
10/18/2016	2.5054	2.51%	2.50%	8/27/1980	10.83%
10/17/2016	2.5216	2.52%	2.50%	8/28/1980	10.83%
10/14/2016	2.5583	2.56%	2.50%	8/29/1980	10.84%
10/13/2016	2.4768	2.48%	2.51%	9/2/1980	10.84%
10/12/2016	2.4991	2.50%	2.51%	9/3/1980	10.84%

10/11/2016	2.5014	2.50%	2.51%	9/4/1980	10.85%
10/10/2016	2.4508	2.45%	2.51%	9/5/1980	10.85%
10/7/2016	2.4508	2.45%	2.51%	9/8/1980	10.85%
10/6/2016	2.4538	2.45%	2.52%	9/9/1980	10.86%
10/5/2016	2.4234	2.42%	2.52%	9/10/1980	10.86%
10/4/2016	2.4098	2.41%	2.52%	9/11/1980	10.87%
10/3/2016	2.3397	2.34%	2.53%	9/12/1980	10.87%
9/30/2016	2.3154	2.32%	2.53%	9/15/1980	10.88%
9/29/2016	2.2767	2.28%	2.53%	9/16/1980	10.89%
9/28/2016	2.2913	2.29%	2.54%	9/17/1980	10.89%
9/27/2016	2.2774	2.28%	2.54%	9/18/1980	10.90%
9/26/2016	2.3205	2.32%	2.54%	9/19/1980	10.90%
9/23/2016	2.3471	2.35%	2.55%	9/22/1980	10.91%
9/22/2016	2.3353	2.34%	2.55%	9/23/1980	10.92%
9/21/2016	2.3738	2.37%	2.55%	9/24/1980	10.93%
9/20/2016	2.4316	2.43%	2.56%	9/25/1980	10.94%
9/19/2016	2.4551	2.46%	2.56%	9/26/1980	10.94%
9/16/2016	2.4452	2.45%	2.56%	9/29/1980	10.95%
9/15/2016	2.4627	2.46%	2.56%	9/30/1980	10.96%
9/14/2016	2.4497	2.45%	2.57%	10/1/1980	10.97%
9/13/2016	2.4634	2.46%	2.57%	10/2/1980	10.97%
9/12/2016	2.3909	2.39%	2.57%	10/3/1980	10.98%
9/9/2016	2.3946	2.39%	2.57%	10/6/1980	10.99%
9/8/2016	2.3036	2.30%	2.58%	10/7/1980	10.99%
9/7/2016	2.2349	2.23%	2.58%	10/8/1980	11.00%
9/6/2016	2.2241	2.22%	2.58%	10/9/1980	11.00%
9/5/2016	2.2782	2.28%	2.59%	10/10/1980	11.01%
9/2/2016	2.2782	2.28%	2.59%	10/14/1980	11.01%
9/1/2016	2.2299	2.23%	2.59%	10/15/1980	11.02%
8/31/2016	2.232	2.23%	2.60%	10/16/1980	11.02%
8/30/2016	2.2292	2.23%	2.60%	10/17/1980	11.03%
8/29/2016	2.2142	2.21%	2.61%	10/20/1980	11.04%
8/26/2016	2.2869	2.29%	2.61%	10/21/1980	11.04%
8/25/2016	2.263	2.26%	2.61%	10/22/1980	11.05%
8/24/2016	2.2471	2.25%	2.62%	10/23/1980	11.06%
8/23/2016	2.2292	2.23%	2.62%	10/24/1980	11.06%
8/22/2016	2.2371	2.24%	2.62%	10/27/1980	11.07%
8/19/2016	2.2869	2.29%	2.63%	10/28/1980	11.08%
8/18/2016	2.2601	2.26%	2.63%	10/29/1980	11.09%
8/17/2016	2.2594	2.26%	2.64%	10/30/1980	11.10%
8/16/2016	2.2978	2.30%	2.64%	10/31/1980	11.11%
8/15/2016	2.2825	2.28%	2.65%	11/3/1980	11.12%
8/12/2016	2.2306	2.23%	2.65%	11/5/1980	11.12%
8/11/2016	2.2722	2.27%	2.65%	11/6/1980	11.13%
8/10/2016	2.2274	2.23%	2.66%	11/7/1980	11.14%
8/9/2016	2.2617	2.26%	2.66%	11/10/1980	11.15%
8/8/2016	2.309	2.31%	2.66%	11/12/1980	11.16%

8/5/2016	2.314	2.31%	2.67%	11/13/1980	11.17%
8/4/2016	2.254	2.25%	2.67%	11/14/1980	11.17%
8/3/2016	2.2963	2.30%	2.67%	11/17/1980	11.18%
8/2/2016	2.3069	2.31%	2.68%	11/18/1980	11.19%
8/1/2016	2.2695	2.27%	2.68%	11/19/1980	11.19%
7/29/2016	2.1827	2.18%	2.68%	11/20/1980	11.20%
7/28/2016	2.2318	2.23%	2.69%	11/21/1980	11.20%
7/27/2016	2.211	2.21%	2.69%	11/24/1980	11.21%
7/26/2016	2.283	2.28%	2.69%	11/25/1980	11.21%
7/25/2016	2.2872	2.29%	2.70%	11/26/1980	11.21%
7/22/2016	2.283	2.28%	2.70%	11/28/1980	11.21%
7/21/2016	2.2908	2.29%	2.70%	12/1/1980	11.22%
7/20/2016	2.2979	2.30%	2.70%	12/2/1980	11.22%
7/19/2016	2.2669	2.27%	2.71%	12/3/1980	11.22%
7/18/2016	2.2944	2.29%	2.71%	12/4/1980	11.22%
7/15/2016	2.2655	2.27%	2.71%	12/5/1980	11.22%
7/14/2016	2.2523	2.25%	2.72%	12/8/1980	11.22%
7/13/2016	2.1721	2.17%	2.72%	12/9/1980	11.22%
7/12/2016	2.2237	2.22%	2.72%	12/10/1980	11.22%
7/11/2016	2.1394	2.14%	2.73%	12/11/1980	11.23%
7/8/2016	2.0983	2.10%	2.73%	12/12/1980	11.23%
7/7/2016	2.1348	2.13%	2.73%	12/15/1980	11.23%
7/6/2016	2.1375	2.14%	2.74%	12/16/1980	11.23%
7/5/2016	2.1545	2.15%	2.74%	12/17/1980	11.23%
7/4/2016	2.2253	2.23%	2.75%	12/18/1980	11.23%
7/1/2016	2.2253	2.23%	2.75%	12/19/1980	11.23%
6/30/2016	2.2847	2.28%	2.75%	12/22/1980	11.23%
6/29/2016	2.3187	2.32%	2.76%	12/23/1980	11.23%
6/28/2016	2.2749	2.27%	2.76%	12/24/1980	11.22%
6/27/2016	2.2644	2.26%	2.76%	12/26/1980	11.22%
6/24/2016	2.4101	2.41%	2.77%	12/29/1980	11.22%
6/23/2016	2.5547	2.55%	2.77%	12/30/1980	11.22%
6/22/2016	2.4999	2.50%	2.77%	12/31/1980	11.22%
6/21/2016	2.5119	2.51%	2.77%	1/2/1981	11.22%
6/20/2016	2.4955	2.50%	2.78%	1/5/1981	11.21%
6/17/2016	2.4196	2.42%	2.78%	1/6/1981	11.21%
6/16/2016	2.3963	2.40%	2.78%	1/7/1981	11.21%
6/15/2016	2.4065	2.41%	2.78%	1/8/1981	11.21%
6/14/2016	2.4233	2.42%	2.79%	1/9/1981	11.21%
6/13/2016	2.4262	2.43%	2.79%	1/12/1981	11.21%
6/10/2016	2.4511	2.45%	2.79%	1/13/1981	11.20%
6/9/2016	2.4873	2.49%	2.79%	1/14/1981	11.20%
6/8/2016	2.5082	2.51%	2.80%	1/15/1981	11.20%
6/7/2016	2.5419	2.54%	2.80%	1/16/1981	11.20%
6/6/2016	2.557	2.56%	2.80%	1/19/1981	11.20%
6/3/2016	2.5097	2.51%	2.80%	1/20/1981	11.20%
6/2/2016	2.5805	2.58%	2.80%	1/21/1981	11.20%

6/1/2016	2.6164	2.62%	2.81%	1/22/1981	11.20%
5/31/2016	2.6479	2.65%	2.81%	1/23/1981	11.20%
5/30/2016	2.6464	2.65%	2.81%	1/26/1981	11.20%
5/27/2016	2.6464	2.65%	2.81%	1/27/1981	11.21%
5/26/2016	2.6409	2.64%	2.81%	1/28/1981	11.21%
5/25/2016	2.6634	2.66%	2.81%	1/29/1981	11.21%
5/24/2016	2.644	2.64%	2.81%	1/30/1981	11.22%
5/23/2016	2.6232	2.62%	2.81%	2/2/1981	11.22%
5/20/2016	2.6286	2.63%	2.81%	2/3/1981	11.23%
5/19/2016	2.6417	2.64%	2.81%	2/4/1981	11.24%
5/18/2016	2.6595	2.66%	2.81%	2/5/1981	11.25%
5/17/2016	2.5994	2.60%	2.82%	2/6/1981	11.25%
5/16/2016	2.5956	2.60%	2.82%	2/9/1981	11.26%
5/13/2016	2.5486	2.55%	2.82%	2/10/1981	11.27%
5/12/2016	2.5983	2.60%	2.82%	2/11/1981	11.28%
5/11/2016	2.5807	2.58%	2.82%	2/13/1981	11.29%
5/10/2016	2.6122	2.61%	2.82%	2/17/1981	11.30%
5/9/2016	2.6083	2.61%	2.82%	2/18/1981	11.31%
5/6/2016	2.6276	2.63%	2.83%	2/19/1981	11.32%
5/5/2016	2.6029	2.60%	2.83%	2/20/1981	11.33%
5/4/2016	2.6322	2.63%	2.83%	2/23/1981	11.34%
5/3/2016	2.6578	2.66%	2.83%	2/24/1981	11.36%
5/2/2016	2.7245	2.72%	2.83%	2/25/1981	11.37%
4/29/2016	2.6781	2.68%	2.83%	2/26/1981	11.38%
4/28/2016	2.6796	2.68%	2.83%	2/27/1981	11.40%
4/27/2016	2.7008	2.70%	2.84%	3/2/1981	11.41%
4/26/2016	2.7539	2.75%	2.84%	3/3/1981	11.42%
4/25/2016	2.7332	2.73%	2.84%	3/4/1981	11.44%
4/22/2016	2.707	2.71%	2.84%	3/5/1981	11.45%
4/21/2016	2.6842	2.68%	2.84%	3/6/1981	11.46%
4/20/2016	2.6538	2.65%	2.84%	3/9/1981	11.47%
4/19/2016	2.5936	2.59%	2.85%	3/10/1981	11.48%
4/18/2016	2.5799	2.58%	2.85%	3/11/1981	11.49%
4/15/2016	2.5593	2.56%	2.85%	3/12/1981	11.50%
4/14/2016	2.6005	2.60%	2.86%	3/13/1981	11.52%
4/13/2016	2.5837	2.58%	2.86%	3/16/1981	11.53%
4/12/2016	2.5989	2.60%	2.86%	3/17/1981	11.54%
4/11/2016	2.5616	2.56%	2.86%	3/18/1981	11.55%
4/8/2016	2.5525	2.55%	2.87%	3/19/1981	11.56%
4/7/2016	2.5149	2.51%	2.87%	3/20/1981	11.57%
4/6/2016	2.5844	2.58%	2.87%	3/23/1981	11.58%
4/5/2016	2.5442	2.54%	2.88%	3/24/1981	11.59%
4/4/2016	2.5966	2.60%	2.88%	3/25/1981	11.60%
4/1/2016	2.5997	2.60%	2.88%	3/26/1981	11.62%
3/31/2016	2.6119	2.61%	2.88%	3/27/1981	11.63%
3/30/2016	2.6528	2.65%	2.89%	3/30/1981	11.65%
3/29/2016	2.5996	2.60%	2.89%	3/31/1981	11.66%

3/28/2016	2.6567	2.66%	2.89%	4/1/1981	11.68%
3/25/2016	2.673	2.67%	2.90%	4/2/1981	11.69%
3/24/2016	2.673	2.67%	2.90%	4/3/1981	11.71%
3/23/2016	2.6582	2.66%	2.90%	4/6/1981	11.73%
3/22/2016	2.7224	2.72%	2.90%	4/7/1981	11.75%
3/21/2016	2.7169	2.72%	2.90%	4/8/1981	11.76%
3/18/2016	2.6753	2.68%	2.90%	4/9/1981	11.78%
3/17/2016	2.6854	2.69%	2.91%	4/10/1981	11.80%
3/16/2016	2.7105	2.71%	2.91%	4/13/1981	11.82%
3/15/2016	2.731	2.73%	2.91%	4/14/1981	11.83%
3/14/2016	2.7318	2.73%	2.91%	4/15/1981	11.85%
3/11/2016	2.7532	2.75%	2.92%	4/16/1981	11.87%
3/10/2016	2.6947	2.69%	2.92%	4/20/1981	11.89%
3/9/2016	2.662	2.66%	2.92%	4/21/1981	11.90%
3/8/2016	2.6348	2.63%	2.92%	4/22/1981	11.92%
3/7/2016	2.7057	2.71%	2.92%	4/23/1981	11.93%
3/4/2016	2.6947	2.69%	2.92%	4/24/1981	11.95%
3/3/2016	2.658	2.66%	2.93%	4/27/1981	11.97%
3/2/2016	2.6845	2.68%	2.93%	4/28/1981	11.98%
3/1/2016	2.6978	2.70%	2.93%	4/29/1981	12.00%
2/29/2016	2.6156	2.62%	2.93%	4/30/1981	12.02%
2/26/2016	2.6363	2.64%	2.93%	5/1/1981	12.03%
2/25/2016	2.5941	2.59%	2.93%	5/4/1981	12.05%
2/24/2016	2.6056	2.61%	2.93%	5/5/1981	12.07%
2/23/2016	2.5789	2.58%	2.94%	5/6/1981	12.09%
2/22/2016	2.604	2.60%	2.94%	5/7/1981	12.11%
2/19/2016	2.6048	2.60%	2.94%	5/8/1981	12.13%
2/18/2016	2.6086	2.61%	2.94%	5/11/1981	12.15%
2/17/2016	2.6875	2.69%	2.94%	5/12/1981	12.16%
2/16/2016	2.6393	2.64%	2.95%	5/13/1981	12.18%
2/15/2016	2.604	2.60%	2.95%	5/14/1981	12.20%
2/12/2016	2.604	2.60%	2.95%	5/15/1981	12.22%
2/11/2016	2.4977	2.50%	2.95%	5/18/1981	12.23%
2/10/2016	2.4872	2.49%	2.95%	5/19/1981	12.25%
2/9/2016	2.5493	2.55%	2.96%	5/20/1981	12.26%
2/8/2016	2.5764	2.58%	2.96%	5/21/1981	12.27%
2/5/2016	2.6683	2.67%	2.96%	5/22/1981	12.29%
2/4/2016	2.6757	2.68%	2.96%	5/26/1981	12.30%
2/3/2016	2.7126	2.71%	2.96%	5/27/1981	12.31%
2/2/2016	2.656	2.66%	2.96%	5/28/1981	12.33%
2/1/2016	2.7618	2.76%	2.96%	5/29/1981	12.34%
1/29/2016	2.7438	2.74%	2.96%	6/1/1981	12.35%
1/28/2016	2.7851	2.79%	2.96%	6/2/1981	12.36%
1/27/2016	2.801	2.80%	2.96%	6/3/1981	12.37%
1/26/2016	2.7844	2.78%	2.96%	6/4/1981	12.38%
1/25/2016	2.7844	2.78%	2.96%	6/5/1981	12.39%
1/22/2016	2.8238	2.82%	2.96%	6/8/1981	12.40%

1/21/2016	2.8109	2.81%	2.96%	6/9/1981	12.41%
1/20/2016	2.753	2.75%	2.95%	6/10/1981	12.42%
1/19/2016	2.8262	2.83%	2.95%	6/11/1981	12.43%
1/18/2016	2.814	2.81%	2.95%	6/12/1981	12.44%
1/15/2016	2.814	2.81%	2.95%	6/15/1981	12.44%
1/14/2016	2.8869	2.89%	2.95%	6/16/1981	12.45%
1/13/2016	2.8822	2.88%	2.95%	6/17/1981	12.46%
1/12/2016	2.8815	2.88%	2.95%	6/18/1981	12.47%
1/11/2016	2.9682	2.97%	2.94%	6/19/1981	12.47%
1/8/2016	2.9094	2.91%	2.94%	6/22/1981	12.48%
1/7/2016	2.9258	2.93%	2.94%	6/23/1981	12.49%
1/6/2016	2.9375	2.94%	2.94%	6/24/1981	12.50%
1/5/2016	2.9951	3.00%	2.94%	6/25/1981	12.51%
1/4/2016	2.9872	2.99%	2.93%	6/26/1981	12.52%
1/1/2016	3.0158	3.02%	2.93%	6/29/1981	12.53%
12/31/2015	3.0158	3.02%	2.93%	6/30/1981	12.54%
12/30/2015	3.0335	3.03%	2.93%	7/1/1981	12.56%
12/29/2015	3.0359	3.04%	2.92%	7/2/1981	12.57%
12/28/2015	2.943	2.94%	2.92%	7/6/1981	12.58%
12/25/2015	2.9603	2.96%	2.92%	7/7/1981	12.59%
12/24/2015	2.9603	2.96%	2.92%	7/8/1981	12.60%
12/23/2015	2.988	2.99%	2.91%	7/9/1981	12.61%
12/22/2015	2.9556	2.96%	2.91%	7/10/1981	12.62%
12/21/2015	2.9103	2.91%	2.91%	7/13/1981	12.63%
12/18/2015	2.922	2.92%	2.91%	7/14/1981	12.64%
12/17/2015	2.9275	2.93%	2.91%	7/15/1981	12.65%
12/16/2015	3.0039	3.00%	2.91%	7/16/1981	12.66%
12/15/2015	2.9856	2.99%	2.91%	7/17/1981	12.67%
12/14/2015	2.9517	2.95%	2.90%	7/20/1981	12.68%
12/11/2015	2.8709	2.87%	2.90%	7/21/1981	12.69%
12/10/2015	2.9675	2.97%	2.90%	7/22/1981	12.70%
12/9/2015	2.9738	2.97%	2.90%	7/23/1981	12.71%
12/8/2015	2.9549	2.95%	2.90%	7/24/1981	12.72%
12/7/2015	2.9612	2.96%	2.90%	7/27/1981	12.73%
12/4/2015	3.0095	3.01%	2.90%	7/28/1981	12.74%
12/3/2015	3.0543	3.05%	2.90%	7/29/1981	12.75%
12/2/2015	2.9081	2.91%	2.89%	7/30/1981	12.77%
12/1/2015	2.9019	2.90%	2.89%	7/31/1981	12.78%
11/30/2015	2.9723	2.97%	2.89%	8/3/1981	12.80%
11/27/2015	2.9968	3.00%	2.89%	8/4/1981	12.81%
11/26/2015	2.9944	2.99%	2.89%	8/5/1981	12.83%
11/25/2015	2.9944	2.99%	2.89%	8/6/1981	12.84%
11/24/2015	3.0024	3.00%	2.88%	8/7/1981	12.85%
11/23/2015	2.992	2.99%	2.88%	8/10/1981	12.87%
11/20/2015	3.0199	3.02%	2.88%	8/11/1981	12.88%
11/19/2015	3.0103	3.01%	2.88%	8/12/1981	12.89%
11/18/2015	3.0423	3.04%	2.88%	8/13/1981	12.90%

11/17/2015	3.0543	3.05%	2.88%	8/14/1981	12.91%
11/16/2015	3.0616	3.06%	2.87%	8/17/1981	12.92%
11/13/2015	3.0519	3.05%	2.87%	8/18/1981	12.93%
11/12/2015	3.0894	3.09%	2.87%	8/19/1981	12.94%
11/11/2015	3.1152	3.12%	2.86%	8/20/1981	12.95%
11/10/2015	3.1152	3.12%	2.86%	8/21/1981	12.96%
11/9/2015	3.1077	3.11%	2.86%	8/24/1981	12.97%
11/6/2015	3.0853	3.09%	2.85%	8/25/1981	12.98%
11/5/2015	3	3.00%	2.85%	8/26/1981	12.99%
11/4/2015	2.9903	2.99%	2.84%	8/27/1981	13.00%
11/3/2015	2.9919	2.99%	2.84%	8/28/1981	13.01%
11/2/2015	2.9437	2.94%	2.84%	8/31/1981	13.02%
10/30/2015	2.9222	2.92%	2.84%	9/1/1981	13.03%
10/29/2015	2.9589	2.96%	2.83%	9/2/1981	13.04%
10/28/2015	2.8788	2.88%	2.83%	9/3/1981	13.05%
10/27/2015	2.8592	2.86%	2.83%	9/4/1981	13.07%
10/26/2015	2.8686	2.87%	2.83%	9/8/1981	13.08%
10/23/2015	2.9008	2.90%	2.82%	9/9/1981	13.09%
10/22/2015	2.8608	2.86%	2.82%	9/10/1981	13.11%
10/21/2015	2.8647	2.86%	2.82%	9/11/1981	13.12%
10/20/2015	2.9166	2.92%	2.82%	9/14/1981	13.13%
10/19/2015	2.8796	2.88%	2.81%	9/15/1981	13.14%
10/16/2015	2.8812	2.88%	2.81%	9/16/1981	13.15%
10/15/2015	2.8624	2.86%	2.81%	9/17/1981	13.16%
10/14/2015	2.8344	2.83%	2.81%	9/18/1981	13.17%
10/13/2015	2.8843	2.88%	2.81%	9/21/1981	13.17%
10/12/2015	2.9174	2.92%	2.81%	9/22/1981	13.18%
10/9/2015	2.9174	2.92%	2.80%	9/23/1981	13.20%
10/8/2015	2.9397	2.94%	2.80%	9/24/1981	13.21%
10/7/2015	2.8945	2.89%	2.80%	9/25/1981	13.22%
10/6/2015	2.8686	2.87%	2.80%	9/28/1981	13.23%
10/5/2015	2.8969	2.90%	2.80%	9/29/1981	13.24%
10/2/2015	2.8274	2.83%	2.80%	9/30/1981	13.25%
10/1/2015	2.8499	2.85%	2.80%	10/1/1981	13.26%
9/30/2015	2.8538	2.85%	2.80%	10/2/1981	13.27%
9/29/2015	2.853	2.85%	2.80%	10/5/1981	13.28%
9/28/2015	2.8757	2.88%	2.80%	10/6/1981	13.29%
9/25/2015	2.9556	2.96%	2.80%	10/7/1981	13.30%
9/24/2015	2.9166	2.92%	2.80%	10/8/1981	13.32%
9/23/2015	2.9452	2.95%	2.80%	10/9/1981	13.33%
9/22/2015	2.9428	2.94%	2.80%	10/13/1981	13.34%
9/21/2015	3.0216	3.02%	2.80%	10/14/1981	13.35%
9/18/2015	2.9356	2.94%	2.79%	10/15/1981	13.37%
9/17/2015	3.0054	3.01%	2.79%	10/16/1981	13.38%
9/16/2015	3.0822	3.08%	2.79%	10/19/1981	13.39%
9/15/2015	3.0674	3.07%	2.79%	10/20/1981	13.41%
9/14/2015	2.9555	2.96%	2.79%	10/21/1981	13.42%

9/11/2015	2.9524	2.95%	2.79%	10/22/1981	13.44%
9/10/2015	2.9852	2.99%	2.79%	10/23/1981	13.45%
9/9/2015	2.9611	2.96%	2.79%	10/26/1981	13.47%
9/8/2015	2.9555	2.96%	2.79%	10/27/1981	13.48%
9/7/2015	2.8836	2.88%	2.79%	10/28/1981	13.50%
9/4/2015	2.8836	2.88%	2.79%	10/29/1981	13.51%
9/3/2015	2.9348	2.93%	2.79%	10/30/1981	13.52%
9/2/2015	2.9539	2.95%	2.79%	11/2/1981	13.53%
9/1/2015	2.915	2.92%	2.79%	11/4/1981	13.54%
8/31/2015	2.9619	2.96%	2.79%	11/5/1981	13.55%
8/28/2015	2.9119	2.91%	2.79%	11/6/1981	13.56%
8/27/2015	2.9237	2.92%	2.79%	11/9/1981	13.57%
8/26/2015	2.9316	2.93%	2.79%	11/10/1981	13.57%
8/25/2015	2.7992	2.80%	2.79%	11/12/1981	13.58%
8/24/2015	2.7293	2.73%	2.79%	11/13/1981	13.58%
8/21/2015	2.7233	2.72%	2.80%	11/16/1981	13.59%
8/20/2015	2.7429	2.74%	2.80%	11/17/1981	13.59%
8/19/2015	2.8153	2.82%	2.80%	11/18/1981	13.59%
8/18/2015	2.8555	2.86%	2.80%	11/19/1981	13.60%
8/17/2015	2.8176	2.82%	2.80%	11/20/1981	13.60%
8/14/2015	2.8416	2.84%	2.80%	11/23/1981	13.60%
8/13/2015	2.855	2.86%	2.80%	11/24/1981	13.61%
8/12/2015	2.8397	2.84%	2.81%	11/25/1981	13.61%
8/11/2015	2.8092	2.81%	2.81%	11/27/1981	13.61%
8/10/2015	2.896	2.90%	2.81%	11/30/1981	13.61%
8/7/2015	2.8191	2.82%	2.81%	12/1/1981	13.61%
8/6/2015	2.8914	2.89%	2.81%	12/2/1981	13.61%
8/5/2015	2.9437	2.94%	2.81%	12/3/1981	13.61%
8/4/2015	2.8968	2.90%	2.81%	12/4/1981	13.61%
8/3/2015	2.852	2.85%	2.81%	12/7/1981	13.61%
7/31/2015	2.9061	2.91%	2.81%	12/8/1981	13.61%
7/30/2015	2.9429	2.94%	2.81%	12/9/1981	13.62%
7/29/2015	2.9975	3.00%	2.81%	12/10/1981	13.62%
7/28/2015	2.965	2.97%	2.81%	12/11/1981	13.63%
7/27/2015	2.9327	2.93%	2.81%	12/14/1981	13.63%
7/24/2015	2.9618	2.96%	2.81%	12/15/1981	13.63%
7/23/2015	2.9673	2.97%	2.81%	12/16/1981	13.63%
7/22/2015	3.0367	3.04%	2.81%	12/17/1981	13.63%
7/21/2015	3.0617	3.06%	2.81%	12/18/1981	13.63%
7/20/2015	3.0942	3.09%	2.81%	12/21/1981	13.64%
7/17/2015	3.0828	3.08%	2.81%	12/22/1981	13.64%
7/16/2015	3.1089	3.11%	2.81%	12/23/1981	13.65%
7/15/2015	3.1385	3.14%	2.81%	12/24/1981	13.65%
7/14/2015	3.1958	3.20%	2.81%	12/28/1981	13.66%
7/13/2015	3.2362	3.24%	2.81%	12/29/1981	13.66%
7/10/2015	3.1899	3.19%	2.81%	12/30/1981	13.67%
7/9/2015	3.1203	3.12%	2.81%	12/31/1981	13.67%

7/8/2015	2.9745	2.97%	2.81%	1/5/1982	13.68%
7/7/2015	3.0399	3.04%	2.81%	1/6/1982	13.69%
7/6/2015	3.0827	3.08%	2.81%	1/7/1982	13.70%
7/3/2015	3.1865	3.19%	2.81%	1/8/1982	13.71%
7/2/2015	3.1865	3.19%	2.81%	1/11/1982	13.72%
7/1/2015	3.2015	3.20%	2.81%	1/12/1982	13.73%
6/30/2015	3.1236	3.12%	2.81%	1/13/1982	13.74%
6/29/2015	3.0998	3.10%	2.81%	1/14/1982	13.75%
6/26/2015	3.2402	3.24%	2.81%	1/15/1982	13.76%
6/25/2015	3.1756	3.18%	2.81%	1/18/1982	13.76%
6/24/2015	3.1458	3.15%	2.82%	1/19/1982	13.77%
6/23/2015	3.1964	3.20%	2.82%	1/20/1982	13.78%
6/22/2015	3.1606	3.16%	2.82%	1/21/1982	13.79%
6/19/2015	3.0471	3.05%	2.82%	1/22/1982	13.79%
6/18/2015	3.1292	3.13%	2.82%	1/25/1982	13.80%
6/17/2015	3.0932	3.09%	2.82%	1/26/1982	13.80%
6/16/2015	3.0407	3.04%	2.82%	1/27/1982	13.81%
6/15/2015	3.0851	3.09%	2.82%	1/28/1982	13.81%
6/12/2015	3.103	3.10%	2.82%	1/29/1982	13.82%
6/11/2015	3.0957	3.10%	2.82%	2/1/1982	13.82%
6/10/2015	3.2156	3.22%	2.82%	2/2/1982	13.83%
6/9/2015	3.1663	3.17%	2.82%	2/3/1982	13.84%
6/8/2015	3.1144	3.11%	2.82%	2/4/1982	13.84%
6/5/2015	3.1136	3.11%	2.82%	2/5/1982	13.85%
6/4/2015	3.0407	3.04%	2.82%	2/8/1982	13.86%
6/3/2015	3.1022	3.10%	2.82%	2/9/1982	13.86%
6/2/2015	3.0143	3.01%	2.82%	2/10/1982	13.87%
6/1/2015	2.9338	2.93%	2.82%	2/11/1982	13.88%
5/29/2015	2.8818	2.88%	2.83%	2/16/1982	13.88%
5/28/2015	2.8873	2.89%	2.83%	2/17/1982	13.89%
5/27/2015	2.8673	2.87%	2.83%	2/18/1982	13.89%
5/26/2015	2.8981	2.90%	2.83%	2/19/1982	13.89%
5/25/2015	2.9841	2.98%	2.83%	2/22/1982	13.89%
5/22/2015	2.9841	2.98%	2.83%	2/23/1982	13.89%
5/21/2015	2.9881	2.99%	2.83%	2/24/1982	13.89%
5/20/2015	3.0471	3.05%	2.83%	2/25/1982	13.89%
5/19/2015	3.0753	3.08%	2.84%	2/26/1982	13.89%
5/18/2015	3.0295	3.03%	2.84%	3/1/1982	13.89%
5/15/2015	2.9292	2.93%	2.84%	3/2/1982	13.89%
5/14/2015	3.0497	3.05%	2.84%	3/3/1982	13.88%
5/13/2015	3.087	3.09%	2.84%	3/4/1982	13.88%
5/12/2015	3.0127	3.01%	2.84%	3/5/1982	13.88%
5/11/2015	3.041	3.04%	2.84%	3/8/1982	13.88%
5/8/2015	2.9006	2.90%	2.84%	3/9/1982	13.88%
5/7/2015	2.9105	2.91%	2.85%	3/10/1982	13.88%
5/6/2015	2.9929	2.99%	2.85%	3/11/1982	13.88%
5/5/2015	2.9122	2.91%	2.85%	3/12/1982	13.88%

5/4/2015	2.8765	2.88%	2.85%	3/15/1982	13.88%
5/1/2015	2.8273	2.83%	2.85%	3/16/1982	13.88%
4/30/2015	2.7404	2.74%	2.85%	3/17/1982	13.88%
4/29/2015	2.7523	2.75%	2.86%	3/18/1982	13.88%
4/28/2015	2.7031	2.70%	2.86%	3/19/1982	13.88%
4/27/2015	2.6121	2.61%	2.86%	3/22/1982	13.89%
4/24/2015	2.6098	2.61%	2.87%	3/23/1982	13.89%
4/23/2015	2.653	2.65%	2.87%	3/24/1982	13.89%
4/22/2015	2.6616	2.66%	2.87%	3/25/1982	13.89%
4/21/2015	2.5806	2.58%	2.88%	3/26/1982	13.89%
4/20/2015	2.5624	2.56%	2.88%	3/29/1982	13.90%
4/17/2015	2.5194	2.52%	2.88%	3/30/1982	13.90%
4/16/2015	2.5753	2.58%	2.89%	3/31/1982	13.91%
4/15/2015	2.5397	2.54%	2.89%	4/1/1982	13.91%
4/14/2015	2.5427	2.54%	2.90%	4/2/1982	13.91%
4/13/2015	2.573	2.57%	2.90%	4/5/1982	13.92%
4/10/2015	2.5791	2.58%	2.90%	4/6/1982	13.92%
4/9/2015	2.5981	2.60%	2.91%	4/7/1982	13.93%
4/8/2015	2.5291	2.53%	2.91%	4/8/1982	13.93%
4/7/2015	2.5179	2.52%	2.92%	4/12/1982	13.94%
4/6/2015	2.5532	2.55%	2.92%	4/13/1982	13.94%
4/3/2015	2.4858	2.49%	2.93%	4/14/1982	13.94%
4/2/2015	2.5321	2.53%	2.93%	4/15/1982	13.94%
4/1/2015	2.4651	2.47%	2.93%	4/16/1982	13.94%
3/31/2015	2.5359	2.54%	2.94%	4/19/1982	13.94%
3/30/2015	2.5479	2.55%	2.94%	4/20/1982	13.94%
3/27/2015	2.5404	2.54%	2.95%	4/21/1982	13.94%
3/26/2015	2.5798	2.58%	2.95%	4/22/1982	13.94%
3/25/2015	2.5074	2.51%	2.96%	4/23/1982	13.94%
3/24/2015	2.4643	2.46%	2.96%	4/26/1982	13.94%
3/23/2015	2.5141	2.51%	2.97%	4/27/1982	13.94%
3/20/2015	2.5059	2.51%	2.97%	4/28/1982	13.94%
3/19/2015	2.5291	2.53%	2.98%	4/29/1982	13.94%
3/18/2015	2.5104	2.51%	2.98%	4/30/1982	13.94%
3/17/2015	2.6026	2.60%	2.98%	5/3/1982	13.94%
3/16/2015	2.6449	2.64%	2.99%	5/4/1982	13.94%
3/13/2015	2.6987	2.70%	2.99%	5/5/1982	13.94%
3/12/2015	2.6995	2.70%	3.00%	5/6/1982	13.94%
3/11/2015	2.6853	2.69%	3.00%	5/7/1982	13.94%
3/10/2015	2.7231	2.72%	3.00%	5/10/1982	13.94%
3/9/2015	2.798	2.80%	3.01%	5/11/1982	13.93%
3/6/2015	2.8409	2.84%	3.01%	5/12/1982	13.93%
3/5/2015	2.7285	2.73%	3.01%	5/13/1982	13.93%
3/4/2015	2.7198	2.72%	3.02%	5/14/1982	13.92%
3/3/2015	2.7143	2.71%	3.02%	5/17/1982	13.92%
3/2/2015	2.6814	2.68%	3.02%	5/18/1982	13.92%
2/27/2015	2.5903	2.59%	3.03%	5/19/1982	13.92%

2/26/2015	2.6294	2.63%	3.03%	5/20/1982	13.91%
2/25/2015	2.5698	2.57%	3.03%	5/21/1982	13.91%
2/24/2015	2.5918	2.59%	3.04%	5/24/1982	13.90%
2/23/2015	2.6572	2.66%	3.04%	5/25/1982	13.90%
2/20/2015	2.7142	2.71%	3.05%	5/26/1982	13.90%
2/19/2015	2.7339	2.73%	3.05%	5/27/1982	13.89%
2/18/2015	2.7102	2.71%	3.05%	5/28/1982	13.89%
2/17/2015	2.7268	2.73%	3.05%	6/1/1982	13.89%
2/16/2015	2.6478	2.65%	3.06%	6/2/1982	13.89%
2/13/2015	2.6478	2.65%	3.06%	6/3/1982	13.89%
2/12/2015	2.5755	2.58%	3.07%	6/4/1982	13.88%
2/11/2015	2.5863	2.59%	3.07%	6/7/1982	13.88%
2/10/2015	2.5763	2.58%	3.08%	6/8/1982	13.88%
2/9/2015	2.5528	2.55%	3.08%	6/9/1982	13.88%
2/6/2015	2.5287	2.53%	3.08%	6/10/1982	13.88%
2/5/2015	2.4318	2.43%	3.09%	6/11/1982	13.88%
2/4/2015	2.3481	2.35%	3.09%	6/14/1982	13.88%
2/3/2015	2.3792	2.38%	3.10%	6/15/1982	13.88%
2/2/2015	2.2503	2.25%	3.10%	6/16/1982	13.87%
1/30/2015	2.2222	2.22%	3.11%	6/17/1982	13.87%
1/29/2015	2.3148	2.31%	3.12%	6/18/1982	13.87%
1/28/2015	2.2908	2.29%	3.12%	6/21/1982	13.87%
1/27/2015	2.3999	2.40%	3.13%	6/22/1982	13.86%
1/26/2015	2.3972	2.40%	3.13%	6/23/1982	13.86%
1/23/2015	2.3735	2.37%	3.14%	6/24/1982	13.86%
1/22/2015	2.4385	2.44%	3.14%	6/25/1982	13.86%
1/21/2015	2.4614	2.46%	3.15%	6/28/1982	13.85%
1/20/2015	2.3777	2.38%	3.15%	6/29/1982	13.85%
1/19/2015	2.4531	2.45%	3.16%	6/30/1982	13.85%
1/16/2015	2.4531	2.45%	3.17%	7/1/1982	13.84%
1/15/2015	2.3677	2.37%	3.17%	7/2/1982	13.84%
1/14/2015	2.4685	2.47%	3.18%	7/6/1982	13.84%
1/13/2015	2.4992	2.50%	3.18%	7/7/1982	13.83%
1/12/2015	2.4965	2.50%	3.19%	7/8/1982	13.83%
1/9/2015	2.5281	2.53%	3.19%	7/9/1982	13.82%
1/8/2015	2.5993	2.60%	3.20%	7/12/1982	13.82%
1/7/2015	2.5289	2.53%	3.20%	7/13/1982	13.82%
1/6/2015	2.5023	2.50%	3.21%	7/14/1982	13.82%
1/5/2015	2.5987	2.60%	3.21%	7/15/1982	13.81%
1/2/2015	2.688	2.69%	3.22%	7/16/1982	13.81%
1/1/2015	2.7518	2.75%	3.22%	7/19/1982	13.80%
12/31/2014	2.7518	2.75%	3.23%	7/20/1982	13.79%
12/30/2014	2.7563	2.76%	3.23%	7/21/1982	13.78%
12/29/2014	2.7728	2.77%	3.23%	7/22/1982	13.77%
12/26/2014	2.8165	2.82%	3.24%	7/23/1982	13.76%
12/25/2014	2.8341	2.83%	3.24%	7/26/1982	13.75%
12/24/2014	2.8341	2.83%	3.25%	7/27/1982	13.75%

12/23/2014	2.8517	2.85%	3.25%	7/28/1982	13.74%
12/22/2014	2.743	2.74%	3.25%	7/29/1982	13.74%
12/19/2014	2.7542	2.75%	3.26%	7/30/1982	13.73%
12/18/2014	2.8182	2.82%	3.26%	8/2/1982	13.72%
12/17/2014	2.7275	2.73%	3.27%	8/3/1982	13.72%
12/16/2014	2.6906	2.69%	3.27%	8/4/1982	13.71%
12/15/2014	2.7468	2.75%	3.28%	8/5/1982	13.71%
12/12/2014	2.7372	2.74%	3.28%	8/6/1982	13.70%
12/11/2014	2.8069	2.81%	3.29%	8/9/1982	13.70%
12/10/2014	2.832	2.83%	3.29%	8/10/1982	13.69%
12/9/2014	2.8702	2.87%	3.30%	8/11/1982	13.68%
12/8/2014	2.9042	2.90%	3.30%	8/12/1982	13.67%
12/5/2014	2.9667	2.97%	3.30%	8/13/1982	13.66%
12/4/2014	2.9361	2.94%	3.31%	8/16/1982	13.65%
12/3/2014	2.9849	2.98%	3.31%	8/17/1982	13.64%
12/2/2014	3.0127	3.01%	3.31%	8/18/1982	13.63%
12/1/2014	2.9628	2.96%	3.32%	8/19/1982	13.61%
11/28/2014	2.8888	2.89%	3.32%	8/20/1982	13.60%
11/27/2014	2.9542	2.95%	3.32%	8/23/1982	13.59%
11/26/2014	2.9542	2.95%	3.33%	8/24/1982	13.58%
11/25/2014	2.9605	2.96%	3.33%	8/25/1982	13.57%
11/24/2014	3.0199	3.02%	3.33%	8/26/1982	13.56%
11/21/2014	3.0175	3.02%	3.34%	8/27/1982	13.56%
11/20/2014	3.0543	3.05%	3.34%	8/30/1982	13.55%
11/19/2014	3.0769	3.08%	3.34%	8/31/1982	13.55%
11/18/2014	3.0383	3.04%	3.35%	9/1/1982	13.54%
11/17/2014	3.0624	3.06%	3.35%	9/2/1982	13.54%
11/14/2014	3.0487	3.05%	3.35%	9/3/1982	13.53%
11/13/2014	3.0709	3.07%	3.36%	9/7/1982	13.53%
11/12/2014	3.1046	3.10%	3.36%	9/8/1982	13.52%
11/11/2014	3.0926	3.09%	3.36%	9/9/1982	13.52%
11/10/2014	3.0926	3.09%	3.37%	9/10/1982	13.51%
11/7/2014	3.028	3.03%	3.37%	9/13/1982	13.51%
11/6/2014	3.103	3.10%	3.37%	9/14/1982	13.51%
11/5/2014	3.059	3.06%	3.37%	9/15/1982	13.50%
11/4/2014	3.0478	3.05%	3.38%	9/16/1982	13.50%
11/3/2014	3.0638	3.06%	3.38%	9/17/1982	13.50%
10/31/2014	3.0662	3.07%	3.38%	9/20/1982	13.49%
10/30/2014	3.0463	3.05%	3.38%	9/21/1982	13.48%
10/29/2014	3.0495	3.05%	3.39%	9/22/1982	13.48%
10/28/2014	3.0678	3.07%	3.39%	9/23/1982	13.47%
10/27/2014	3.0368	3.04%	3.39%	9/24/1982	13.46%
10/24/2014	3.0423	3.04%	3.40%	9/27/1982	13.46%
10/23/2014	3.0431	3.04%	3.40%	9/28/1982	13.45%
10/22/2014	2.9904	2.99%	3.41%	9/29/1982	13.44%
10/21/2014	2.9904	2.99%	3.41%	9/30/1982	13.43%
10/20/2014	2.9655	2.97%	3.41%	10/1/1982	13.42%

10/17/2014	2.9678	2.97%	3.42%	10/4/1982	13.42%
10/16/2014	2.9353	2.94%	3.42%	10/5/1982	13.41%
10/15/2014	2.9176	2.92%	3.43%	10/6/1982	13.40%
10/14/2014	2.9531	2.95%	3.43%	10/7/1982	13.39%
10/13/2014	3.0124	3.01%	3.44%	10/8/1982	13.38%
10/10/2014	3.0124	3.01%	3.44%	10/12/1982	13.36%
10/9/2014	3.0496	3.05%	3.45%	10/13/1982	13.35%
10/8/2014	3.0599	3.06%	3.45%	10/14/1982	13.33%
10/7/2014	3.0464	3.05%	3.45%	10/15/1982	13.32%
10/6/2014	3.1273	3.13%	3.46%	10/18/1982	13.30%
10/3/2014	3.1233	3.12%	3.46%	10/19/1982	13.29%
10/2/2014	3.1427	3.14%	3.47%	10/20/1982	13.28%
10/1/2014	3.0919	3.09%	3.47%	10/21/1982	13.26%
9/30/2014	3.1967	3.20%	3.47%	10/22/1982	13.24%
9/29/2014	3.1647	3.16%	3.48%	10/25/1982	13.23%
9/26/2014	3.214	3.21%	3.48%	10/26/1982	13.21%
9/25/2014	3.2115	3.21%	3.48%	10/27/1982	13.20%
9/24/2014	3.279	3.28%	3.49%	10/28/1982	13.18%
9/23/2014	3.2463	3.25%	3.49%	10/29/1982	13.16%
9/22/2014	3.2891	3.29%	3.49%	11/1/1982	13.15%
9/19/2014	3.284	3.28%	3.50%	11/3/1982	13.13%
9/18/2014	3.3476	3.35%	3.50%	11/4/1982	13.11%
9/17/2014	3.369	3.37%	3.50%	11/5/1982	13.09%
9/16/2014	3.3604	3.36%	3.51%	11/8/1982	13.07%
9/15/2014	3.3433	3.34%	3.51%	11/9/1982	13.05%
9/12/2014	3.3441	3.34%	3.51%	11/10/1982	13.03%
9/11/2014	3.2772	3.28%	3.51%	11/12/1982	13.02%
9/10/2014	3.2722	3.27%	3.52%	11/15/1982	13.00%
9/9/2014	3.2338	3.23%	3.52%	11/16/1982	12.98%
9/8/2014	3.2247	3.22%	3.52%	11/17/1982	12.96%
9/5/2014	3.2263	3.23%	3.53%	11/18/1982	12.94%
9/4/2014	3.209	3.21%	3.53%	11/19/1982	12.92%
9/3/2014	3.1419	3.14%	3.53%	11/22/1982	12.91%
9/2/2014	3.1753	3.18%	3.53%	11/23/1982	12.89%
9/1/2014	3.0792	3.08%	3.54%	11/24/1982	12.87%
8/29/2014	3.0792	3.08%	3.54%	11/26/1982	12.85%
8/28/2014	3.0744	3.07%	3.55%	11/29/1982	12.83%
8/27/2014	3.1024	3.10%	3.55%	11/30/1982	12.81%
8/26/2014	3.1623	3.16%	3.55%	12/1/1982	12.79%
8/25/2014	3.1314	3.13%	3.56%	12/2/1982	12.77%
8/22/2014	3.1566	3.16%	3.56%	12/3/1982	12.75%
8/21/2014	3.1884	3.19%	3.56%	12/6/1982	12.73%
8/20/2014	3.2205	3.22%	3.57%	12/7/1982	12.71%
8/19/2014	3.2131	3.21%	3.57%	12/8/1982	12.69%
8/18/2014	3.1983	3.20%	3.57%	12/9/1982	12.68%
8/15/2014	3.1323	3.13%	3.58%	12/10/1982	12.66%
8/14/2014	3.1917	3.19%	3.58%	12/13/1982	12.65%

8/13/2014	3.2432	3.24%	3.58%	12/14/1982	12.63%
8/12/2014	3.2765	3.28%	3.58%	12/15/1982	12.61%
8/11/2014	3.2432	3.24%	3.59%	12/16/1982	12.60%
8/8/2014	3.2303	3.23%	3.59%	12/17/1982	12.58%
8/7/2014	3.2239	3.22%	3.59%	12/20/1982	12.57%
8/6/2014	3.27	3.27%	3.59%	12/21/1982	12.56%
8/5/2014	3.2831	3.28%	3.60%	12/22/1982	12.54%
8/4/2014	3.288	3.29%	3.60%	12/23/1982	12.53%
8/1/2014	3.2807	3.28%	3.60%	12/27/1982	12.51%
7/31/2014	3.3167	3.32%	3.60%	12/28/1982	12.50%
7/30/2014	3.3126	3.31%	3.60%	12/29/1982	12.48%
7/29/2014	3.2248	3.22%	3.60%	12/30/1982	12.47%
7/28/2014	3.2547	3.25%	3.61%	12/31/1982	12.45%
7/25/2014	3.2385	3.24%	3.61%	1/3/1983	12.43%
7/24/2014	3.2954	3.30%	3.61%	1/4/1983	12.42%
7/23/2014	3.2636	3.26%	3.61%	1/5/1983	12.40%
7/22/2014	3.2498	3.25%	3.61%	1/6/1983	12.39%
7/21/2014	3.2563	3.26%	3.62%	1/7/1983	12.37%
7/18/2014	3.2881	3.29%	3.62%	1/10/1983	12.36%
7/17/2014	3.2661	3.27%	3.62%	1/11/1983	12.34%
7/16/2014	3.3374	3.34%	3.62%	1/12/1983	12.33%
7/15/2014	3.3673	3.37%	3.63%	1/13/1983	12.31%
7/14/2014	3.3715	3.37%	3.63%	1/14/1983	12.30%
7/11/2014	3.3366	3.34%	3.63%	1/17/1983	12.28%
7/10/2014	3.3698	3.37%	3.63%	1/18/1983	12.27%
7/9/2014	3.374	3.37%	3.63%	1/19/1983	12.25%
7/8/2014	3.3723	3.37%	3.63%	1/20/1983	12.24%
7/7/2014	3.4362	3.44%	3.64%	1/21/1983	12.22%
7/4/2014	3.4694	3.47%	3.64%	1/24/1983	12.21%
7/3/2014	3.4694	3.47%	3.64%	1/25/1983	12.19%
7/2/2014	3.4609	3.46%	3.64%	1/26/1983	12.18%
7/1/2014	3.3983	3.40%	3.64%	1/27/1983	12.17%
6/30/2014	3.3599	3.36%	3.64%	1/28/1983	12.16%
6/27/2014	3.3665	3.37%	3.64%	1/31/1983	12.14%
6/26/2014	3.3557	3.36%	3.64%	2/1/1983	12.13%
6/25/2014	3.3815	3.38%	3.65%	2/2/1983	12.12%
6/24/2014	3.3991	3.40%	3.65%	2/3/1983	12.11%
6/23/2014	3.4549	3.45%	3.65%	2/4/1983	12.10%
6/20/2014	3.4337	3.43%	3.65%	2/7/1983	12.09%
6/19/2014	3.466	3.47%	3.66%	2/8/1983	12.08%
6/18/2014	3.4008	3.40%	3.66%	2/9/1983	12.07%
6/17/2014	3.4421	3.44%	3.66%	2/10/1983	12.06%
6/16/2014	3.3958	3.40%	3.66%	2/11/1983	12.05%
6/13/2014	3.4134	3.41%	3.66%	2/14/1983	12.03%
6/12/2014	3.4101	3.41%	3.67%	2/15/1983	12.02%
6/11/2014	3.4659	3.47%	3.67%	2/16/1983	12.01%
6/10/2014	3.4779	3.48%	3.67%	2/17/1983	12.00%

6/9/2014	3.4388	3.44%	3.67%	2/18/1983	11.98%
6/6/2014	3.432	3.43%	3.67%	2/22/1983	11.97%
6/5/2014	3.4362	3.44%	3.67%	2/23/1983	11.96%
6/4/2014	3.4396	3.44%	3.68%	2/24/1983	11.95%
6/3/2014	3.4379	3.44%	3.68%	2/25/1983	11.93%
6/2/2014	3.3691	3.37%	3.68%	2/28/1983	11.92%
5/30/2014	3.3277	3.33%	3.68%	3/1/1983	11.91%
5/29/2014	3.3228	3.32%	3.68%	3/2/1983	11.89%
5/28/2014	3.2942	3.29%	3.69%	3/3/1983	11.88%
5/27/2014	3.3608	3.36%	3.69%	3/4/1983	11.86%
5/26/2014	3.3933	3.39%	3.69%	3/7/1983	11.85%
5/23/2014	3.3933	3.39%	3.69%	3/8/1983	11.84%
5/22/2014	3.4261	3.43%	3.70%	3/9/1983	11.82%
5/21/2014	3.4118	3.41%	3.70%	3/10/1983	11.81%
5/20/2014	3.3833	3.38%	3.70%	3/11/1983	11.80%
5/19/2014	3.3858	3.39%	3.70%	3/14/1983	11.79%
5/16/2014	3.346	3.35%	3.70%	3/15/1983	11.77%
5/15/2014	3.3245	3.32%	3.70%	3/16/1983	11.76%
5/14/2014	3.3767	3.38%	3.71%	3/17/1983	11.75%
5/13/2014	3.4464	3.45%	3.71%	3/18/1983	11.73%
5/12/2014	3.4967	3.50%	3.71%	3/21/1983	11.72%
5/9/2014	3.4634	3.46%	3.71%	3/22/1983	11.70%
5/8/2014	3.4344	3.43%	3.71%	3/23/1983	11.69%
5/7/2014	3.4025	3.40%	3.71%	3/24/1983	11.67%
5/6/2014	3.383	3.38%	3.71%	3/25/1983	11.66%
5/5/2014	3.4074	3.41%	3.72%	3/28/1983	11.64%
5/2/2014	3.3668	3.37%	3.72%	3/29/1983	11.63%
5/1/2014	3.4132	3.41%	3.72%	3/30/1983	11.61%
4/30/2014	3.4593	3.46%	3.72%	3/31/1983	11.59%
4/29/2014	3.4867	3.49%	3.72%	4/4/1983	11.58%
4/28/2014	3.4859	3.49%	3.72%	4/5/1983	11.56%
4/25/2014	3.4428	3.44%	3.72%	4/6/1983	11.54%
4/24/2014	3.4527	3.45%	3.72%	4/7/1983	11.53%
4/23/2014	3.4784	3.48%	3.72%	4/8/1983	11.51%
4/22/2014	3.4942	3.49%	3.72%	4/11/1983	11.49%
4/21/2014	3.5219	3.52%	3.72%	4/12/1983	11.47%
4/18/2014	3.5219	3.52%	3.72%	4/13/1983	11.45%
4/17/2014	3.5219	3.52%	3.72%	4/14/1983	11.43%
4/16/2014	3.4437	3.44%	3.72%	4/15/1983	11.41%
4/15/2014	3.4611	3.46%	3.73%	4/18/1983	11.39%
4/14/2014	3.4876	3.49%	3.73%	4/19/1983	11.38%
4/11/2014	3.4827	3.48%	3.73%	4/20/1983	11.36%
4/10/2014	3.5194	3.52%	3.73%	4/21/1983	11.34%
4/9/2014	3.5726	3.57%	3.73%	4/22/1983	11.33%
4/8/2014	3.5379	3.54%	3.73%	4/25/1983	11.31%
4/7/2014	3.5574	3.56%	3.73%	4/26/1983	11.29%
4/4/2014	3.5837	3.58%	3.73%	4/27/1983	11.28%

4/3/2014	3.6291	3.63%	3.73%	4/28/1983	11.26%
4/2/2014	3.6473	3.65%	3.73%	4/29/1983	11.24%
4/1/2014	3.6059	3.61%	3.73%	5/2/1983	11.23%
3/31/2014	3.5583	3.56%	3.73%	5/3/1983	11.21%
3/28/2014	3.5473	3.55%	3.73%	5/4/1983	11.20%
3/27/2014	3.5271	3.53%	3.73%	5/5/1983	11.18%
3/26/2014	3.5422	3.54%	3.73%	5/6/1983	11.17%
3/25/2014	3.5914	3.59%	3.73%	5/9/1983	11.15%
3/24/2014	3.5617	3.56%	3.72%	5/10/1983	11.14%
3/21/2014	3.6068	3.61%	3.72%	5/11/1983	11.12%
3/20/2014	3.6629	3.66%	3.72%	5/12/1983	11.11%
3/19/2014	3.6568	3.66%	3.72%	5/13/1983	11.09%
3/18/2014	3.6137	3.61%	3.72%	5/16/1983	11.08%
3/17/2014	3.6283	3.63%	3.72%	5/17/1983	11.06%
3/14/2014	3.5992	3.60%	3.72%	5/18/1983	11.05%
3/13/2014	3.5906	3.59%	3.71%	5/19/1983	11.04%
3/12/2014	3.6733	3.67%	3.71%	5/20/1983	11.02%
3/11/2014	3.7092	3.71%	3.71%	5/23/1983	11.01%
3/10/2014	3.7215	3.72%	3.71%	5/24/1983	11.00%
3/7/2014	3.7206	3.72%	3.71%	5/25/1983	10.98%
3/6/2014	3.6899	3.69%	3.70%	5/26/1983	10.97%
3/5/2014	3.6473	3.65%	3.70%	5/27/1983	10.96%
3/4/2014	3.6473	3.65%	3.70%	5/31/1983	10.95%
3/3/2014	3.5542	3.55%	3.70%	6/1/1983	10.94%
2/28/2014	3.5822	3.58%	3.70%	6/2/1983	10.93%
2/27/2014	3.5916	3.59%	3.69%	6/3/1983	10.92%
2/26/2014	3.6249	3.62%	3.69%	6/6/1983	10.91%
2/25/2014	3.6586	3.66%	3.69%	6/7/1983	10.90%
2/24/2014	3.6986	3.70%	3.69%	6/8/1983	10.89%
2/21/2014	3.6934	3.69%	3.69%	6/9/1983	10.89%
2/20/2014	3.7232	3.72%	3.68%	6/10/1983	10.88%
2/19/2014	3.7127	3.71%	3.68%	6/13/1983	10.87%
2/18/2014	3.6777	3.68%	3.68%	6/14/1983	10.87%
2/17/2014	3.6969	3.70%	3.67%	6/15/1983	10.86%
2/14/2014	3.6969	3.70%	3.67%	6/16/1983	10.85%
2/13/2014	3.6829	3.68%	3.67%	6/17/1983	10.84%
2/12/2014	3.7201	3.72%	3.67%	6/20/1983	10.83%
2/11/2014	3.688	3.69%	3.66%	6/21/1983	10.82%
2/10/2014	3.6503	3.65%	3.66%	6/22/1983	10.82%
2/7/2014	3.6726	3.67%	3.65%	6/23/1983	10.81%
2/6/2014	3.6683	3.67%	3.65%	6/24/1983	10.81%
2/5/2014	3.6477	3.65%	3.65%	6/27/1983	10.80%
2/4/2014	3.601	3.60%	3.64%	6/28/1983	10.79%
2/3/2014	3.5307	3.53%	3.64%	6/29/1983	10.79%
1/31/2014	3.5985	3.60%	3.64%	6/30/1983	10.78%
1/30/2014	3.6341	3.63%	3.63%	7/1/1983	10.78%
1/29/2014	3.6163	3.62%	3.63%	7/5/1983	10.77%

1/28/2014	3.6735	3.67%	3.62%	7/6/1983	10.77%
1/27/2014	3.6649	3.66%	3.62%	7/7/1983	10.76%
1/24/2014	3.6325	3.63%	3.62%	7/8/1983	10.76%
1/23/2014	3.6821	3.68%	3.61%	7/11/1983	10.75%
1/22/2014	3.7594	3.76%	3.61%	7/12/1983	10.75%
1/21/2014	3.748	3.75%	3.60%	7/13/1983	10.75%
1/20/2014	3.748	3.75%	3.60%	7/14/1983	10.75%
1/17/2014	3.748	3.75%	3.60%	7/15/1983	10.75%
1/16/2014	3.7726	3.77%	3.59%	7/18/1983	10.74%
1/15/2014	3.823	3.82%	3.59%	7/19/1983	10.74%
1/14/2014	3.8017	3.80%	3.58%	7/20/1983	10.74%
1/13/2014	3.7726	3.77%	3.58%	7/21/1983	10.74%
1/10/2014	3.7999	3.80%	3.58%	7/22/1983	10.74%
1/9/2014	3.8795	3.88%	3.57%	7/25/1983	10.73%
1/8/2014	3.8921	3.89%	3.57%	7/26/1983	10.73%
1/7/2014	3.8849	3.88%	3.56%	7/27/1983	10.73%
1/6/2014	3.9003	3.90%	3.56%	7/28/1983	10.74%
1/3/2014	3.9248	3.92%	3.55%	7/29/1983	10.74%
1/2/2014	3.9221	3.92%	3.55%	8/1/1983	10.75%
1/1/2014	3.9679	3.97%	3.55%	8/2/1983	10.75%
12/31/2013	3.9679	3.97%	3.54%	8/4/1983	10.76%
12/30/2013	3.9012	3.90%	3.54%	8/5/1983	10.76%
12/27/2013	3.9367	3.94%	3.53%	8/8/1983	10.77%
12/26/2013	3.9239	3.92%	3.53%	8/9/1983	10.77%
12/25/2013	3.893	3.89%	3.53%	8/10/1983	10.78%
12/24/2013	3.893	3.89%	3.52%	8/11/1983	10.78%
12/23/2013	3.8489	3.85%	3.52%	8/12/1983	10.78%
12/20/2013	3.823	3.82%	3.52%	8/15/1983	10.79%
12/19/2013	3.9093	3.91%	3.51%	8/16/1983	10.79%
12/18/2013	3.9065	3.91%	3.51%	8/17/1983	10.79%
12/17/2013	3.8659	3.87%	3.51%	8/18/1983	10.79%
12/16/2013	3.8938	3.89%	3.50%	8/19/1983	10.80%
12/13/2013	3.8731	3.87%	3.50%	8/22/1983	10.80%
12/12/2013	3.8938	3.89%	3.50%	8/23/1983	10.81%
12/11/2013	3.8857	3.89%	3.49%	8/24/1983	10.81%
12/10/2013	3.8381	3.84%	3.49%	8/25/1983	10.82%
12/9/2013	3.8713	3.87%	3.48%	8/26/1983	10.82%
12/6/2013	3.8893	3.89%	3.48%	8/29/1983	10.83%
12/5/2013	3.9138	3.91%	3.48%	8/30/1983	10.84%
12/4/2013	3.9011	3.90%	3.47%	8/31/1983	10.84%
12/3/2013	3.8444	3.84%	3.47%	9/1/1983	10.85%
12/2/2013	3.856	3.86%	3.46%	9/6/1983	10.86%
11/29/2013	3.8106	3.81%	3.46%	9/7/1983	10.86%
11/28/2013	3.815	3.82%	3.46%	9/8/1983	10.87%
11/27/2013	3.815	3.82%	3.45%	9/9/1983	10.88%
11/26/2013	3.7982	3.80%	3.45%	9/12/1983	10.88%
11/25/2013	3.8186	3.82%	3.45%	9/13/1983	10.89%

11/22/2013	3.8292	3.83%	3.44%	9/14/1983	10.89%
11/21/2013	3.8875	3.89%	3.44%	9/15/1983	10.90%
11/20/2013	3.911	3.91%	3.44%	9/16/1983	10.90%
11/19/2013	3.8	3.80%	3.43%	9/19/1983	10.91%
11/18/2013	3.7552	3.76%	3.43%	9/20/1983	10.91%
11/15/2013	3.7947	3.79%	3.43%	9/21/1983	10.92%
11/14/2013	3.7867	3.79%	3.43%	9/22/1983	10.92%
11/13/2013	3.8191	3.82%	3.42%	9/23/1983	10.93%
11/12/2013	3.8573	3.86%	3.42%	9/26/1983	10.93%
11/11/2013	3.8454	3.85%	3.42%	9/27/1983	10.94%
11/8/2013	3.8454	3.85%	3.41%	9/28/1983	10.94%
11/7/2013	3.7084	3.71%	3.41%	9/29/1983	10.95%
11/6/2013	3.7732	3.77%	3.41%	9/30/1983	10.95%
11/5/2013	3.7714	3.77%	3.40%	10/3/1983	10.95%
11/4/2013	3.6926	3.69%	3.40%	10/4/1983	10.96%
11/1/2013	3.6961	3.70%	3.40%	10/5/1983	10.96%
10/31/2013	3.6386	3.64%	3.40%	10/6/1983	10.96%
10/30/2013	3.6412	3.64%	3.39%	10/7/1983	10.97%
10/29/2013	3.6127	3.61%	3.39%	10/11/1983	10.97%
10/28/2013	3.6179	3.62%	3.39%	10/12/1983	10.98%
10/25/2013	3.5999	3.60%	3.38%	10/13/1983	10.99%
10/24/2013	3.611	3.61%	3.38%	10/14/1983	10.99%
10/23/2013	3.5947	3.59%	3.38%	10/17/1983	11.00%
10/22/2013	3.6085	3.61%	3.37%	10/18/1983	11.00%
10/21/2013	3.6698	3.67%	3.37%	10/19/1983	11.01%
10/18/2013	3.6412	3.64%	3.37%	10/20/1983	11.01%
10/17/2013	3.6585	3.66%	3.37%	10/21/1983	11.02%
10/16/2013	3.7207	3.72%	3.36%	10/24/1983	11.02%
10/15/2013	3.7891	3.79%	3.36%	10/25/1983	11.03%
10/14/2013	3.7472	3.75%	3.36%	10/26/1983	11.04%
10/11/2013	3.7472	3.75%	3.35%	10/27/1983	11.04%
10/10/2013	3.7339	3.73%	3.35%	10/28/1983	11.05%
10/9/2013	3.7374	3.74%	3.35%	10/31/1983	11.05%
10/8/2013	3.6899	3.69%	3.34%	11/1/1983	11.06%
10/7/2013	3.6917	3.69%	3.34%	11/2/1983	11.07%
10/4/2013	3.7198	3.72%	3.34%	11/3/1983	11.07%
10/3/2013	3.7074	3.71%	3.33%	11/4/1983	11.08%
10/2/2013	3.7013	3.70%	3.33%	11/7/1983	11.09%
10/1/2013	3.7171	3.72%	3.32%	11/9/1983	11.09%
9/30/2013	3.6847	3.68%	3.32%	11/10/1983	11.10%
9/27/2013	3.6864	3.69%	3.32%	11/14/1983	11.10%
9/26/2013	3.6951	3.70%	3.31%	11/15/1983	11.11%
9/25/2013	3.6698	3.67%	3.31%	11/16/1983	11.11%
9/24/2013	3.6698	3.67%	3.31%	11/17/1983	11.11%
9/23/2013	3.725	3.73%	3.30%	11/18/1983	11.12%
9/20/2013	3.7613	3.76%	3.30%	11/21/1983	11.12%
9/19/2013	3.8024	3.80%	3.29%	11/22/1983	11.13%

9/18/2013	3.7471	3.75%	3.29%	11/23/1983	11.13%
9/17/2013	3.8322	3.83%	3.28%	11/25/1983	11.13%
9/16/2013	3.8667	3.87%	3.28%	11/28/1983	11.13%
9/13/2013	3.8349	3.83%	3.27%	11/29/1983	11.14%
9/12/2013	3.8521	3.85%	3.27%	11/30/1983	11.14%
9/11/2013	3.8539	3.85%	3.26%	12/1/1983	11.14%
9/10/2013	3.8941	3.89%	3.26%	12/2/1983	11.15%
9/9/2013	3.853	3.85%	3.25%	12/5/1983	11.15%
9/6/2013	3.8657	3.87%	3.25%	12/6/1983	11.15%
9/5/2013	3.8849	3.88%	3.24%	12/7/1983	11.16%
9/4/2013	3.797	3.80%	3.24%	12/8/1983	11.16%
9/3/2013	3.7943	3.79%	3.23%	12/9/1983	11.17%
9/2/2013	3.6995	3.70%	3.23%	12/12/1983	11.17%
8/30/2013	3.6995	3.70%	3.22%	12/13/1983	11.18%
8/29/2013	3.7144	3.71%	3.22%	12/14/1983	11.19%
8/28/2013	3.7356	3.74%	3.21%	12/15/1983	11.19%
8/27/2013	3.6916	3.69%	3.21%	12/16/1983	11.20%
8/26/2013	3.7648	3.76%	3.20%	12/19/1983	11.21%
8/23/2013	3.7916	3.79%	3.20%	12/20/1983	11.22%
8/22/2013	3.8702	3.87%	3.19%	12/21/1983	11.22%
8/21/2013	3.9197	3.92%	3.19%	12/22/1983	11.23%
8/20/2013	3.8529	3.85%	3.18%	12/23/1983	11.24%
8/19/2013	3.8995	3.90%	3.18%	12/27/1983	11.24%
8/16/2013	3.8483	3.85%	3.17%	12/28/1983	11.25%
8/15/2013	3.8086	3.81%	3.17%	12/29/1983	11.26%
8/14/2013	3.7523	3.75%	3.16%	12/30/1983	11.26%
8/13/2013	3.7594	3.76%	3.16%	1/3/1984	11.27%
8/12/2013	3.6838	3.68%	3.15%	1/4/1984	11.27%
8/9/2013	3.6345	3.63%	3.15%	1/5/1984	11.28%
8/8/2013	3.6729	3.67%	3.14%	1/6/1984	11.28%
8/7/2013	3.6854	3.69%	3.14%	1/9/1984	11.29%
8/6/2013	3.728	3.73%	3.14%	1/10/1984	11.30%
8/5/2013	3.726	3.73%	3.13%	1/11/1984	11.30%
8/2/2013	3.6843	3.68%	3.13%	1/12/1984	11.31%
8/1/2013	3.7542	3.75%	3.12%	1/13/1984	11.31%
7/31/2013	3.6353	3.64%	3.12%	1/16/1984	11.32%
7/30/2013	3.6821	3.68%	3.12%	1/17/1984	11.32%
7/29/2013	3.6744	3.67%	3.11%	1/18/1984	11.33%
7/26/2013	3.6209	3.62%	3.11%	1/19/1984	11.33%
7/25/2013	3.6407	3.64%	3.11%	1/20/1984	11.34%
7/24/2013	3.6464	3.65%	3.10%	1/23/1984	11.34%
7/23/2013	3.5773	3.58%	3.10%	1/24/1984	11.35%
7/22/2013	3.5501	3.55%	3.10%	1/25/1984	11.35%
7/19/2013	3.5604	3.56%	3.09%	1/26/1984	11.36%
7/18/2013	3.6262	3.63%	3.09%	1/27/1984	11.36%
7/17/2013	3.5752	3.58%	3.08%	1/30/1984	11.37%
7/16/2013	3.5855	3.59%	3.08%	1/31/1984	11.37%

7/15/2013	3.593	3.59%	3.08%	2/1/1984	11.38%
7/12/2013	3.625	3.63%	3.07%	2/2/1984	11.39%
7/11/2013	3.6297	3.63%	3.07%	2/3/1984	11.39%
7/10/2013	3.6496	3.65%	3.07%	2/6/1984	11.40%
7/9/2013	3.6477	3.65%	3.06%	2/7/1984	11.41%
7/8/2013	3.6334	3.63%	3.06%	2/8/1984	11.41%
7/5/2013	3.713	3.71%	3.06%	2/9/1984	11.42%
7/4/2013	3.4931	3.49%	3.05%	2/10/1984	11.43%
7/3/2013	3.4931	3.49%	3.05%	2/14/1984	11.44%
7/2/2013	3.4729	3.47%	3.04%	2/15/1984	11.44%
7/1/2013	3.4775	3.48%	3.04%	2/16/1984	11.45%
6/28/2013	3.4994	3.50%	3.04%	2/17/1984	11.46%
6/27/2013	3.5344	3.53%	3.04%	2/21/1984	11.47%
6/26/2013	3.5791	3.58%	3.03%	2/22/1984	11.47%
6/25/2013	3.6224	3.62%	3.03%	2/23/1984	11.48%
6/24/2013	3.5473	3.55%	3.03%	2/24/1984	11.49%
6/21/2013	3.5818	3.58%	3.02%	2/27/1984	11.50%
6/20/2013	3.5129	3.51%	3.02%	2/28/1984	11.51%
6/19/2013	3.4119	3.41%	3.02%	2/29/1984	11.52%
6/18/2013	3.3415	3.34%	3.02%	3/1/1984	11.53%
6/17/2013	3.3512	3.35%	3.01%	3/2/1984	11.54%
6/14/2013	3.3046	3.30%	3.01%	3/5/1984	11.55%
6/13/2013	3.3168	3.32%	3.01%	3/6/1984	11.56%
6/12/2013	3.3697	3.37%	3.01%	3/7/1984	11.57%
6/11/2013	3.3141	3.31%	3.00%	3/8/1984	11.57%
6/10/2013	3.3697	3.37%	3.00%	3/9/1984	11.58%
6/7/2013	3.3343	3.33%	3.00%	3/12/1984	11.59%
6/6/2013	3.2446	3.24%	2.99%	3/13/1984	11.60%
6/5/2013	3.2463	3.25%	2.99%	3/14/1984	11.61%
6/4/2013	3.3114	3.31%	2.99%	3/15/1984	11.62%
6/3/2013	3.2661	3.27%	2.98%	3/16/1984	11.63%
5/31/2013	3.2791	3.28%	2.98%	3/19/1984	11.63%
5/30/2013	3.2712	3.27%	2.98%	3/20/1984	11.64%
5/29/2013	3.266	3.27%	2.98%	3/21/1984	11.65%
5/28/2013	3.3217	3.32%	2.97%	3/22/1984	11.66%
5/27/2013	3.1721	3.17%	2.97%	3/23/1984	11.67%
5/24/2013	3.1721	3.17%	2.97%	3/26/1984	11.68%
5/23/2013	3.1906	3.19%	2.97%	3/27/1984	11.68%
5/22/2013	3.2195	3.22%	2.97%	3/28/1984	11.69%
5/21/2013	3.1309	3.13%	2.97%	3/29/1984	11.70%
5/20/2013	3.1762	3.18%	2.97%	3/30/1984	11.71%
5/17/2013	3.1669	3.17%	2.96%	4/2/1984	11.71%
5/16/2013	3.0976	3.10%	2.96%	4/3/1984	11.72%
5/15/2013	3.1559	3.16%	2.96%	4/4/1984	11.73%
5/14/2013	3.1905	3.19%	2.96%	4/5/1984	11.74%
5/13/2013	3.1308	3.13%	2.96%	4/6/1984	11.75%
5/10/2013	3.0943	3.09%	2.95%	4/9/1984	11.76%

5/9/2013	2.9926	2.99%	2.95%	4/10/1984	11.77%
5/8/2013	2.9871	2.99%	2.95%	4/11/1984	11.78%
5/7/2013	2.995	3.00%	2.95%	4/12/1984	11.78%
5/6/2013	2.9762	2.98%	2.94%	4/13/1984	11.79%
5/3/2013	2.9537	2.95%	2.94%	4/16/1984	11.80%
5/2/2013	2.8211	2.82%	2.94%	4/17/1984	11.81%
5/1/2013	2.8278	2.83%	2.94%	4/18/1984	11.82%
4/30/2013	2.8762	2.88%	2.94%	4/19/1984	11.83%
4/29/2013	2.8785	2.88%	2.94%	4/23/1984	11.83%
4/26/2013	2.8611	2.86%	2.93%	4/24/1984	11.84%
4/25/2013	2.9045	2.90%	2.93%	4/25/1984	11.85%
4/24/2013	2.8953	2.90%	2.93%	4/26/1984	11.86%
4/23/2013	2.903	2.90%	2.93%	4/27/1984	11.87%
4/22/2013	2.8778	2.88%	2.93%	4/30/1984	11.87%
4/19/2013	2.8847	2.88%	2.93%	5/1/1984	11.88%
4/18/2013	2.8597	2.86%	2.92%	5/2/1984	11.89%
4/17/2013	2.8779	2.88%	2.92%	5/3/1984	11.90%
4/16/2013	2.9092	2.91%	2.92%	5/4/1984	11.91%
4/15/2013	2.859	2.86%	2.92%	5/7/1984	11.91%
4/12/2013	2.9177	2.92%	2.92%	5/8/1984	11.92%
4/11/2013	2.9952	3.00%	2.92%	5/9/1984	11.93%
4/10/2013	3.003	3.00%	2.92%	5/10/1984	11.94%
4/9/2013	2.9377	2.94%	2.92%	5/11/1984	11.95%
4/8/2013	2.9147	2.91%	2.91%	5/14/1984	11.97%
4/5/2013	2.875	2.88%	2.91%	5/15/1984	11.97%
4/4/2013	2.9874	2.99%	2.91%	5/16/1984	11.98%
4/3/2013	3.052	3.05%	2.91%	5/17/1984	12.00%
4/2/2013	3.0999	3.10%	2.91%	5/18/1984	12.01%
4/1/2013	3.0743	3.07%	2.91%	5/21/1984	12.01%
3/29/2013	3.1023	3.10%	2.91%	5/22/1984	12.02%
3/28/2013	3.1023	3.10%	2.90%	5/23/1984	12.03%
3/27/2013	3.0879	3.09%	2.90%	5/24/1984	12.04%
3/26/2013	3.1427	3.14%	2.90%	5/25/1984	12.05%
3/25/2013	3.1484	3.15%	2.90%	5/29/1984	12.06%
3/22/2013	3.1476	3.15%	2.90%	5/30/1984	12.07%
3/21/2013	3.1322	3.13%	2.89%	5/31/1984	12.08%
3/20/2013	3.1983	3.20%	2.89%	6/1/1984	12.09%
3/19/2013	3.1281	3.13%	2.89%	6/4/1984	12.09%
3/18/2013	3.1843	3.18%	2.89%	6/5/1984	12.10%
3/15/2013	3.2115	3.21%	2.88%	6/6/1984	12.11%
3/14/2013	3.2388	3.24%	2.88%	6/7/1984	12.12%
3/13/2013	3.2181	3.22%	2.88%	6/8/1984	12.13%
3/12/2013	3.2131	3.21%	2.88%	6/11/1984	12.14%
3/11/2013	3.2596	3.26%	2.87%	6/12/1984	12.14%
3/8/2013	3.2438	3.24%	2.87%	6/13/1984	12.15%
3/7/2013	3.2032	3.20%	2.87%	6/14/1984	12.16%
3/6/2013	3.1517	3.15%	2.86%	6/15/1984	12.17%

3/5/2013	3.1064	3.11%	2.86%	6/18/1984	12.18%
3/4/2013	3.0864	3.09%	2.86%	6/19/1984	12.19%
3/1/2013	3.0506	3.05%	2.86%	6/20/1984	12.19%
2/28/2013	3.0856	3.09%	2.86%	6/21/1984	12.20%
2/27/2013	3.0992	3.10%	2.86%	6/22/1984	12.21%
2/26/2013	3.0784	3.08%	2.86%	6/25/1984	12.22%
2/25/2013	3.0617	3.06%	2.85%	6/26/1984	12.23%
2/22/2013	3.1525	3.15%	2.85%	6/27/1984	12.24%
2/21/2013	3.1671	3.17%	2.85%	6/28/1984	12.25%
2/20/2013	3.1991	3.20%	2.85%	6/29/1984	12.26%
2/19/2013	3.2098	3.21%	2.85%	7/2/1984	12.27%
2/18/2013	3.1753	3.18%	2.85%	7/3/1984	12.28%
2/15/2013	3.1753	3.18%	2.85%	7/5/1984	12.28%
2/14/2013	3.1765	3.18%	2.84%	7/6/1984	12.29%
2/13/2013	3.2338	3.23%	2.84%	7/9/1984	12.30%
2/12/2013	3.1886	3.19%	2.84%	7/10/1984	12.31%
2/11/2013	3.1704	3.17%	2.84%	7/11/1984	12.32%
2/8/2013	3.1635	3.16%	2.84%	7/12/1984	12.32%
2/7/2013	3.1703	3.17%	2.84%	7/13/1984	12.33%
2/6/2013	3.1694	3.17%	2.84%	7/16/1984	12.34%
2/5/2013	3.2083	3.21%	2.84%	7/17/1984	12.35%
2/4/2013	3.1599	3.16%	2.84%	7/18/1984	12.36%
2/1/2013	3.2178	3.22%	2.84%	7/19/1984	12.37%
1/31/2013	3.1719	3.17%	2.84%	7/20/1984	12.38%
1/30/2013	3.1822	3.18%	2.84%	7/23/1984	12.38%
1/29/2013	3.1839	3.18%	2.84%	7/24/1984	12.39%
1/28/2013	3.141	3.14%	2.84%	7/25/1984	12.40%
1/25/2013	3.1333	3.13%	2.84%	7/26/1984	12.41%
1/24/2013	3.0431	3.04%	2.84%	7/27/1984	12.41%
1/23/2013	3.0182	3.02%	2.84%	7/30/1984	12.42%
1/22/2013	3.0281	3.03%	2.84%	7/31/1984	12.43%
1/21/2013	3.0289	3.03%	2.84%	8/1/1984	12.43%
1/18/2013	3.0289	3.03%	2.84%	8/2/1984	12.44%
1/17/2013	3.0722	3.07%	2.84%	8/3/1984	12.44%
1/16/2013	3.0131	3.01%	2.84%	8/6/1984	12.45%
1/15/2013	3.0255	3.03%	2.84%	8/7/1984	12.45%
1/14/2013	3.0313	3.03%	2.84%	8/8/1984	12.46%
1/11/2013	3.0479	3.05%	2.84%	8/9/1984	12.46%
1/10/2013	3.0796	3.08%	2.85%	8/10/1984	12.47%
1/9/2013	3.0604	3.06%	2.85%	8/13/1984	12.47%
1/8/2013	3.0679	3.07%	2.85%	8/14/1984	12.48%
1/7/2013	3.1006	3.10%	2.85%	8/15/1984	12.48%
1/4/2013	3.0972	3.10%	2.85%	8/16/1984	12.48%
1/3/2013	3.1251	3.13%	2.85%	8/17/1984	12.49%
1/2/2013	3.0419	3.04%	2.85%	8/20/1984	12.49%
1/1/2013	2.9499	2.95%	2.85%	8/21/1984	12.49%
12/31/2012	2.9499	2.95%	2.86%	8/22/1984	12.50%

12/28/2012	2.8672	2.87%	2.86%	8/23/1984	12.50%
12/27/2012	2.9095	2.91%	2.86%	8/24/1984	12.50%
12/26/2012	2.9224	2.92%	2.86%	8/27/1984	12.51%
12/25/2012	2.9385	2.94%	2.86%	8/28/1984	12.51%
12/24/2012	2.9385	2.94%	2.87%	8/29/1984	12.51%
12/21/2012	2.9312	2.93%	2.87%	8/30/1984	12.52%
12/20/2012	2.9807	2.98%	2.87%	8/31/1984	12.52%
12/19/2012	2.9865	2.99%	2.87%	9/4/1984	12.53%
12/18/2012	2.9979	3.00%	2.88%	9/5/1984	12.53%
12/17/2012	2.9457	2.95%	2.88%	9/6/1984	12.53%
12/14/2012	2.864	2.86%	2.88%	9/7/1984	12.54%
12/13/2012	2.9054	2.91%	2.88%	9/10/1984	12.54%
12/12/2012	2.8894	2.89%	2.88%	9/11/1984	12.54%
12/11/2012	2.841	2.84%	2.88%	9/12/1984	12.55%
12/10/2012	2.7979	2.80%	2.88%	9/13/1984	12.55%
12/7/2012	2.8104	2.81%	2.89%	9/14/1984	12.55%
12/6/2012	2.7739	2.77%	2.89%	9/17/1984	12.56%
12/5/2012	2.777	2.78%	2.89%	9/18/1984	12.56%
12/4/2012	2.777	2.78%	2.89%	9/19/1984	12.56%
12/3/2012	2.7987	2.80%	2.89%	9/20/1984	12.56%
11/30/2012	2.8089	2.81%	2.89%	9/21/1984	12.56%
11/29/2012	2.7956	2.80%	2.89%	9/24/1984	12.57%
11/28/2012	2.7979	2.80%	2.90%	9/25/1984	12.57%
11/27/2012	2.7847	2.78%	2.90%	9/26/1984	12.57%
11/26/2012	2.8018	2.80%	2.90%	9/27/1984	12.57%
11/23/2012	2.8284	2.83%	2.90%	9/28/1984	12.57%
11/22/2012	2.8198	2.82%	2.90%	10/1/1984	12.57%
11/21/2012	2.8198	2.82%	2.91%	10/2/1984	12.57%
11/20/2012	2.8206	2.82%	2.91%	10/3/1984	12.58%
11/19/2012	2.7631	2.76%	2.91%	10/4/1984	12.58%
11/16/2012	2.7324	2.73%	2.91%	10/5/1984	12.58%
11/15/2012	2.7308	2.73%	2.91%	10/9/1984	12.58%
11/14/2012	2.727	2.73%	2.91%	10/10/1984	12.58%
11/13/2012	2.7247	2.72%	2.92%	10/11/1984	12.58%
11/12/2012	2.7408	2.74%	2.92%	10/12/1984	12.59%
11/9/2012	2.7408	2.74%	2.92%	10/15/1984	12.59%
11/8/2012	2.7507	2.75%	2.92%	10/16/1984	12.59%
11/7/2012	2.8279	2.83%	2.92%	10/17/1984	12.59%
11/6/2012	2.9203	2.92%	2.92%	10/18/1984	12.59%
11/5/2012	2.8762	2.88%	2.92%	10/19/1984	12.59%
11/2/2012	2.9066	2.91%	2.92%	10/22/1984	12.59%
11/1/2012	2.901	2.90%	2.93%	10/23/1984	12.59%
10/31/2012	2.8579	2.86%	2.93%	10/24/1984	12.58%
10/30/2012	2.8826	2.88%	2.93%	10/25/1984	12.58%
10/29/2012	2.8826	2.88%	2.93%	10/26/1984	12.58%
10/26/2012	2.9042	2.90%	2.93%	10/29/1984	12.58%
10/25/2012	2.9771	2.98%	2.93%	10/30/1984	12.58%

10/24/2012	2.9494	2.95%	2.93%	10/31/1984	12.58%
10/23/2012	2.9025	2.90%	2.93%	11/1/1984	12.58%
10/22/2012	2.9705	2.97%	2.93%	11/2/1984	12.58%
10/19/2012	2.9339	2.93%	2.93%	11/5/1984	12.58%
10/18/2012	3.0189	3.02%	2.93%	11/7/1984	12.58%
10/17/2012	3.0032	3.00%	2.93%	11/8/1984	12.58%
10/16/2012	2.9153	2.92%	2.93%	11/9/1984	12.58%
10/15/2012	2.8451	2.85%	2.93%	11/13/1984	12.58%
10/12/2012	2.8317	2.83%	2.93%	11/14/1984	12.58%
10/11/2012	2.8506	2.85%	2.93%	11/15/1984	12.58%
10/10/2012	2.8784	2.88%	2.93%	11/16/1984	12.58%
10/9/2012	2.9257	2.93%	2.94%	11/19/1984	12.58%
10/8/2012	2.9712	2.97%	2.94%	11/20/1984	12.58%
10/5/2012	2.9712	2.97%	2.93%	11/21/1984	12.58%
10/4/2012	2.8896	2.89%	2.93%	11/23/1984	12.58%
10/3/2012	2.8183	2.82%	2.93%	11/26/1984	12.57%
10/2/2012	2.816	2.82%	2.94%	11/27/1984	12.57%
10/1/2012	2.8199	2.82%	2.94%	11/28/1984	12.57%
9/28/2012	2.823	2.82%	2.94%	11/29/1984	12.57%
9/27/2012	2.8387	2.84%	2.94%	11/30/1984	12.56%
9/26/2012	2.7785	2.78%	2.94%	12/3/1984	12.56%
9/25/2012	2.845	2.85%	2.94%	12/4/1984	12.56%
9/24/2012	2.8959	2.90%	2.94%	12/5/1984	12.56%
9/21/2012	2.9434	2.94%	2.94%	12/6/1984	12.56%
9/20/2012	2.9441	2.94%	2.94%	12/7/1984	12.55%
9/19/2012	2.9604	2.96%	2.94%	12/10/1984	12.55%
9/18/2012	3.0053	3.01%	2.94%	12/11/1984	12.55%
9/17/2012	3.0359	3.04%	2.94%	12/12/1984	12.55%
9/14/2012	3.0884	3.09%	2.94%	12/13/1984	12.54%
9/13/2012	2.9311	2.93%	2.94%	12/14/1984	12.54%
9/12/2012	2.9215	2.92%	2.94%	12/17/1984	12.54%
9/11/2012	2.8529	2.85%	2.94%	12/18/1984	12.53%
9/10/2012	2.8057	2.81%	2.94%	12/19/1984	12.53%
9/7/2012	2.8245	2.82%	2.94%	12/20/1984	12.53%
9/6/2012	2.7987	2.80%	2.94%	12/21/1984	12.52%
9/5/2012	2.7071	2.71%	2.95%	12/24/1984	12.52%
9/4/2012	2.6821	2.68%	2.95%	12/26/1984	12.51%
9/3/2012	2.6723	2.67%	2.95%	12/27/1984	12.51%
8/31/2012	2.6723	2.67%	2.95%	12/28/1984	12.50%
8/30/2012	2.7446	2.74%	2.95%	12/31/1984	12.50%
8/29/2012	2.7646	2.76%	2.95%	1/2/1985	12.50%
8/28/2012	2.7469	2.75%	2.95%	1/3/1985	12.49%
8/27/2012	2.76	2.76%	2.95%	1/4/1985	12.49%
8/24/2012	2.8011	2.80%	2.95%	1/7/1985	12.48%
8/23/2012	2.7917	2.79%	2.95%	1/8/1985	12.48%
8/22/2012	2.8042	2.80%	2.96%	1/9/1985	12.47%
8/21/2012	2.8997	2.90%	2.96%	1/10/1985	12.47%

8/20/2012	2.9189	2.92%	2.96%	1/11/1985	12.46%
8/17/2012	2.9309	2.93%	2.96%	1/14/1985	12.46%
8/16/2012	2.9527	2.95%	2.96%	1/15/1985	12.46%
8/15/2012	2.9196	2.92%	2.96%	1/17/1985	12.45%
8/14/2012	2.8355	2.84%	2.96%	1/18/1985	12.45%
8/13/2012	2.7523	2.75%	2.96%	1/22/1985	12.44%
8/10/2012	2.7508	2.75%	2.96%	1/23/1985	12.43%
8/9/2012	2.7549	2.75%	2.97%	1/24/1985	12.43%
8/8/2012	2.7505	2.75%	2.97%	1/25/1985	12.42%
8/7/2012	2.7207	2.72%	2.97%	1/28/1985	12.41%
8/6/2012	2.6537	2.65%	2.97%	1/29/1985	12.40%
8/3/2012	2.6435	2.64%	2.97%	1/30/1985	12.40%
8/2/2012	2.5537	2.55%	2.98%	1/31/1985	12.39%
8/1/2012	2.5973	2.60%	2.98%	2/1/1985	12.39%
7/31/2012	2.5467	2.55%	2.98%	2/4/1985	12.38%
7/30/2012	2.5809	2.58%	2.99%	2/5/1985	12.37%
7/27/2012	2.6277	2.63%	2.99%	2/6/1985	12.37%
7/26/2012	2.5031	2.50%	2.99%	2/7/1985	12.36%
7/25/2012	2.453	2.45%	3.00%	2/8/1985	12.35%
7/24/2012	2.4537	2.45%	3.00%	2/11/1985	12.35%
7/23/2012	2.499	2.50%	3.00%	2/13/1985	12.34%
7/20/2012	2.5448	2.54%	3.01%	2/14/1985	12.33%
7/19/2012	2.6128	2.61%	3.01%	2/15/1985	12.32%
7/18/2012	2.597	2.60%	3.01%	2/19/1985	12.32%
7/17/2012	2.6035	2.60%	3.02%	2/20/1985	12.31%
7/16/2012	2.5577	2.56%	3.02%	2/28/1985	12.31%
7/13/2012	2.5727	2.57%	3.02%	3/5/1985	12.30%
7/12/2012	2.5614	2.56%	3.02%	3/6/1985	12.30%
7/11/2012	2.613	2.61%	3.03%	3/7/1985	12.29%
7/10/2012	2.6022	2.60%	3.03%	3/8/1985	12.28%
7/9/2012	2.6209	2.62%	3.03%	3/11/1985	12.28%
7/6/2012	2.6616	2.66%	3.03%	3/12/1985	12.27%
7/5/2012	2.716	2.72%	3.03%	3/13/1985	12.26%
7/4/2012	2.7428	2.74%	3.03%	3/14/1985	12.25%
7/3/2012	2.7428	2.74%	3.03%	3/18/1985	12.25%
7/2/2012	2.6962	2.70%	3.03%	3/19/1985	12.24%
6/29/2012	2.7533	2.75%	3.04%	3/20/1985	12.23%
6/28/2012	2.6757	2.68%	3.04%	3/21/1985	12.22%
6/27/2012	2.6918	2.69%	3.04%	3/22/1985	12.21%
6/26/2012	2.7	2.70%	3.04%	3/25/1985	12.20%
6/25/2012	2.6765	2.68%	3.04%	3/26/1985	12.20%
6/22/2012	2.7616	2.76%	3.04%	3/27/1985	12.19%
6/21/2012	2.6868	2.69%	3.05%	3/28/1985	12.18%
6/20/2012	2.7356	2.74%	3.05%	3/29/1985	12.17%
6/19/2012	2.7333	2.73%	3.05%	4/1/1985	12.16%
6/18/2012	2.6606	2.66%	3.06%	4/2/1985	12.15%
6/15/2012	2.684	2.68%	3.06%	4/3/1985	12.14%

6/14/2012	2.7409	2.74%	3.06%	4/4/1985	12.12%
6/13/2012	2.7083	2.71%	3.06%	4/8/1985	12.12%
6/12/2012	2.7693	2.77%	3.07%	4/9/1985	12.11%
6/11/2012	2.7083	2.71%	3.07%	4/10/1985	12.10%
6/8/2012	2.7454	2.75%	3.07%	4/11/1985	12.09%
6/7/2012	2.7402	2.74%	3.08%	4/12/1985	12.08%
6/6/2012	2.738	2.74%	3.08%	4/15/1985	12.07%
6/5/2012	2.642	2.64%	3.08%	4/16/1985	12.06%
6/4/2012	2.5652	2.57%	3.09%	4/17/1985	12.05%
6/1/2012	2.5194	2.52%	3.09%	4/18/1985	12.04%
5/31/2012	2.6421	2.64%	3.10%	4/19/1985	12.03%
5/30/2012	2.7137	2.71%	3.10%	4/22/1985	12.02%
5/29/2012	2.8473	2.85%	3.11%	4/23/1985	12.01%
5/28/2012	2.8412	2.84%	3.11%	4/24/1985	12.00%
5/25/2012	2.8412	2.84%	3.11%	4/25/1985	11.99%
5/24/2012	2.8719	2.87%	3.12%	4/26/1985	11.98%
5/23/2012	2.8155	2.82%	3.12%	4/29/1985	11.97%
5/22/2012	2.8665	2.87%	3.12%	4/30/1985	11.96%
5/21/2012	2.8094	2.81%	3.13%	5/1/1985	11.95%
5/18/2012	2.8064	2.81%	3.13%	5/2/1985	11.94%
5/17/2012	2.7869	2.79%	3.14%	5/3/1985	11.92%
5/16/2012	2.8989	2.90%	3.14%	5/6/1985	11.91%
5/15/2012	2.9168	2.92%	3.14%	5/7/1985	11.90%
5/14/2012	2.9199	2.92%	3.15%	5/8/1985	11.89%
5/11/2012	3.0103	3.01%	3.15%	5/9/1985	11.88%
5/10/2012	3.0407	3.04%	3.16%	5/10/1985	11.87%
5/9/2012	3.0249	3.02%	3.16%	5/13/1985	11.86%
5/8/2012	3.0336	3.03%	3.16%	5/14/1985	11.85%
5/7/2012	3.0598	3.06%	3.17%	5/15/1985	11.84%
5/4/2012	3.0709	3.07%	3.17%	5/16/1985	11.82%
5/3/2012	3.1184	3.12%	3.18%	5/17/1985	11.81%
5/2/2012	3.1159	3.12%	3.18%	5/20/1985	11.80%
5/1/2012	3.146	3.15%	3.19%	5/21/1985	11.79%
4/30/2012	3.1111	3.11%	3.20%	5/22/1985	11.78%
4/27/2012	3.1224	3.12%	3.20%	5/23/1985	11.77%
4/26/2012	3.1176	3.12%	3.21%	5/24/1985	11.76%
4/25/2012	3.1476	3.15%	3.21%	5/28/1985	11.75%
4/24/2012	3.1281	3.13%	3.22%	5/29/1985	11.73%
4/23/2012	3.0846	3.08%	3.22%	5/30/1985	11.72%
4/20/2012	3.124	3.12%	3.23%	5/31/1985	11.71%
4/19/2012	3.1208	3.12%	3.24%	6/3/1985	11.70%
4/18/2012	3.1265	3.13%	3.24%	6/4/1985	11.69%
4/17/2012	3.1411	3.14%	3.25%	6/5/1985	11.67%
4/16/2012	3.1305	3.13%	3.25%	6/6/1985	11.66%
4/13/2012	3.1273	3.13%	3.26%	6/7/1985	11.65%
4/12/2012	3.2116	3.21%	3.26%	6/10/1985	11.64%
4/11/2012	3.1959	3.20%	3.27%	6/12/1985	11.63%

4/10/2012	3.1281	3.13%	3.27%	6/13/1985	11.62%
4/9/2012	3.1959	3.20%	3.28%	6/14/1985	11.61%
4/6/2012	3.2157	3.22%	3.29%	6/17/1985	11.60%
4/5/2012	3.3265	3.33%	3.29%	6/18/1985	11.59%
4/4/2012	3.3572	3.36%	3.30%	6/19/1985	11.58%
4/3/2012	3.4404	3.44%	3.30%	6/20/1985	11.57%
4/2/2012	3.3281	3.33%	3.31%	6/21/1985	11.56%
3/30/2012	3.3358	3.34%	3.31%	6/24/1985	11.55%
3/29/2012	3.2731	3.27%	3.32%	6/25/1985	11.54%
3/28/2012	3.3102	3.31%	3.32%	6/26/1985	11.53%
3/27/2012	3.2975	3.30%	3.33%	6/27/1985	11.52%
3/26/2012	3.3391	3.34%	3.33%	6/28/1985	11.51%
3/23/2012	3.3051	3.31%	3.33%	7/1/1985	11.50%
3/22/2012	3.3596	3.36%	3.34%	7/2/1985	11.49%
3/21/2012	3.3837	3.38%	3.34%	7/3/1985	11.48%
3/20/2012	3.4454	3.45%	3.35%	7/5/1985	11.47%
3/19/2012	3.4779	3.48%	3.35%	7/8/1985	11.46%
3/16/2012	3.4061	3.41%	3.35%	7/9/1985	11.45%
3/15/2012	3.4148	3.41%	3.36%	7/10/1985	11.43%
3/14/2012	3.4009	3.40%	3.36%	7/11/1985	11.42%
3/13/2012	3.2663	3.27%	3.37%	7/12/1985	11.41%
3/12/2012	3.1712	3.17%	3.37%	7/15/1985	11.40%
3/9/2012	3.1778	3.18%	3.38%	7/16/1985	11.39%
3/8/2012	3.1745	3.17%	3.38%	7/17/1985	11.38%
3/7/2012	3.1233	3.12%	3.39%	7/18/1985	11.37%
3/6/2012	3.0736	3.07%	3.39%	7/19/1985	11.36%
3/5/2012	3.15	3.15%	3.40%	7/22/1985	11.36%
3/2/2012	3.1024	3.10%	3.40%	7/23/1985	11.35%
3/1/2012	3.1476	3.15%	3.41%	7/24/1985	11.34%
2/29/2012	3.0848	3.08%	3.41%	7/25/1985	11.33%
2/28/2012	3.0729	3.07%	3.42%	7/26/1985	11.33%
2/27/2012	3.0475	3.05%	3.43%	7/29/1985	11.32%
2/24/2012	3.0992	3.10%	3.43%	7/30/1985	11.31%
2/23/2012	3.1387	3.14%	3.44%	7/31/1985	11.30%
2/22/2012	3.1476	3.15%	3.44%	8/1/1985	11.30%
2/21/2012	3.209	3.21%	3.45%	8/2/1985	11.29%
2/20/2012	3.1476	3.15%	3.46%	8/5/1985	11.28%
2/17/2012	3.1476	3.15%	3.46%	8/6/1985	11.27%
2/16/2012	3.1387	3.14%	3.47%	8/7/1985	11.27%
2/15/2012	3.0897	3.09%	3.47%	8/8/1985	11.26%
2/14/2012	3.0873	3.09%	3.48%	8/9/1985	11.25%
2/13/2012	3.1202	3.12%	3.49%	8/12/1985	11.24%
2/10/2012	3.1404	3.14%	3.49%	8/13/1985	11.23%
2/9/2012	3.1803	3.18%	3.50%	8/14/1985	11.23%
2/8/2012	3.1509	3.15%	3.50%	8/15/1985	11.22%
2/7/2012	3.1435	3.14%	3.51%	8/16/1985	11.21%
2/6/2012	3.0966	3.10%	3.51%	8/19/1985	11.20%

2/3/2012	3.1192	3.12%	3.52%	8/20/1985	11.19%
2/2/2012	3.0028	3.00%	3.53%	8/21/1985	11.19%
2/1/2012	2.9919	2.99%	3.53%	8/22/1985	11.18%
1/31/2012	2.9375	2.94%	3.54%	8/23/1985	11.17%
1/30/2012	2.9989	3.00%	3.55%	8/26/1985	11.16%
1/27/2012	3.0574	3.06%	3.56%	8/27/1985	11.16%
1/26/2012	3.0902	3.09%	3.56%	8/28/1985	11.15%
1/25/2012	3.1484	3.15%	3.57%	8/29/1985	11.15%
1/24/2012	3.1492	3.15%	3.58%	8/30/1985	11.14%
1/23/2012	3.1297	3.13%	3.58%	9/3/1985	11.13%
1/20/2012	3.0998	3.10%	3.59%	9/4/1985	11.13%
1/19/2012	3.0416	3.04%	3.60%	9/5/1985	11.12%
1/18/2012	2.9562	2.96%	3.60%	9/6/1985	11.12%
1/17/2012	2.8985	2.90%	3.61%	9/9/1985	11.11%
1/16/2012	2.91	2.91%	3.62%	9/10/1985	11.11%
1/13/2012	2.91	2.91%	3.63%	9/11/1985	11.11%
1/12/2012	2.971	2.97%	3.64%	9/12/1985	11.10%
1/11/2012	2.9632	2.96%	3.65%	9/13/1985	11.09%
1/10/2012	3.0242	3.02%	3.65%	9/16/1985	11.09%
1/9/2012	3.0266	3.03%	3.66%	9/17/1985	11.08%
1/6/2012	3.0156	3.02%	3.67%	9/18/1985	11.08%
1/5/2012	3.0607	3.06%	3.68%	9/19/1985	11.07%
1/4/2012	3.0274	3.03%	3.68%	9/20/1985	11.07%
1/3/2012	2.9812	2.98%	3.69%	9/23/1985	11.06%
1/2/2012	2.8941	2.89%	3.70%	9/24/1985	11.06%
12/30/2011	2.8941	2.89%	3.71%	9/25/1985	11.05%
12/29/2011	2.9025	2.90%	3.71%	9/26/1985	11.05%
12/28/2011	2.9202	2.92%	3.72%	9/27/1985	11.05%
12/27/2011	3.0314	3.03%	3.73%	9/30/1985	11.04%
12/26/2011	3.0568	3.06%	3.74%	10/1/1985	11.04%
12/23/2011	3.0568	3.06%	3.74%	10/2/1985	11.03%
12/22/2011	2.9805	2.98%	3.75%	10/3/1985	11.03%
12/21/2011	3.0008	3.00%	3.76%	10/4/1985	11.02%
12/20/2011	2.9264	2.93%	3.76%	10/7/1985	11.02%
12/19/2011	2.7861	2.79%	3.77%	10/8/1985	11.01%
12/16/2011	2.8511	2.85%	3.78%	10/9/1985	11.01%
12/15/2011	2.9173	2.92%	3.79%	10/10/1985	11.00%
12/14/2011	2.9028	2.90%	3.80%	10/11/1985	11.00%
12/13/2011	3.0111	3.01%	3.81%	10/15/1985	10.99%
12/12/2011	3.0505	3.05%	3.81%	10/16/1985	10.99%
12/9/2011	3.1072	3.11%	3.82%	10/17/1985	10.98%
12/8/2011	2.997	3.00%	3.83%	10/18/1985	10.98%
12/7/2011	3.0617	3.06%	3.84%	10/21/1985	10.97%
12/6/2011	3.0984	3.10%	3.85%	10/22/1985	10.97%
12/5/2011	3.0277	3.03%	3.85%	10/23/1985	10.96%
12/2/2011	3.0237	3.02%	3.86%	10/24/1985	10.96%
12/1/2011	3.0912	3.09%	3.87%	10/25/1985	10.95%

11/30/2011	3.0554	3.06%	3.87%	10/28/1985	10.95%
11/29/2011	2.9567	2.96%	3.88%	10/29/1985	10.94%
11/28/2011	2.929	2.93%	3.89%	10/30/1985	10.94%
11/25/2011	2.9191	2.92%	3.90%	10/31/1985	10.93%
11/24/2011	2.8343	2.83%	3.91%	11/1/1985	10.92%
11/23/2011	2.8343	2.83%	3.92%	11/4/1985	10.92%
11/22/2011	2.8803	2.88%	3.93%	11/5/1985	10.91%
11/21/2011	2.9437	2.94%	3.94%	11/6/1985	10.90%
11/18/2011	2.9941	2.99%	3.94%	11/7/1985	10.90%
11/17/2011	2.9809	2.98%	3.95%	11/8/1985	10.89%
11/16/2011	3.0302	3.03%	3.96%	11/12/1985	10.88%
11/15/2011	3.0841	3.08%	3.97%	11/13/1985	10.87%
11/14/2011	3.1057	3.11%	3.98%	11/14/1985	10.87%
11/11/2011	3.13	3.13%	3.99%	11/15/1985	10.86%
11/10/2011	3.1063	3.11%	3.99%	11/18/1985	10.85%
11/9/2011	3.028	3.03%	4.00%	11/19/1985	10.84%
11/8/2011	3.1372	3.14%	4.01%	11/20/1985	10.84%
11/7/2011	3.0997	3.10%	4.02%	11/21/1985	10.83%
11/4/2011	3.0916	3.09%	4.02%	11/22/1985	10.82%
11/3/2011	3.1216	3.12%	4.03%	11/25/1985	10.82%
11/2/2011	3.0129	3.01%	4.04%	11/26/1985	10.81%
11/1/2011	2.9998	3.00%	4.05%	11/27/1985	10.80%
10/31/2011	3.1307	3.13%	4.05%	11/29/1985	10.80%
10/28/2011	3.3754	3.38%	4.06%	12/2/1985	10.79%
10/27/2011	3.4561	3.46%	4.07%	12/3/1985	10.79%
10/26/2011	3.2205	3.22%	4.07%	12/4/1985	10.78%
10/25/2011	3.1301	3.13%	4.08%	12/5/1985	10.77%
10/24/2011	3.2707	3.27%	4.09%	12/6/1985	10.76%
10/21/2011	3.2638	3.26%	4.09%	12/9/1985	10.76%
10/20/2011	3.216	3.22%	4.10%	12/10/1985	10.75%
10/19/2011	3.1756	3.18%	4.11%	12/11/1985	10.74%
10/18/2011	3.1718	3.17%	4.11%	12/12/1985	10.73%
10/17/2011	3.1304	3.13%	4.12%	12/13/1985	10.72%
10/14/2011	3.2315	3.23%	4.13%	12/16/1985	10.71%
10/13/2011	3.1508	3.15%	4.13%	12/17/1985	10.70%
10/12/2011	3.1964	3.20%	4.14%	12/18/1985	10.69%
10/11/2011	3.0999	3.10%	4.15%	12/19/1985	10.68%
10/10/2011	3.0167	3.02%	4.15%	12/20/1985	10.67%
10/7/2011	3.0167	3.02%	4.16%	12/23/1985	10.66%
10/6/2011	2.9496	2.95%	4.17%	12/24/1985	10.64%
10/5/2011	2.8519	2.85%	4.17%	12/26/1985	10.63%
10/4/2011	2.8039	2.80%	4.18%	12/27/1985	10.62%
10/3/2011	2.7246	2.72%	4.19%	12/30/1985	10.61%
9/30/2011	2.9134	2.91%	4.20%	12/31/1985	10.59%
9/29/2011	3.0537	3.05%	4.21%	1/2/1986	10.58%
9/28/2011	3.07	3.07%	4.21%	1/3/1986	10.57%
9/27/2011	3.0693	3.07%	4.22%	1/6/1986	10.56%

9/26/2011	2.9925	2.99%	4.23%	1/7/1986	10.54%
9/23/2011	2.9002	2.90%	4.23%	1/8/1986	10.53%
9/22/2011	2.7977	2.80%	4.24%	1/9/1986	10.52%
9/21/2011	2.9942	2.99%	4.25%	1/10/1986	10.51%
9/20/2011	3.2024	3.20%	4.26%	1/13/1986	10.50%
9/19/2011	3.2184	3.22%	4.26%	1/14/1986	10.49%
9/16/2011	3.313	3.31%	4.27%	1/15/1986	10.47%
9/15/2011	3.3565	3.36%	4.28%	1/16/1986	10.46%
9/14/2011	3.271	3.27%	4.28%	1/17/1986	10.45%
9/13/2011	3.3273	3.33%	4.29%	1/21/1986	10.44%
9/12/2011	3.2509	3.25%	4.29%	1/22/1986	10.43%
9/9/2011	3.2463	3.25%	4.30%	1/23/1986	10.42%
9/8/2011	3.3086	3.31%	4.30%	1/24/1986	10.41%
9/7/2011	3.367	3.37%	4.31%	1/27/1986	10.39%
9/6/2011	3.272	3.27%	4.31%	1/28/1986	10.38%
9/5/2011	3.2969	3.30%	4.32%	1/29/1986	10.37%
9/2/2011	3.2969	3.30%	4.32%	1/30/1986	10.36%
9/1/2011	3.4945	3.49%	4.32%	1/31/1986	10.35%
8/31/2011	3.6008	3.60%	4.33%	2/3/1986	10.34%
8/30/2011	3.5225	3.52%	4.33%	2/4/1986	10.33%
8/29/2011	3.5916	3.59%	4.34%	2/5/1986	10.32%
8/26/2011	3.535	3.54%	4.34%	2/6/1986	10.31%
8/25/2011	3.6009	3.60%	4.34%	2/7/1986	10.30%
8/24/2011	3.6534	3.65%	4.35%	2/10/1986	10.29%
8/23/2011	3.4931	3.49%	4.35%	2/11/1986	10.28%
8/22/2011	3.4233	3.42%	4.35%	2/12/1986	10.27%
8/19/2011	3.3904	3.39%	4.36%	2/13/1986	10.26%
8/18/2011	3.4193	3.42%	4.36%	2/14/1986	10.24%
8/17/2011	3.5633	3.56%	4.37%	2/18/1986	10.23%
8/16/2011	3.6671	3.67%	4.37%	2/19/1986	10.22%
8/15/2011	3.771	3.77%	4.37%	2/20/1986	10.21%
8/12/2011	3.7257	3.73%	4.37%	2/21/1986	10.19%
8/11/2011	3.769	3.77%	4.38%	2/24/1986	10.18%
8/10/2011	3.5146	3.51%	4.38%	2/25/1986	10.17%
8/9/2011	3.6181	3.62%	4.38%	2/26/1986	10.15%
8/8/2011	3.653	3.65%	4.38%	2/27/1986	10.14%
8/5/2011	3.8458	3.85%	4.38%	2/28/1986	10.12%
8/4/2011	3.6707	3.67%	4.38%	3/3/1986	10.11%
8/3/2011	3.902	3.90%	4.39%	3/4/1986	10.09%
8/2/2011	3.9088	3.91%	4.39%	3/5/1986	10.08%
8/1/2011	4.0795	4.08%	4.39%	3/6/1986	10.06%
7/29/2011	4.1184	4.12%	4.39%	3/7/1986	10.05%
7/28/2011	4.2556	4.26%	4.39%	3/10/1986	10.03%
7/27/2011	4.2851	4.29%	4.38%	3/11/1986	10.02%
7/26/2011	4.2823	4.28%	4.38%	3/12/1986	10.00%
7/25/2011	4.3194	4.32%	4.38%	3/13/1986	9.99%
7/22/2011	4.2575	4.26%	4.38%	3/14/1986	9.97%

7/21/2011	4.312	4.31%	4.38%	3/17/1986	9.96%
7/20/2011	4.252	4.25%	4.37%	3/18/1986	9.95%
7/19/2011	4.1902	4.19%	4.37%	3/19/1986	9.93%
7/18/2011	4.3083	4.31%	4.37%	3/20/1986	9.92%
7/15/2011	4.2465	4.25%	4.37%	3/21/1986	9.91%
7/14/2011	4.2539	4.25%	4.37%	3/24/1986	9.89%
7/13/2011	4.1722	4.17%	4.36%	3/25/1986	9.88%
7/12/2011	4.1677	4.17%	4.36%	3/26/1986	9.87%
7/11/2011	4.2083	4.21%	4.36%	3/27/1986	9.86%
7/8/2011	4.2824	4.28%	4.36%	3/31/1986	9.84%
7/7/2011	4.3662	4.37%	4.35%	4/1/1986	9.83%
7/6/2011	4.3625	4.36%	4.35%	4/2/1986	9.81%
7/5/2011	4.3728	4.37%	4.35%	4/3/1986	9.79%
7/4/2011	4.3908	4.39%	4.34%	4/4/1986	9.78%
7/1/2011	4.3908	4.39%	4.34%	4/7/1986	9.77%
6/30/2011	4.371	4.37%	4.34%	4/8/1986	9.75%
6/29/2011	4.3766	4.38%	4.33%	4/9/1986	9.74%
6/28/2011	4.3242	4.32%	4.33%	4/10/1986	9.72%
6/27/2011	4.2954	4.30%	4.33%	4/11/1986	9.71%
6/24/2011	4.1832	4.18%	4.32%	4/14/1986	9.69%
6/23/2011	4.168	4.17%	4.32%	4/15/1986	9.67%
6/22/2011	4.2149	4.21%	4.32%	4/16/1986	9.66%
6/21/2011	4.2185	4.22%	4.32%	4/17/1986	9.64%
6/20/2011	4.1977	4.20%	4.32%	4/18/1986	9.62%
6/17/2011	4.205	4.21%	4.32%	4/21/1986	9.61%
6/16/2011	4.1753	4.18%	4.32%	4/22/1986	9.59%
6/15/2011	4.1996	4.20%	4.31%	4/23/1986	9.57%
6/14/2011	4.2964	4.30%	4.31%	4/24/1986	9.56%
6/13/2011	4.2005	4.20%	4.31%	4/25/1986	9.55%
6/10/2011	4.1816	4.18%	4.31%	4/28/1986	9.53%
6/9/2011	4.215	4.22%	4.30%	4/29/1986	9.52%
6/8/2011	4.1853	4.19%	4.30%	4/30/1986	9.50%
6/7/2011	4.2579	4.26%	4.30%	5/1/1986	9.49%
6/6/2011	4.2579	4.26%	4.29%	5/2/1986	9.48%
6/3/2011	4.2224	4.22%	4.29%	5/5/1986	9.46%
6/2/2011	4.2442	4.24%	4.29%	5/6/1986	9.45%
6/1/2011	4.1415	4.14%	4.29%	5/7/1986	9.43%
5/31/2011	4.2242	4.22%	4.28%	5/8/1986	9.42%
5/30/2011	4.2424	4.24%	4.28%	5/9/1986	9.40%
5/27/2011	4.2424	4.24%	4.28%	5/12/1986	9.38%
5/26/2011	4.2225	4.22%	4.27%	5/13/1986	9.37%
5/25/2011	4.2819	4.28%	4.27%	5/14/1986	9.35%
5/24/2011	4.2498	4.25%	4.27%	5/15/1986	9.34%
5/23/2011	4.2663	4.27%	4.27%	5/16/1986	9.32%
5/20/2011	4.2976	4.30%	4.26%	5/19/1986	9.31%
5/19/2011	4.3032	4.30%	4.26%	5/20/1986	9.29%
5/18/2011	4.2949	4.29%	4.26%	5/21/1986	9.28%

5/17/2011	4.2271	4.23%	4.26%	5/22/1986	9.26%
5/16/2011	4.2719	4.27%	4.26%	5/23/1986	9.24%
5/13/2011	4.3078	4.31%	4.25%	5/27/1986	9.23%
5/12/2011	4.3469	4.35%	4.25%	5/28/1986	9.21%
5/11/2011	4.3032	4.30%	4.25%	5/29/1986	9.19%
5/10/2011	4.3506	4.35%	4.25%	5/30/1986	9.18%
5/9/2011	4.3085	4.31%	4.25%	6/2/1986	9.17%
5/6/2011	4.2855	4.29%	4.25%	6/3/1986	9.15%
5/5/2011	4.2556	4.26%	4.25%	6/4/1986	9.14%
5/4/2011	4.3211	4.32%	4.24%	6/5/1986	9.13%
5/3/2011	4.3507	4.35%	4.24%	6/6/1986	9.11%
5/2/2011	4.3786	4.38%	4.24%	6/9/1986	9.10%
4/29/2011	4.3968	4.40%	4.24%	6/10/1986	9.08%
4/28/2011	4.4141	4.41%	4.24%	6/11/1986	9.07%
4/27/2011	4.4526	4.45%	4.24%	6/12/1986	9.06%
4/26/2011	4.3905	4.39%	4.23%	6/13/1986	9.04%
4/25/2011	4.4554	4.46%	4.23%	6/16/1986	9.03%
4/22/2011	4.4646	4.46%	4.23%	6/17/1986	9.01%
4/21/2011	4.4739	4.47%	4.23%	6/18/1986	9.00%
4/20/2011	4.4656	4.47%	4.22%	6/19/1986	8.98%
4/19/2011	4.4316	4.43%	4.22%	6/20/1986	8.97%
4/18/2011	4.4564	4.46%	4.22%	6/23/1986	8.95%
4/15/2011	4.4684	4.47%	4.22%	6/24/1986	8.94%
4/14/2011	4.5485	4.55%	4.22%	6/25/1986	8.92%
4/13/2011	4.5429	4.54%	4.21%	6/26/1986	8.91%
4/12/2011	4.575	4.58%	4.21%	6/27/1986	8.89%
4/11/2011	4.6542	4.65%	4.21%	6/30/1986	8.87%
4/8/2011	4.6417	4.64%	4.20%	7/1/1986	8.85%
4/7/2011	4.6159	4.62%	4.20%	7/2/1986	8.84%
4/6/2011	4.5949	4.59%	4.20%	7/3/1986	8.82%
4/5/2011	4.5038	4.50%	4.19%	7/7/1986	8.80%
4/4/2011	4.476	4.48%	4.19%	7/8/1986	8.78%
4/1/2011	4.4853	4.49%	4.19%	7/9/1986	8.77%
3/31/2011	4.5076	4.51%	4.19%	7/10/1986	8.75%
3/30/2011	4.502	4.50%	4.18%	7/11/1986	8.73%
3/29/2011	4.5441	4.54%	4.18%	7/14/1986	8.71%
3/28/2011	4.4946	4.49%	4.18%	7/15/1986	8.70%
3/25/2011	4.5002	4.50%	4.18%	7/16/1986	8.68%
3/24/2011	4.4826	4.48%	4.18%	7/17/1986	8.66%
3/23/2011	4.4477	4.45%	4.17%	7/18/1986	8.65%
3/22/2011	4.4367	4.44%	4.17%	7/21/1986	8.63%
3/21/2011	4.4514	4.45%	4.17%	7/22/1986	8.61%
3/18/2011	4.4166	4.42%	4.17%	7/23/1986	8.60%
3/17/2011	4.4358	4.44%	4.17%	7/24/1986	8.58%
3/16/2011	4.3553	4.36%	4.17%	7/25/1986	8.57%
3/15/2011	4.4542	4.45%	4.17%	7/28/1986	8.55%
3/14/2011	4.5349	4.53%	4.16%	7/29/1986	8.54%

3/11/2011	4.548	4.55%	4.16%	7/30/1986	8.52%
3/10/2011	4.4986	4.50%	4.16%	7/31/1986	8.50%
3/9/2011	4.6067	4.61%	4.16%	8/1/1986	8.49%
3/8/2011	4.6632	4.66%	4.16%	8/4/1986	8.47%
3/7/2011	4.6219	4.62%	4.15%	8/5/1986	8.46%
3/4/2011	4.5963	4.60%	4.15%	8/6/1986	8.44%
3/3/2011	4.6191	4.62%	4.15%	8/7/1986	8.43%
3/2/2011	4.5661	4.57%	4.15%	8/8/1986	8.41%
3/1/2011	4.4794	4.48%	4.15%	8/11/1986	8.40%
2/28/2011	4.5007	4.50%	4.14%	8/12/1986	8.38%
2/25/2011	4.496	4.50%	4.14%	8/13/1986	8.37%
2/24/2011	4.5417	4.54%	4.14%	8/14/1986	8.35%
2/23/2011	4.5822	4.58%	4.14%	8/15/1986	8.34%
2/22/2011	4.6031	4.60%	4.14%	8/18/1986	8.32%
2/21/2011	4.6836	4.68%	4.13%	8/19/1986	8.30%
2/18/2011	4.6836	4.68%	4.13%	8/20/1986	8.29%
2/17/2011	4.6682	4.67%	4.13%	8/21/1986	8.27%
2/16/2011	4.6798	4.68%	4.13%	8/22/1986	8.26%
2/15/2011	4.6615	4.66%	4.13%	8/25/1986	8.24%
2/14/2011	4.6711	4.67%	4.13%	8/26/1986	8.23%
2/11/2011	4.6876	4.69%	4.13%	8/28/1986	8.22%
2/10/2011	4.7642	4.76%	4.12%	8/29/1986	8.20%
2/9/2011	4.711	4.71%	4.12%	9/2/1986	8.19%
2/8/2011	4.7652	4.77%	4.12%	9/3/1986	8.17%
2/7/2011	4.6965	4.70%	4.12%	9/4/1986	8.16%
2/4/2011	4.7275	4.73%	4.12%	9/5/1986	8.15%
2/3/2011	4.6645	4.66%	4.12%	9/8/1986	8.13%
2/2/2011	4.6196	4.62%	4.12%	9/9/1986	8.12%
2/1/2011	4.6165	4.62%	4.12%	9/10/1986	8.11%
1/31/2011	4.5711	4.57%	4.12%	9/11/1986	8.10%
1/28/2011	4.5282	4.53%	4.12%	9/12/1986	8.09%
1/27/2011	4.5691	4.57%	4.12%	9/15/1986	8.08%
1/26/2011	4.5861	4.59%	4.12%	9/16/1986	8.06%
1/25/2011	4.4896	4.49%	4.12%	9/17/1986	8.05%
1/24/2011	4.557	4.56%	4.12%	9/18/1986	8.04%
1/21/2011	4.565	4.57%	4.12%	9/19/1986	8.03%
1/20/2011	4.6093	4.61%	4.12%	9/22/1986	8.02%
1/19/2011	4.5271	4.53%	4.12%	9/23/1986	8.01%
1/18/2011	4.563	4.56%	4.12%	9/24/1986	8.00%
1/17/2011	4.5281	4.53%	4.12%	9/25/1986	7.99%
1/14/2011	4.5301	4.53%	4.12%	9/26/1986	7.98%
1/13/2011	4.4984	4.50%	4.12%	9/29/1986	7.97%
1/12/2011	4.531	4.53%	4.12%	9/30/1986	7.96%
1/11/2011	4.4876	4.49%	4.13%	10/1/1986	7.95%
1/10/2011	4.4611	4.46%	4.13%	10/2/1986	7.94%
1/7/2011	4.4846	4.48%	4.13%	10/3/1986	7.93%
1/6/2011	4.5112	4.51%	4.13%	10/6/1986	7.92%

1/5/2011	4.5439	4.54%	4.13%	10/7/1986	7.91%
1/4/2011	4.4106	4.41%	4.13%	10/8/1986	7.90%
1/3/2011	4.3971	4.40%	4.13%	10/9/1986	7.89%
12/31/2010	4.3341	4.33%	4.14%	10/10/1986	7.89%
12/30/2010	4.4231	4.42%	4.14%	10/14/1986	7.88%
12/29/2010	4.4309	4.43%	4.14%	10/15/1986	7.87%
12/28/2010	4.5319	4.53%	4.14%	10/16/1986	7.86%
12/27/2010	4.4019	4.40%	4.14%	10/17/1986	7.86%
12/24/2010	4.4698	4.47%	4.14%	10/20/1986	7.85%
12/23/2010	4.4698	4.47%	4.14%	10/21/1986	7.84%
12/22/2010	4.4464	4.45%	4.14%	10/22/1986	7.83%
12/21/2010	4.4183	4.42%	4.14%	10/23/1986	7.83%
12/20/2010	4.4415	4.44%	4.15%	10/24/1986	7.82%
12/17/2010	4.4367	4.44%	4.15%	10/27/1986	7.81%
12/16/2010	4.5338	4.53%	4.15%	10/28/1986	7.80%
12/15/2010	4.5947	4.59%	4.15%	10/29/1986	7.79%
12/14/2010	4.5288	4.53%	4.15%	10/30/1986	7.78%
12/13/2010	4.4076	4.41%	4.15%	10/31/1986	7.77%
12/10/2010	4.4289	4.43%	4.15%	11/3/1986	7.76%
12/9/2010	4.398	4.40%	4.15%	11/4/1986	7.76%
12/8/2010	4.4561	4.46%	4.15%	11/5/1986	7.75%
12/7/2010	4.3674	4.37%	4.15%	11/6/1986	7.74%
12/6/2010	4.2397	4.24%	4.15%	11/7/1986	7.73%
12/3/2010	4.3143	4.31%	4.16%	11/10/1986	7.72%
12/2/2010	4.2545	4.25%	4.16%	11/12/1986	7.71%
12/1/2010	4.2397	4.24%	4.16%	11/13/1986	7.70%
11/30/2010	4.1104	4.11%	4.16%	11/14/1986	7.69%
11/29/2010	4.1401	4.14%	4.16%	11/17/1986	7.68%
11/26/2010	4.2093	4.21%	4.17%	11/18/1986	7.67%
11/25/2010	4.275	4.28%	4.17%	11/19/1986	7.66%
11/24/2010	4.2797	4.28%	4.17%	11/20/1986	7.66%
11/23/2010	4.1901	4.19%	4.17%	11/21/1986	7.65%
11/22/2010	4.2048	4.20%	4.18%	11/24/1986	7.64%
11/19/2010	4.2444	4.24%	4.18%	11/25/1986	7.63%
11/18/2010	4.2807	4.28%	4.18%	11/26/1986	7.62%
11/17/2010	4.2853	4.29%	4.18%	11/28/1986	7.61%
11/16/2010	4.2648	4.26%	4.18%	12/1/1986	7.60%
11/15/2010	4.4153	4.42%	4.18%	12/2/1986	7.59%
11/12/2010	4.2844	4.28%	4.18%	12/3/1986	7.58%
11/11/2010	4.243	4.24%	4.19%	12/4/1986	7.58%
11/10/2010	4.2311	4.23%	4.19%	12/5/1986	7.57%
11/9/2010	4.2466	4.25%	4.19%	12/8/1986	7.56%
11/8/2010	4.1201	4.12%	4.19%	12/9/1986	7.55%
11/5/2010	4.1192	4.12%	4.19%	12/10/1986	7.55%
11/4/2010	4.0713	4.07%	4.20%	12/11/1986	7.54%
11/3/2010	4.0398	4.04%	4.20%	12/12/1986	7.53%
11/2/2010	3.9266	3.93%	4.20%	12/15/1986	7.53%

11/1/2010	4.0029	4.00%	4.20%	12/16/1986	7.52%
10/29/2010	3.9828	3.98%	4.21%	12/17/1986	7.52%
10/28/2010	4.049	4.05%	4.21%	12/18/1986	7.51%
10/27/2010	4.0564	4.06%	4.21%	12/19/1986	7.51%
10/26/2010	3.9946	3.99%	4.21%	12/22/1986	7.51%
10/25/2010	3.9095	3.91%	4.22%	12/23/1986	7.50%
10/22/2010	3.9293	3.93%	4.22%	12/24/1986	7.50%
10/21/2010	3.9609	3.96%	4.22%	12/26/1986	7.50%
10/20/2010	3.8899	3.89%	4.23%	12/29/1986	7.49%
10/19/2010	3.9131	3.91%	4.23%	12/30/1986	7.49%
10/18/2010	3.9537	3.95%	4.23%	12/31/1986	7.49%
10/15/2010	3.9791	3.98%	4.24%	1/2/1987	7.49%
10/14/2010	3.9149	3.91%	4.24%	1/5/1987	7.48%
10/13/2010	3.8166	3.82%	4.25%	1/6/1987	7.48%
10/12/2010	3.8192	3.82%	4.25%	1/7/1987	7.48%
10/11/2010	3.7489	3.75%	4.25%	1/8/1987	7.47%
10/8/2010	3.7489	3.75%	4.26%	1/9/1987	7.47%
10/7/2010	3.7121	3.71%	4.26%	1/12/1987	7.47%
10/6/2010	3.6747	3.67%	4.27%	1/13/1987	7.46%
10/5/2010	3.7472	3.75%	4.27%	1/14/1987	7.46%
10/4/2010	3.7061	3.71%	4.28%	1/15/1987	7.46%
10/1/2010	3.7147	3.71%	4.28%	1/16/1987	7.46%
9/30/2010	3.6849	3.68%	4.29%	1/20/1987	7.46%
9/29/2010	3.6841	3.68%	4.29%	1/21/1987	7.46%
9/28/2010	3.6579	3.66%	4.30%	1/22/1987	7.46%
9/27/2010	3.7181	3.72%	4.30%	1/23/1987	7.46%
9/24/2010	3.794	3.79%	4.30%	1/26/1987	7.46%
9/23/2010	3.7301	3.73%	4.31%	1/27/1987	7.46%
9/22/2010	3.7499	3.75%	4.31%	1/28/1987	7.46%
9/21/2010	3.7845	3.78%	4.32%	1/29/1987	7.46%
9/20/2010	3.8757	3.88%	4.32%	1/30/1987	7.46%
9/17/2010	3.9033	3.90%	4.32%	2/2/1987	7.46%
9/16/2010	3.9248	3.92%	4.33%	2/3/1987	7.46%
9/15/2010	3.8713	3.87%	4.33%	2/4/1987	7.46%
9/14/2010	3.7993	3.80%	4.33%	2/5/1987	7.47%
9/13/2010	3.8483	3.85%	4.33%	2/6/1987	7.47%
9/10/2010	3.8687	3.87%	4.34%	2/9/1987	7.47%
9/9/2010	3.8387	3.84%	4.34%	2/10/1987	7.47%
9/8/2010	3.7294	3.73%	4.34%	2/11/1987	7.47%
9/7/2010	3.6616	3.66%	4.34%	2/12/1987	7.47%
9/6/2010	3.7837	3.78%	4.35%	2/13/1987	7.47%
9/3/2010	3.7811	3.78%	4.35%	2/17/1987	7.47%
9/2/2010	3.7141	3.71%	4.35%	2/18/1987	7.47%
9/1/2010	3.6457	3.65%	4.35%	2/19/1987	7.47%
8/31/2010	3.5155	3.52%	4.36%	2/20/1987	7.47%
8/30/2010	3.5809	3.58%	4.36%	2/23/1987	7.47%
8/27/2010	3.6896	3.69%	4.36%	2/24/1987	7.47%

8/26/2010	3.5115	3.51%	4.37%	2/25/1987	7.47%
8/25/2010	3.5695	3.57%	4.37%	2/26/1987	7.47%
8/24/2010	3.5605	3.56%	4.37%	2/27/1987	7.47%
8/23/2010	3.6618	3.66%	4.38%	3/2/1987	7.47%
8/20/2010	3.6601	3.66%	4.38%	3/3/1987	7.47%
8/19/2010	3.6543	3.65%	4.38%	3/4/1987	7.47%
8/18/2010	3.7331	3.73%	4.39%	3/5/1987	7.47%
8/17/2010	3.7632	3.76%	4.39%	3/6/1987	7.47%
8/16/2010	3.711	3.71%	4.39%	3/9/1987	7.47%
8/13/2010	3.8538	3.85%	4.40%	3/10/1987	7.47%
8/12/2010	3.9476	3.95%	4.40%	3/11/1987	7.47%
8/11/2010	3.9188	3.92%	4.40%	3/12/1987	7.47%
8/10/2010	4.0044	4.00%	4.41%	3/13/1987	7.47%
8/9/2010	4.0165	4.02%	4.41%	3/16/1987	7.47%
8/6/2010	3.994	3.99%	4.41%	3/17/1987	7.47%
8/5/2010	4.0505	4.05%	4.41%	3/18/1987	7.47%
8/4/2010	4.0795	4.08%	4.41%	3/19/1987	7.47%
8/3/2010	4.0488	4.05%	4.41%	3/20/1987	7.47%
8/2/2010	4.0619	4.06%	4.41%	3/23/1987	7.47%
7/30/2010	3.9881	3.99%	4.41%	3/24/1987	7.47%
7/29/2010	4.0778	4.08%	4.42%	3/25/1987	7.47%
7/28/2010	4.0638	4.06%	4.42%	3/26/1987	7.46%
7/27/2010	4.0787	4.08%	4.42%	3/27/1987	7.46%
7/26/2010	4.0185	4.02%	4.42%	3/30/1987	7.46%
7/23/2010	4.0142	4.01%	4.42%	3/31/1987	7.46%
7/22/2010	3.9498	3.95%	4.42%	4/1/1987	7.47%
7/21/2010	3.8889	3.89%	4.42%	4/2/1987	7.47%
7/20/2010	3.9789	3.98%	4.42%	4/3/1987	7.47%
7/19/2010	3.9772	3.98%	4.42%	4/6/1987	7.47%
7/16/2010	3.9379	3.94%	4.43%	4/7/1987	7.47%
7/15/2010	3.9859	3.99%	4.43%	4/8/1987	7.48%
7/14/2010	4.0282	4.03%	4.43%	4/9/1987	7.48%
7/13/2010	4.1063	4.11%	4.43%	4/10/1987	7.48%
7/12/2010	4.0561	4.06%	4.43%	4/13/1987	7.49%
7/9/2010	4.0361	4.04%	4.43%	4/14/1987	7.49%
7/8/2010	4.0119	4.01%	4.43%	4/15/1987	7.50%
7/7/2010	3.9569	3.96%	4.43%	4/16/1987	7.50%
7/6/2010	3.89	3.89%	4.43%	4/20/1987	7.51%
7/5/2010	3.9425	3.94%	4.43%	4/21/1987	7.51%
7/2/2010	3.9425	3.94%	4.43%	4/22/1987	7.52%
7/1/2010	3.8944	3.89%	4.43%	4/23/1987	7.52%
6/30/2010	3.8885	3.89%	4.43%	4/24/1987	7.53%
6/29/2010	3.9316	3.93%	4.43%	4/27/1987	7.54%
6/28/2010	4.0009	4.00%	4.43%	4/28/1987	7.55%
6/25/2010	4.0625	4.06%	4.43%	4/29/1987	7.55%
6/24/2010	4.1039	4.10%	4.44%	4/30/1987	7.56%
6/23/2010	4.06	4.06%	4.44%	5/1/1987	7.57%

6/22/2010	4.1004	4.10%	4.44%	5/4/1987	7.57%
6/21/2010	4.1626	4.16%	4.44%	5/5/1987	7.58%
6/18/2010	4.1439	4.14%	4.44%	5/6/1987	7.59%
6/17/2010	4.1217	4.12%	4.44%	5/7/1987	7.60%
6/16/2010	4.1816	4.18%	4.44%	5/8/1987	7.60%
6/15/2010	4.2195	4.22%	4.44%	5/11/1987	7.61%
6/14/2010	4.1789	4.18%	4.44%	5/12/1987	7.62%
6/11/2010	4.1493	4.15%	4.44%	5/13/1987	7.63%
6/10/2010	4.2332	4.23%	4.44%	5/14/1987	7.63%
6/9/2010	4.1103	4.11%	4.44%	5/15/1987	7.64%
6/8/2010	4.1103	4.11%	4.44%	5/18/1987	7.65%
6/7/2010	4.0813	4.08%	4.44%	5/19/1987	7.66%
6/4/2010	4.1299	4.13%	4.44%	5/20/1987	7.66%
6/3/2010	4.2698	4.27%	4.44%	5/21/1987	7.67%
6/2/2010	4.2388	4.24%	4.44%	5/22/1987	7.68%
6/1/2010	4.179	4.18%	4.44%	5/26/1987	7.69%
5/31/2010	4.2043	4.20%	4.44%	5/27/1987	7.69%
5/28/2010	4.2088	4.21%	4.44%	5/28/1987	7.70%
5/27/2010	4.2553	4.26%	4.44%	5/29/1987	7.70%
5/26/2010	4.0921	4.09%	4.44%	6/1/1987	7.71%
5/25/2010	4.057	4.06%	4.44%	6/2/1987	7.72%
5/24/2010	4.0842	4.08%	4.44%	6/3/1987	7.72%
5/21/2010	4.0991	4.10%	4.45%	6/4/1987	7.73%
5/20/2010	4.0878	4.09%	4.45%	6/5/1987	7.74%
5/19/2010	4.2435	4.24%	4.45%	6/8/1987	7.74%
5/18/2010	4.2289	4.23%	4.45%	6/9/1987	7.75%
5/17/2010	4.359	4.36%	4.45%	6/10/1987	7.76%
5/14/2010	4.3357	4.34%	4.45%	6/11/1987	7.77%
5/13/2010	4.4271	4.43%	4.45%	6/12/1987	7.77%
5/12/2010	4.4803	4.48%	4.45%	6/15/1987	7.78%
5/11/2010	4.4197	4.42%	4.46%	6/16/1987	7.79%
5/10/2010	4.4104	4.41%	4.46%	6/17/1987	7.79%
5/7/2010	4.2749	4.27%	4.46%	6/18/1987	7.80%
5/6/2010	4.2003	4.20%	4.46%	6/19/1987	7.80%
5/5/2010	4.3847	4.38%	4.46%	6/22/1987	7.81%
5/4/2010	4.4123	4.41%	4.46%	6/23/1987	7.81%
5/3/2010	4.5266	4.53%	4.46%	6/24/1987	7.82%
4/30/2010	4.5172	4.52%	4.46%	6/25/1987	7.82%
4/29/2010	4.5888	4.59%	4.46%	6/26/1987	7.83%
4/28/2010	4.6265	4.63%	4.46%	6/29/1987	7.83%
4/27/2010	4.5763	4.58%	4.46%	6/30/1987	7.84%
4/26/2010	4.6646	4.66%	4.46%	7/1/1987	7.84%
4/23/2010	4.6597	4.66%	4.46%	7/2/1987	7.85%
4/22/2010	4.6363	4.64%	4.45%	7/6/1987	7.85%
4/21/2010	4.6159	4.62%	4.45%	7/7/1987	7.85%
4/20/2010	4.6734	4.67%	4.45%	7/8/1987	7.86%
4/19/2010	4.6941	4.69%	4.45%	7/9/1987	7.86%

4/16/2010	4.6705	4.67%	4.45%	7/10/1987	7.86%
4/15/2010	4.7149	4.71%	4.45%	7/13/1987	7.87%
4/14/2010	4.7298	4.73%	4.45%	7/14/1987	7.87%
4/13/2010	4.6813	4.68%	4.44%	7/15/1987	7.88%
4/12/2010	4.6961	4.70%	4.44%	7/16/1987	7.88%
4/9/2010	4.7397	4.74%	4.44%	7/17/1987	7.89%
4/8/2010	4.7527	4.75%	4.44%	7/20/1987	7.89%
4/7/2010	4.7377	4.74%	4.43%	7/21/1987	7.90%
4/6/2010	4.8324	4.83%	4.43%	7/22/1987	7.90%
4/5/2010	4.8395	4.84%	4.43%	7/23/1987	7.91%
4/2/2010	4.806	4.81%	4.43%	7/24/1987	7.92%
4/1/2010	4.7278	4.73%	4.42%	7/27/1987	7.92%
3/31/2010	4.7129	4.71%	4.42%	7/28/1987	7.93%
3/30/2010	4.7457	4.75%	4.42%	7/29/1987	7.93%
3/29/2010	4.7677	4.77%	4.42%	7/30/1987	7.94%
3/26/2010	4.7457	4.75%	4.42%	7/31/1987	7.95%
3/25/2010	4.7577	4.76%	4.42%	8/3/1987	7.95%
3/24/2010	4.7318	4.73%	4.42%	8/4/1987	7.96%
3/23/2010	4.6054	4.61%	4.41%	8/5/1987	7.96%
3/22/2010	4.5679	4.57%	4.41%	8/6/1987	7.97%
3/19/2010	4.5794	4.58%	4.41%	8/7/1987	7.98%
3/18/2010	4.591	4.59%	4.41%	8/10/1987	7.98%
3/17/2010	4.566	4.57%	4.41%	8/11/1987	7.99%
3/16/2010	4.5871	4.59%	4.42%	8/12/1987	7.99%
3/15/2010	4.6267	4.63%	4.42%	8/13/1987	8.00%
3/12/2010	4.6248	4.62%	4.42%	8/14/1987	8.00%
3/11/2010	4.6667	4.67%	4.42%	8/17/1987	8.01%
3/10/2010	4.6912	4.69%	4.42%	8/18/1987	8.01%
3/9/2010	4.6755	4.68%	4.41%	8/19/1987	8.02%
3/8/2010	4.6863	4.69%	4.41%	8/20/1987	8.03%
3/5/2010	4.6423	4.64%	4.41%	8/21/1987	8.03%
3/4/2010	4.5556	4.56%	4.41%	8/24/1987	8.04%
3/3/2010	4.5853	4.59%	4.41%	8/25/1987	8.05%
3/2/2010	4.5671	4.57%	4.41%	8/26/1987	8.06%
3/1/2010	4.5576	4.56%	4.41%	8/27/1987	8.06%
2/26/2010	4.5566	4.56%	4.41%	8/28/1987	8.07%
2/25/2010	4.5748	4.57%	4.41%	8/31/1987	8.08%
2/24/2010	4.6356	4.64%	4.41%	9/1/1987	8.09%
2/23/2010	4.6298	4.63%	4.41%	9/2/1987	8.10%
2/22/2010	4.7269	4.73%	4.40%	9/3/1987	8.11%
2/19/2010	4.7031	4.70%	4.40%	9/4/1987	8.12%
2/18/2010	4.7309	4.73%	4.40%	9/8/1987	8.13%
2/17/2010	4.6972	4.70%	4.39%	9/9/1987	8.14%
2/16/2010	4.6318	4.63%	4.39%	9/10/1987	8.15%
2/15/2010	4.6493	4.65%	4.39%	9/11/1987	8.16%
2/12/2010	4.6463	4.65%	4.39%	9/14/1987	8.17%
2/11/2010	4.6646	4.66%	4.38%	9/15/1987	8.18%

2/10/2010	4.6364	4.64%	4.38%	9/16/1987	8.19%
2/9/2010	4.5835	4.58%	4.38%	9/17/1987	8.20%
2/8/2010	4.4972	4.50%	4.38%	9/18/1987	8.21%
2/5/2010	4.5186	4.52%	4.38%	9/21/1987	8.23%
2/4/2010	4.5499	4.55%	4.37%	9/22/1987	8.24%
2/3/2010	4.6383	4.64%	4.37%	9/23/1987	8.25%
2/2/2010	4.5588	4.56%	4.37%	9/24/1987	8.26%
2/1/2010	4.5617	4.56%	4.36%	9/25/1987	8.27%
1/29/2010	4.4884	4.49%	4.36%	9/28/1987	8.28%
1/28/2010	4.5489	4.55%	4.36%	9/29/1987	8.29%
1/27/2010	4.5627	4.56%	4.35%	9/30/1987	8.31%
1/26/2010	4.5528	4.55%	4.35%	10/1/1987	8.32%
1/25/2010	4.5469	4.55%	4.35%	10/2/1987	8.33%
1/22/2010	4.5312	4.53%	4.34%	10/5/1987	8.34%
1/21/2010	4.4932	4.49%	4.34%	10/6/1987	8.35%
1/20/2010	4.5342	4.53%	4.33%	10/7/1987	8.37%
1/19/2010	4.5873	4.59%	4.33%	10/8/1987	8.38%
1/18/2010	4.5814	4.58%	4.33%	10/9/1987	8.39%
1/15/2010	4.5814	4.58%	4.32%	10/13/1987	8.40%
1/14/2010	4.6271	4.63%	4.32%	10/14/1987	8.42%
1/13/2010	4.712	4.71%	4.31%	10/15/1987	8.43%
1/12/2010	4.6171	4.62%	4.31%	10/16/1987	8.45%
1/11/2010	4.7314	4.73%	4.30%	10/19/1987	8.46%
1/8/2010	4.715	4.72%	4.30%	10/20/1987	8.47%
1/7/2010	4.6855	4.69%	4.29%	10/21/1987	8.48%
1/6/2010	4.6875	4.69%	4.29%	10/22/1987	8.49%
1/5/2010	4.6091	4.61%	4.28%	10/23/1987	8.50%
1/4/2010	4.6431	4.64%	4.28%	10/26/1987	8.50%
1/1/2010	4.6281	4.63%	4.27%	10/27/1987	8.51%
12/31/2009	4.6411	4.64%	4.27%	10/28/1987	8.52%
12/30/2009	4.6091	4.61%	4.26%	10/29/1987	8.53%
12/29/2009	4.637	4.64%	4.26%	10/30/1987	8.54%
12/28/2009	4.6894	4.69%	4.25%	11/2/1987	8.55%
12/25/2009	4.6834	4.68%	4.25%	11/3/1987	8.56%
12/24/2009	4.6833	4.68%	4.24%	11/4/1987	8.56%
12/23/2009	4.607	4.61%	4.24%	11/5/1987	8.57%
12/22/2009	4.61	4.61%	4.23%	11/6/1987	8.58%
12/21/2009	4.5586	4.56%	4.23%	11/9/1987	8.59%
12/18/2009	4.4575	4.46%	4.22%	11/10/1987	8.59%
12/17/2009	4.4164	4.42%	4.22%	11/12/1987	8.60%
12/16/2009	4.5243	4.52%	4.21%	11/13/1987	8.61%
12/15/2009	4.5214	4.52%	4.21%	11/16/1987	8.61%
12/14/2009	4.4816	4.48%	4.21%	11/17/1987	8.62%
12/11/2009	4.5009	4.50%	4.20%	11/18/1987	8.63%
12/10/2009	4.5058	4.51%	4.20%	11/19/1987	8.64%
12/9/2009	4.4184	4.42%	4.19%	11/20/1987	8.64%
12/8/2009	4.3739	4.37%	4.19%	11/23/1987	8.65%

12/7/2009	4.3843	4.38%	4.18%	11/24/1987	8.66%
12/4/2009	4.3947	4.39%	4.18%	11/25/1987	8.67%
12/3/2009	4.3318	4.33%	4.18%	11/27/1987	8.67%
12/2/2009	4.2515	4.25%	4.17%	11/30/1987	8.68%
12/1/2009	4.2735	4.27%	4.17%	12/1/1987	8.69%
11/30/2009	4.1917	4.19%	4.17%	12/2/1987	8.70%
11/27/2009	4.1998	4.20%	4.16%	12/3/1987	8.70%
11/26/2009	4.2352	4.24%	4.16%	12/4/1987	8.71%
11/25/2009	4.2334	4.23%	4.16%	12/7/1987	8.72%
11/24/2009	4.2462	4.25%	4.15%	12/8/1987	8.73%
11/23/2009	4.2764	4.28%	4.15%	12/9/1987	8.74%
11/20/2009	4.2948	4.29%	4.15%	12/10/1987	8.75%
11/19/2009	4.2774	4.28%	4.14%	12/11/1987	8.76%
11/18/2009	4.2976	4.30%	4.14%	12/14/1987	8.76%
11/17/2009	4.2572	4.26%	4.14%	12/15/1987	8.77%
11/16/2009	4.2737	4.27%	4.13%	12/16/1987	8.78%
11/13/2009	4.3516	4.35%	4.13%	12/17/1987	8.79%
11/12/2009	4.3909	4.39%	4.13%	12/18/1987	8.80%
11/11/2009	4.4124	4.41%	4.12%	12/21/1987	8.81%
11/10/2009	4.4124	4.41%	4.12%	12/22/1987	8.81%
11/9/2009	4.3993	4.40%	4.11%	12/23/1987	8.82%
11/6/2009	4.3974	4.40%	4.11%	12/24/1987	8.83%
11/5/2009	4.3984	4.40%	4.11%	12/28/1987	8.83%
11/4/2009	4.3993	4.40%	4.10%	12/29/1987	8.84%
11/3/2009	4.3288	4.33%	4.10%	12/30/1987	8.85%
11/2/2009	4.2604	4.26%	4.09%	12/31/1987	8.86%
10/30/2009	4.2253	4.23%	4.09%	1/4/1988	8.86%
10/29/2009	4.3353	4.34%	4.08%	1/5/1988	8.87%
10/28/2009	4.2587	4.26%	4.08%	1/6/1988	8.88%
10/27/2009	4.2759	4.28%	4.07%	1/7/1988	8.88%
10/26/2009	4.3649	4.36%	4.06%	1/8/1988	8.89%
10/23/2009	4.2923	4.29%	4.06%	1/11/1988	8.90%
10/22/2009	4.2362	4.24%	4.05%	1/12/1988	8.91%
10/21/2009	4.2075	4.21%	4.04%	1/13/1988	8.91%
10/20/2009	4.1657	4.17%	4.04%	1/14/1988	8.92%
10/19/2009	4.1995	4.20%	4.03%	1/15/1988	8.93%
10/16/2009	4.2443	4.24%	4.02%	1/19/1988	8.93%
10/15/2009	4.3024	4.30%	4.02%	1/20/1988	8.94%
10/14/2009	4.2634	4.26%	4.01%	1/21/1988	8.94%
10/13/2009	4.1996	4.20%	4.01%	1/22/1988	8.94%
10/12/2009	4.2282	4.23%	4.00%	1/25/1988	8.95%
10/9/2009	4.2229	4.22%	3.99%	1/26/1988	8.95%
10/8/2009	4.088	4.09%	3.99%	1/27/1988	8.95%
10/7/2009	4.0021	4.00%	3.98%	1/28/1988	8.96%
10/6/2009	4.0664	4.07%	3.97%	1/29/1988	8.96%
10/5/2009	4.0158	4.02%	3.97%	2/1/1988	8.96%
10/2/2009	3.9962	4.00%	3.96%	2/2/1988	8.96%

10/1/2009	3.9557	3.96%	3.95%	2/3/1988	8.96%
9/30/2009	4.0501	4.05%	3.95%	2/4/1988	8.96%
9/29/2009	4.0176	4.02%	3.94%	2/5/1988	8.96%
9/28/2009	4.0322	4.03%	3.93%	2/8/1988	8.96%
9/25/2009	4.09	4.09%	3.92%	2/9/1988	8.96%
9/24/2009	4.1724	4.17%	3.92%	2/10/1988	8.96%
9/23/2009	4.1973	4.20%	3.91%	2/11/1988	8.96%
9/22/2009	4.1964	4.20%	3.90%	2/12/1988	8.95%
9/21/2009	4.2348	4.23%	3.89%	2/16/1988	8.95%
9/18/2009	4.2169	4.22%	3.89%	2/17/1988	8.95%
9/17/2009	4.1655	4.17%	3.88%	2/18/1988	8.95%
9/16/2009	4.2574	4.26%	3.88%	2/19/1988	8.95%
9/15/2009	4.2656	4.27%	3.87%	2/22/1988	8.95%
9/14/2009	4.2287	4.23%	3.86%	2/23/1988	8.95%
9/11/2009	4.1797	4.18%	3.86%	2/24/1988	8.95%
9/10/2009	4.1984	4.20%	3.85%	2/25/1988	8.95%
9/9/2009	4.3285	4.33%	3.85%	2/26/1988	8.95%
9/8/2009	4.3184	4.32%	3.84%	2/29/1988	8.94%
9/7/2009	4.2693	4.27%	3.84%	3/1/1988	8.94%
9/4/2009	4.2666	4.27%	3.83%	3/2/1988	8.94%
9/3/2009	4.1604	4.16%	3.83%	3/3/1988	8.94%
9/2/2009	4.1201	4.12%	3.82%	3/4/1988	8.94%
9/1/2009	4.1923	4.19%	3.82%	3/7/1988	8.93%
8/31/2009	4.1782	4.18%	3.82%	3/8/1988	8.93%
8/28/2009	4.2004	4.20%	3.82%	3/9/1988	8.93%
8/27/2009	4.2236	4.22%	3.81%	3/10/1988	8.93%
8/26/2009	4.1951	4.20%	3.81%	3/11/1988	8.92%
8/25/2009	4.2228	4.22%	3.81%	3/14/1988	8.92%
8/24/2009	4.2659	4.27%	3.81%	3/15/1988	8.92%
8/21/2009	4.3748	4.37%	3.81%	3/16/1988	8.92%
8/20/2009	4.2426	4.24%	3.81%	3/17/1988	8.92%
8/19/2009	4.2914	4.29%	3.81%	3/18/1988	8.92%
8/18/2009	4.3527	4.35%	3.81%	3/21/1988	8.92%
8/17/2009	4.3242	4.32%	3.81%	3/22/1988	8.92%
8/14/2009	4.4206	4.42%	3.80%	3/23/1988	8.92%
8/13/2009	4.4273	4.43%	3.80%	3/24/1988	8.92%
8/12/2009	4.5373	4.54%	3.80%	3/25/1988	8.92%
8/11/2009	4.436	4.44%	3.80%	3/28/1988	8.92%
8/10/2009	4.5313	4.53%	3.80%	3/29/1988	8.92%
8/7/2009	4.6045	4.60%	3.80%	3/30/1988	8.92%
8/6/2009	4.5333	4.53%	3.80%	3/31/1988	8.92%
8/5/2009	4.5492	4.55%	3.80%	4/4/1988	8.92%
8/4/2009	4.4632	4.46%	3.79%	4/5/1988	8.93%
8/3/2009	4.404	4.40%	3.79%	4/6/1988	8.93%
7/31/2009	4.2983	4.30%	3.79%	4/7/1988	8.93%
7/30/2009	4.4107	4.41%	3.79%	4/8/1988	8.93%
7/29/2009	4.5074	4.51%	3.79%	4/11/1988	8.93%

7/28/2009	4.5491	4.55%	3.79%	4/12/1988	8.93%
7/27/2009	4.6256	4.63%	3.78%	4/13/1988	8.94%
7/24/2009	4.5391	4.54%	3.78%	4/14/1988	8.94%
7/23/2009	4.55	4.55%	3.78%	4/15/1988	8.94%
7/22/2009	4.4465	4.45%	3.78%	4/18/1988	8.94%
7/21/2009	4.3905	4.39%	3.78%	4/19/1988	8.95%
7/20/2009	4.5142	4.51%	3.78%	4/20/1988	8.95%
7/17/2009	4.535	4.54%	3.78%	4/21/1988	8.95%
7/16/2009	4.4475	4.45%	3.77%	4/22/1988	8.95%
7/15/2009	4.4886	4.49%	3.77%	4/25/1988	8.96%
7/14/2009	4.3741	4.37%	3.77%	4/26/1988	8.96%
7/13/2009	4.2321	4.23%	3.77%	4/27/1988	8.96%
7/10/2009	4.1989	4.20%	3.77%	4/28/1988	8.97%
7/9/2009	4.3002	4.30%	3.77%	4/29/1988	8.97%
7/8/2009	4.1935	4.19%	3.77%	5/2/1988	8.97%
7/7/2009	4.3086	4.31%	3.77%	5/3/1988	8.97%
7/6/2009	4.3579	4.36%	3.77%	5/4/1988	8.98%
7/3/2009	4.3209	4.32%	3.77%	5/5/1988	8.98%
7/2/2009	4.3181	4.32%	3.77%	5/6/1988	8.98%
7/1/2009	4.3285	4.33%	3.77%	5/9/1988	8.98%
6/30/2009	4.3294	4.33%	3.77%	5/10/1988	8.99%
6/29/2009	4.287	4.29%	3.77%	5/11/1988	8.99%
6/26/2009	4.336	4.34%	3.77%	5/12/1988	8.99%
6/25/2009	4.3341	4.33%	3.77%	5/13/1988	8.99%
6/24/2009	4.427	4.43%	3.77%	5/16/1988	8.99%
6/23/2009	4.3569	4.36%	3.77%	5/17/1988	8.99%
6/22/2009	4.4376	4.44%	3.76%	5/18/1988	9.00%
6/19/2009	4.5041	4.50%	3.76%	5/19/1988	9.00%
6/18/2009	4.6038	4.60%	3.76%	5/20/1988	9.00%
6/17/2009	4.51	4.51%	3.76%	5/23/1988	9.00%
6/16/2009	4.4727	4.47%	3.76%	5/24/1988	9.00%
6/15/2009	4.5606	4.56%	3.76%	5/25/1988	9.01%
6/12/2009	4.6443	4.64%	3.75%	5/26/1988	9.01%
6/11/2009	4.6965	4.70%	3.75%	5/27/1988	9.01%
6/10/2009	4.762	4.76%	3.75%	5/31/1988	9.01%
6/9/2009	4.6524	4.65%	3.75%	6/2/1988	9.01%
6/8/2009	4.6138	4.61%	3.75%	6/3/1988	9.01%
6/5/2009	4.6331	4.63%	3.75%	6/6/1988	9.02%
6/4/2009	4.5785	4.58%	3.74%	6/7/1988	9.02%
6/3/2009	4.4453	4.45%	3.74%	6/8/1988	9.02%
6/2/2009	4.4824	4.48%	3.74%	6/9/1988	9.02%
6/1/2009	4.5337	4.53%	3.74%	6/10/1988	9.02%
5/29/2009	4.3361	4.34%	3.74%	6/13/1988	9.02%
5/28/2009	4.4873	4.49%	3.74%	6/14/1988	9.02%
5/27/2009	4.6319	4.63%	3.74%	6/15/1988	9.02%
5/26/2009	4.4912	4.49%	3.74%	6/16/1988	9.02%
5/25/2009	4.3836	4.38%	3.74%	6/17/1988	9.02%

5/22/2009	4.3836	4.38%	3.74%	6/20/1988	9.02%
5/21/2009	4.3125	4.31%	3.74%	6/21/1988	9.02%
5/20/2009	4.1438	4.14%	3.74%	6/22/1988	9.02%
5/19/2009	4.2085	4.21%	3.75%	6/23/1988	9.01%
5/18/2009	4.1984	4.20%	3.75%	6/24/1988	9.01%
5/15/2009	4.0838	4.08%	3.75%	6/27/1988	9.01%
5/14/2009	4.0483	4.05%	3.75%	6/28/1988	9.00%
5/13/2009	4.099	4.10%	3.75%	6/29/1988	9.00%
5/12/2009	4.1593	4.16%	3.76%	6/30/1988	9.00%
5/11/2009	4.1847	4.18%	3.76%	7/1/1988	8.99%
5/8/2009	4.2676	4.27%	3.76%	7/5/1988	8.99%
5/7/2009	4.3057	4.31%	3.76%	7/6/1988	8.99%
5/6/2009	4.0949	4.09%	3.76%	7/7/1988	8.98%
5/5/2009	4.0655	4.07%	3.77%	7/8/1988	8.98%
5/4/2009	4.048	4.05%	3.77%	7/11/1988	8.98%
5/1/2009	4.0703	4.07%	3.77%	7/12/1988	8.98%
4/30/2009	4.0324	4.03%	3.78%	7/13/1988	8.97%
4/29/2009	4.0275	4.03%	3.78%	7/14/1988	8.97%
4/28/2009	3.9537	3.95%	3.78%	7/15/1988	8.97%
4/27/2009	3.8294	3.83%	3.79%	7/18/1988	8.97%
4/24/2009	3.8813	3.88%	3.79%	7/19/1988	8.97%
4/23/2009	3.7918	3.79%	3.79%	7/20/1988	8.96%
4/22/2009	3.8036	3.80%	3.80%	7/21/1988	8.96%
4/21/2009	3.7392	3.74%	3.80%	7/22/1988	8.96%
4/20/2009	3.6891	3.69%	3.80%	7/25/1988	8.95%
4/17/2009	3.7981	3.80%	3.81%	7/26/1988	8.95%
4/16/2009	3.714	3.71%	3.81%	7/27/1988	8.95%
4/15/2009	3.6625	3.66%	3.82%	7/28/1988	8.95%
4/14/2009	3.6545	3.65%	3.82%	7/29/1988	8.94%
4/13/2009	3.7104	3.71%	3.82%	8/1/1988	8.94%
4/10/2009	3.7499	3.75%	3.83%	8/2/1988	8.93%
4/9/2009	3.7517	3.75%	3.83%	8/3/1988	8.93%
4/8/2009	3.6686	3.67%	3.83%	8/4/1988	8.92%
4/7/2009	3.7139	3.71%	3.84%	8/5/1988	8.92%
4/6/2009	3.7247	3.72%	3.84%	8/8/1988	8.91%
4/3/2009	3.6899	3.69%	3.85%	8/9/1988	8.91%
4/2/2009	3.5968	3.60%	3.85%	8/10/1988	8.91%
4/1/2009	3.5015	3.50%	3.86%	8/11/1988	8.91%
3/31/2009	3.5339	3.53%	3.86%	8/12/1988	8.92%
3/30/2009	3.5985	3.60%	3.87%	8/15/1988	8.92%
3/27/2009	3.6124	3.61%	3.87%	8/16/1988	8.92%
3/26/2009	3.6518	3.65%	3.88%	8/17/1988	8.92%
3/25/2009	3.7407	3.74%	3.88%	8/18/1988	8.92%
3/24/2009	3.6386	3.64%	3.89%	8/19/1988	8.93%
3/23/2009	3.6915	3.69%	3.89%	8/22/1988	8.93%
3/20/2009	3.6606	3.66%	3.90%	8/23/1988	8.93%
3/19/2009	3.629	3.63%	3.91%	8/24/1988	8.93%

3/18/2009	3.5322	3.53%	3.91%	8/25/1988	8.93%
3/17/2009	3.8251	3.83%	3.92%	8/26/1988	8.94%
3/16/2009	3.7577	3.76%	3.92%	8/29/1988	8.94%
3/13/2009	3.6729	3.67%	3.93%	8/30/1988	8.94%
3/12/2009	3.6106	3.61%	3.93%	8/31/1988	8.94%
3/11/2009	3.6614	3.66%	3.94%	9/1/1988	8.95%
3/10/2009	3.7253	3.73%	3.94%	9/2/1988	8.95%
3/9/2009	3.5665	3.57%	3.95%	9/6/1988	8.95%
3/6/2009	3.5536	3.55%	3.95%	9/7/1988	8.95%
3/5/2009	3.4881	3.49%	3.96%	9/8/1988	8.95%
3/4/2009	3.6667	3.67%	3.96%	9/9/1988	8.95%
3/3/2009	3.601	3.60%	3.97%	9/12/1988	8.95%
3/2/2009	3.6106	3.61%	3.97%	9/13/1988	8.95%
2/27/2009	3.7083	3.71%	3.98%	9/14/1988	8.95%
2/26/2009	3.6746	3.67%	3.98%	9/15/1988	8.95%
2/25/2009	3.5872	3.59%	3.99%	9/16/1988	8.95%
2/24/2009	3.4924	3.49%	3.99%	9/19/1988	8.95%
2/23/2009	3.5067	3.51%	4.00%	9/20/1988	8.95%
2/20/2009	3.5673	3.57%	4.00%	9/21/1988	8.95%
2/19/2009	3.6701	3.67%	4.01%	9/22/1988	8.95%
2/18/2009	3.5468	3.55%	4.01%	9/23/1988	8.95%
2/17/2009	3.4797	3.48%	4.02%	9/26/1988	8.95%
2/16/2009	3.671	3.67%	4.02%	9/27/1988	8.94%
2/13/2009	3.6728	3.67%	4.03%	9/28/1988	8.94%
2/12/2009	3.5196	3.52%	4.03%	9/29/1988	8.94%
2/11/2009	3.4443	3.44%	4.04%	9/30/1988	8.94%
2/10/2009	3.4875	3.49%	4.04%	10/3/1988	8.94%
2/9/2009	3.6452	3.65%	4.05%	10/4/1988	8.94%
2/6/2009	3.6961	3.70%	4.05%	10/5/1988	8.94%
2/5/2009	3.6477	3.65%	4.06%	10/6/1988	8.94%
2/4/2009	3.6811	3.68%	4.06%	10/7/1988	8.94%
2/3/2009	3.6771	3.68%	4.07%	10/11/1988	8.93%
2/2/2009	3.4743	3.47%	4.07%	10/12/1988	8.93%
1/30/2009	3.603	3.60%	4.08%	10/13/1988	8.93%
1/29/2009	3.6063	3.61%	4.08%	10/14/1988	8.93%
1/28/2009	3.4232	3.42%	4.09%	10/17/1988	8.93%
1/27/2009	3.2435	3.24%	4.09%	10/18/1988	8.93%
1/26/2009	3.3771	3.38%	4.10%	10/19/1988	8.93%
1/23/2009	3.3212	3.32%	4.10%	10/20/1988	8.93%
1/22/2009	3.2575	3.26%	4.11%	10/21/1988	8.93%
1/21/2009	3.1579	3.16%	4.12%	10/24/1988	8.93%
1/20/2009	2.9804	2.98%	4.12%	10/25/1988	8.93%
1/19/2009	2.8747	2.87%	4.13%	10/26/1988	8.93%
1/16/2009	2.8747	2.87%	4.14%	10/27/1988	8.93%
1/15/2009	2.8672	2.87%	4.14%	10/28/1988	8.93%
1/14/2009	2.8863	2.89%	4.15%	10/31/1988	8.93%
1/13/2009	3.0026	3.00%	4.16%	11/1/1988	8.93%

1/12/2009	2.9898	2.99%	4.16%	11/2/1988	8.93%
1/9/2009	3.06	3.06%	4.17%	11/3/1988	8.93%
1/8/2009	3.0458	3.05%	4.18%	11/4/1988	8.93%
1/7/2009	3.0363	3.04%	4.18%	11/7/1988	8.93%
1/6/2009	2.995	3.00%	4.19%	11/8/1988	8.93%
1/5/2009	3.0283	3.03%	4.20%	11/9/1988	8.93%
1/2/2009	2.7948	2.79%	4.20%	11/10/1988	8.93%
1/1/2009	2.6756	2.68%	4.21%	11/14/1988	8.94%
12/31/2008	2.6758	2.68%	4.22%	11/15/1988	8.94%
12/30/2008	2.5548	2.55%	4.23%	11/16/1988	8.94%
12/29/2008	2.632	2.63%	4.24%	11/17/1988	8.95%
12/26/2008	2.6056	2.61%	4.25%	11/18/1988	8.95%
12/25/2008	2.6315	2.63%	4.25%	11/21/1988	8.95%
12/24/2008	2.6318	2.63%	4.26%	11/22/1988	8.96%
12/23/2008	2.6375	2.64%	4.27%	11/23/1988	8.96%
12/22/2008	2.6166	2.62%	4.28%	11/25/1988	8.96%
12/19/2008	2.5502	2.55%	4.29%	11/28/1988	8.97%
12/18/2008	2.521	2.52%	4.30%	11/29/1988	8.97%
12/17/2008	2.6505	2.65%	4.31%	11/30/1988	8.98%
12/16/2008	2.7352	2.74%	4.31%	12/1/1988	8.98%
12/15/2008	2.955	2.96%	4.32%	12/2/1988	8.98%
12/12/2008	3.0436	3.04%	4.33%	12/5/1988	8.99%
12/11/2008	3.0609	3.06%	4.34%	12/6/1988	8.99%
12/10/2008	3.0857	3.09%	4.35%	12/7/1988	8.99%
12/9/2008	3.0412	3.04%	4.35%	12/8/1988	8.99%
12/8/2008	3.1504	3.15%	4.36%	12/9/1988	9.00%
12/5/2008	3.1254	3.13%	4.37%	12/12/1988	9.00%
12/4/2008	3.0409	3.04%	4.37%	12/13/1988	9.00%
12/3/2008	3.162	3.16%	4.38%	12/14/1988	9.01%
12/2/2008	3.174	3.17%	4.39%	12/15/1988	9.01%
12/1/2008	3.2136	3.21%	4.40%	12/16/1988	9.01%
11/28/2008	3.4369	3.44%	4.40%	12/19/1988	9.02%
11/27/2008	3.5225	3.52%	4.41%	12/20/1988	9.02%
11/26/2008	3.5226	3.52%	4.41%	12/21/1988	9.02%
11/25/2008	3.6194	3.62%	4.42%	12/22/1988	9.02%
11/24/2008	3.7805	3.78%	4.42%	12/23/1988	9.03%
11/21/2008	3.6937	3.69%	4.43%	12/27/1988	9.03%
11/20/2008	3.4857	3.49%	4.43%	12/28/1988	9.03%
11/19/2008	3.9053	3.91%	4.44%	12/29/1988	9.03%
11/18/2008	4.1138	4.11%	4.44%	12/30/1988	9.04%
11/17/2008	4.1919	4.19%	4.44%	1/3/1989	9.04%
11/14/2008	4.2279	4.23%	4.44%	1/4/1989	9.04%
11/13/2008	4.3562	4.36%	4.45%	1/5/1989	9.04%
11/12/2008	4.1687	4.17%	4.45%	1/6/1989	9.04%
11/11/2008	4.192	4.19%	4.45%	1/9/1989	9.05%
11/10/2008	4.192	4.19%	4.45%	1/10/1989	9.05%
11/7/2008	4.2733	4.27%	4.45%	1/11/1989	9.05%

11/6/2008	4.1983	4.20%	4.45%	1/12/1989	9.05%
11/5/2008	4.175	4.18%	4.45%	1/13/1989	9.05%
11/4/2008	4.192	4.19%	4.45%	1/17/1989	9.05%
11/3/2008	4.3219	4.32%	4.45%	1/18/1989	9.05%
10/31/2008	4.3664	4.37%	4.45%	1/19/1989	9.05%
10/30/2008	4.3302	4.33%	4.45%	1/20/1989	9.05%
10/29/2008	4.237	4.24%	4.45%	1/23/1989	9.05%
10/28/2008	4.1912	4.19%	4.45%	1/24/1989	9.05%
10/27/2008	4.0453	4.05%	4.45%	1/25/1989	9.05%
10/24/2008	4.0687	4.07%	4.45%	1/26/1989	9.05%
10/23/2008	4.0496	4.05%	4.45%	1/27/1989	9.05%
10/22/2008	4.0548	4.05%	4.45%	1/30/1989	9.05%
10/21/2008	4.2163	4.22%	4.46%	1/31/1989	9.05%
10/20/2008	4.2552	4.26%	4.46%	2/1/1989	9.06%
10/17/2008	4.3229	4.32%	4.46%	2/2/1989	9.05%
10/16/2008	4.2561	4.26%	4.46%	2/3/1989	9.05%
10/15/2008	4.1913	4.19%	4.46%	2/6/1989	9.05%
10/14/2008	4.2761	4.28%	4.46%	2/7/1989	9.05%
10/13/2008	4.1362	4.14%	4.46%	2/8/1989	9.05%
10/10/2008	4.1363	4.14%	4.46%	2/9/1989	9.05%
10/9/2008	4.102	4.10%	4.46%	2/10/1989	9.05%
10/8/2008	4.0482	4.05%	4.46%	2/13/1989	9.05%
10/7/2008	4.0301	4.03%	4.46%	2/14/1989	9.05%
10/6/2008	3.972	3.97%	4.47%	2/15/1989	9.05%
10/3/2008	4.0872	4.09%	4.47%	2/16/1989	9.05%
10/2/2008	4.1514	4.15%	4.47%	2/17/1989	9.05%
10/1/2008	4.2147	4.21%	4.47%	2/21/1989	9.05%
9/30/2008	4.311	4.31%	4.48%	2/22/1989	9.05%
9/29/2008	4.1127	4.11%	4.48%	2/23/1989	9.05%
9/26/2008	4.3702	4.37%	4.48%	2/24/1989	9.05%
9/25/2008	4.4095	4.41%	4.48%	2/27/1989	9.05%
9/24/2008	4.4123	4.41%	4.48%	2/28/1989	9.05%
9/23/2008	4.3805	4.38%	4.48%	3/1/1989	9.05%
9/22/2008	4.4208	4.42%	4.48%	3/2/1989	9.05%
9/19/2008	4.3823	4.38%	4.48%	3/3/1989	9.05%
9/18/2008	4.1889	4.19%	4.48%	3/6/1989	9.05%
9/17/2008	4.0736	4.07%	4.49%	3/7/1989	9.05%
9/16/2008	4.091	4.09%	4.49%	3/8/1989	9.05%
9/15/2008	4.0227	4.02%	4.49%	3/9/1989	9.05%
9/12/2008	4.3147	4.31%	4.49%	3/10/1989	9.05%
9/11/2008	4.2212	4.22%	4.49%	3/13/1989	9.05%
9/10/2008	4.2257	4.23%	4.50%	3/14/1989	9.05%
9/9/2008	4.1703	4.17%	4.50%	3/15/1989	9.05%
9/8/2008	4.2664	4.27%	4.50%	3/16/1989	9.04%
9/5/2008	4.3019	4.30%	4.50%	3/17/1989	9.04%
9/4/2008	4.2592	4.26%	4.50%	3/20/1989	9.04%
9/3/2008	4.3185	4.32%	4.50%	3/21/1989	9.04%

9/2/2008	4.3554	4.36%	4.50%	3/22/1989	9.05%
9/1/2008	4.4227	4.42%	4.50%	3/23/1989	9.05%
8/29/2008	4.4227	4.42%	4.50%	3/27/1989	9.05%
8/28/2008	4.3759	4.38%	4.50%	3/28/1989	9.05%
8/27/2008	4.3815	4.38%	4.50%	3/29/1989	9.05%
8/26/2008	4.3871	4.39%	4.50%	3/30/1989	9.05%
8/25/2008	4.3936	4.39%	4.50%	3/31/1989	9.05%
8/22/2008	4.4662	4.47%	4.50%	4/3/1989	9.05%
8/21/2008	4.4624	4.46%	4.50%	4/4/1989	9.05%
8/20/2008	4.4453	4.45%	4.50%	4/5/1989	9.05%
8/19/2008	4.4615	4.46%	4.50%	4/6/1989	9.05%
8/18/2008	4.434	4.43%	4.50%	4/7/1989	9.05%
8/15/2008	4.4634	4.46%	4.50%	4/10/1989	9.05%
8/14/2008	4.5169	4.52%	4.50%	4/11/1989	9.05%
8/13/2008	4.5594	4.56%	4.50%	4/12/1989	9.05%
8/12/2008	4.5333	4.53%	4.51%	4/13/1989	9.05%
8/11/2008	4.6024	4.60%	4.51%	4/14/1989	9.05%
8/8/2008	4.5333	4.53%	4.51%	4/17/1989	9.05%
8/7/2008	4.555	4.56%	4.51%	4/18/1989	9.05%
8/6/2008	4.6925	4.69%	4.51%	4/19/1989	9.05%
8/5/2008	4.6408	4.64%	4.51%	4/20/1989	9.05%
8/4/2008	4.5896	4.59%	4.51%	4/21/1989	9.06%
8/1/2008	4.5608	4.56%	4.51%	4/24/1989	9.06%
7/31/2008	4.5727	4.57%	4.51%	4/25/1989	9.06%
7/30/2008	4.6447	4.64%	4.51%	4/26/1989	9.06%
7/29/2008	4.6235	4.62%	4.51%	4/27/1989	9.05%
7/28/2008	4.6015	4.60%	4.51%	4/28/1989	9.05%
7/25/2008	4.6852	4.69%	4.51%	5/1/1989	9.05%
7/24/2008	4.6014	4.60%	4.51%	5/2/1989	9.05%
7/23/2008	4.6739	4.67%	4.51%	5/3/1989	9.05%
7/22/2008	4.6587	4.66%	4.51%	5/4/1989	9.05%
7/21/2008	4.6214	4.62%	4.51%	5/5/1989	9.05%
7/18/2008	4.6475	4.65%	4.51%	5/8/1989	9.05%
7/17/2008	4.6073	4.61%	4.52%	5/9/1989	9.05%
7/16/2008	4.5853	4.59%	4.52%	5/10/1989	9.05%
7/15/2008	4.458	4.46%	4.52%	5/11/1989	9.05%
7/14/2008	4.4464	4.45%	4.52%	5/12/1989	9.04%
7/11/2008	4.5398	4.54%	4.52%	5/15/1989	9.04%
7/10/2008	4.4138	4.41%	4.52%	5/16/1989	9.04%
7/9/2008	4.4176	4.42%	4.53%	5/17/1989	9.04%
7/8/2008	4.4502	4.45%	4.53%	5/18/1989	9.04%
7/7/2008	4.484	4.48%	4.53%	5/19/1989	9.03%
7/4/2008	4.5328	4.53%	4.53%	5/22/1989	9.03%
7/3/2008	4.5348	4.53%	4.53%	5/23/1989	9.03%
7/2/2008	4.5025	4.50%	4.53%	5/24/1989	9.03%
7/1/2008	4.5485	4.55%	4.54%	5/25/1989	9.03%
6/30/2008	4.5239	4.52%	4.54%	5/26/1989	9.02%

6/27/2008	4.521	4.52%	4.54%	5/29/1989	9.02%
6/26/2008	4.601	4.60%	4.54%	5/30/1989	9.02%
6/25/2008	4.643	4.64%	4.54%	5/31/1989	9.01%
6/24/2008	4.636	4.64%	4.54%	6/1/1989	9.01%
6/23/2008	4.7008	4.70%	4.54%	6/2/1989	9.00%
6/20/2008	4.7243	4.72%	4.54%	6/5/1989	9.00%
6/19/2008	4.7582	4.76%	4.54%	6/6/1989	8.99%
6/18/2008	4.713	4.71%	4.54%	6/7/1989	8.99%
6/17/2008	4.7675	4.77%	4.54%	6/8/1989	8.98%
6/16/2008	4.7914	4.79%	4.54%	6/9/1989	8.98%
6/13/2008	4.7893	4.79%	4.54%	6/12/1989	8.97%
6/12/2008	4.7571	4.76%	4.54%	6/13/1989	8.96%
6/11/2008	4.6945	4.69%	4.54%	6/14/1989	8.96%
6/10/2008	4.6985	4.70%	4.54%	6/15/1989	8.95%
6/9/2008	4.6297	4.63%	4.54%	6/16/1989	8.95%
6/6/2008	4.6237	4.62%	4.54%	6/19/1989	8.94%
6/5/2008	4.7363	4.74%	4.54%	6/20/1989	8.94%
6/4/2008	4.6984	4.70%	4.55%	6/21/1989	8.93%
6/3/2008	4.6206	4.62%	4.55%	6/22/1989	8.93%
6/2/2008	4.67	4.67%	4.55%	6/23/1989	8.92%
5/30/2008	4.7147	4.71%	4.55%	6/26/1989	8.92%
5/29/2008	4.7475	4.75%	4.55%	6/27/1989	8.91%
5/28/2008	4.6881	4.69%	4.55%	6/28/1989	8.91%
5/27/2008	4.6406	4.64%	4.55%	6/29/1989	8.91%
5/26/2008	4.5728	4.57%	4.55%	6/30/1989	8.90%
5/23/2008	4.5678	4.57%	4.56%	7/3/1989	8.90%
5/22/2008	4.6205	4.62%	4.56%	7/5/1989	8.89%
5/21/2008	4.5392	4.54%	4.56%	7/6/1989	8.89%
5/20/2008	4.5294	4.53%	4.56%	7/7/1989	8.88%
5/19/2008	4.5717	4.57%	4.56%	7/10/1989	8.88%
5/16/2008	4.5737	4.57%	4.57%	7/11/1989	8.87%
5/15/2008	4.551	4.55%	4.57%	7/12/1989	8.87%
5/14/2008	4.6134	4.61%	4.57%	7/13/1989	8.86%
5/13/2008	4.6384	4.64%	4.57%	7/14/1989	8.86%
5/12/2008	4.5343	4.53%	4.57%	7/17/1989	8.85%
5/9/2008	4.5216	4.52%	4.58%	7/18/1989	8.85%
5/8/2008	4.5421	4.54%	4.58%	7/19/1989	8.84%
5/7/2008	4.6054	4.61%	4.58%	7/20/1989	8.84%
5/6/2008	4.6625	4.66%	4.58%	7/21/1989	8.83%
5/5/2008	4.6014	4.60%	4.58%	7/24/1989	8.83%
5/2/2008	4.5775	4.58%	4.58%	7/25/1989	8.83%
5/1/2008	4.4991	4.50%	4.59%	7/26/1989	8.82%
4/30/2008	4.4672	4.47%	4.59%	7/27/1989	8.82%
4/29/2008	4.5509	4.55%	4.59%	7/28/1989	8.81%
4/28/2008	4.5597	4.56%	4.59%	7/31/1989	8.81%
4/25/2008	4.5914	4.59%	4.60%	8/1/1989	8.80%
4/24/2008	4.5459	4.55%	4.60%	8/2/1989	8.80%

4/23/2008	4.4913	4.49%	4.60%	8/3/1989	8.79%
4/22/2008	4.4441	4.44%	4.60%	8/4/1989	8.79%
4/21/2008	4.4884	4.49%	4.61%	8/7/1989	8.79%
4/18/2008	4.4961	4.50%	4.61%	8/8/1989	8.78%
4/17/2008	4.5263	4.53%	4.61%	8/9/1989	8.78%
4/16/2008	4.4932	4.49%	4.62%	8/10/1989	8.77%
4/15/2008	4.4412	4.44%	4.62%	8/11/1989	8.77%
4/14/2008	4.3493	4.35%	4.62%	8/14/1989	8.77%
4/11/2008	4.299	4.30%	4.63%	8/15/1989	8.76%
4/10/2008	4.3484	4.35%	4.63%	8/16/1989	8.76%
4/9/2008	4.3204	4.32%	4.64%	8/17/1989	8.76%
4/8/2008	4.3794	4.38%	4.64%	8/18/1989	8.75%
4/7/2008	4.3447	4.34%	4.65%	8/21/1989	8.75%
4/4/2008	4.3055	4.31%	4.65%	8/22/1989	8.75%
4/3/2008	4.3785	4.38%	4.65%	8/23/1989	8.74%
4/2/2008	4.405	4.41%	4.66%	8/24/1989	8.74%
4/1/2008	4.3993	4.40%	4.66%	8/25/1989	8.74%
3/31/2008	4.2917	4.29%	4.67%	8/28/1989	8.73%
3/28/2008	4.3177	4.32%	4.67%	8/29/1989	8.73%
3/27/2008	4.3898	4.39%	4.68%	8/30/1989	8.73%
3/26/2008	4.3065	4.31%	4.68%	8/31/1989	8.72%
3/25/2008	4.3028	4.30%	4.68%	9/1/1989	8.72%
3/24/2008	4.3644	4.36%	4.69%	9/4/1989	8.71%
3/21/2008	4.1599	4.16%	4.69%	9/5/1989	8.71%
3/20/2008	4.1599	4.16%	4.70%	9/6/1989	8.70%
3/19/2008	4.2104	4.21%	4.70%	9/7/1989	8.70%
3/18/2008	4.3485	4.35%	4.71%	9/8/1989	8.69%
3/17/2008	4.2854	4.29%	4.71%	9/11/1989	8.69%
3/14/2008	4.3635	4.36%	4.72%	9/12/1989	8.68%
3/13/2008	4.447	4.45%	4.72%	9/13/1989	8.68%
3/12/2008	4.4098	4.41%	4.73%	9/14/1989	8.67%
3/11/2008	4.5077	4.51%	4.73%	9/15/1989	8.67%
3/10/2008	4.4633	4.46%	4.73%	9/18/1989	8.66%
3/7/2008	4.5399	4.54%	4.74%	9/19/1989	8.66%
3/6/2008	4.5605	4.56%	4.74%	9/20/1989	8.65%
3/5/2008	4.598	4.60%	4.74%	9/21/1989	8.65%
3/4/2008	4.5068	4.51%	4.74%	9/22/1989	8.64%
3/3/2008	4.4327	4.43%	4.75%	9/25/1989	8.64%
2/29/2008	4.4023	4.40%	4.75%	9/26/1989	8.64%
2/28/2008	4.5213	4.52%	4.75%	9/27/1989	8.63%
2/27/2008	4.6499	4.65%	4.75%	9/28/1989	8.63%
2/26/2008	4.6559	4.66%	4.76%	9/29/1989	8.63%
2/25/2008	4.6549	4.65%	4.76%	10/2/1989	8.62%
2/22/2008	4.5733	4.57%	4.76%	10/3/1989	8.62%
2/21/2008	4.5438	4.54%	4.76%	10/4/1989	8.61%
2/20/2008	4.6079	4.61%	4.76%	10/5/1989	8.61%
2/19/2008	4.6649	4.66%	4.76%	10/6/1989	8.60%

2/18/2008	4.5762	4.58%	4.77%	10/9/1989	8.60%
2/15/2008	4.5762	4.58%	4.77%	10/10/1989	8.59%
2/14/2008	4.6368	4.64%	4.77%	10/11/1989	8.59%
2/13/2008	4.537	4.54%	4.77%	10/12/1989	8.59%
2/12/2008	4.4576	4.46%	4.77%	10/13/1989	8.58%
2/11/2008	4.3986	4.40%	4.77%	10/16/1989	8.57%
2/8/2008	4.4166	4.42%	4.77%	10/17/1989	8.57%
2/7/2008	4.5177	4.52%	4.78%	10/18/1989	8.56%
2/6/2008	4.3549	4.35%	4.78%	10/19/1989	8.56%
2/5/2008	4.3258	4.33%	4.78%	10/20/1989	8.55%
2/4/2008	4.3779	4.38%	4.78%	10/23/1989	8.55%
2/1/2008	4.3084	4.31%	4.78%	10/24/1989	8.54%
1/31/2008	4.3225	4.32%	4.79%	10/25/1989	8.54%
1/30/2008	4.3843	4.38%	4.79%	10/26/1989	8.53%
1/29/2008	4.3551	4.36%	4.79%	10/27/1989	8.53%
1/28/2008	4.2781	4.28%	4.80%	10/30/1989	8.52%
1/25/2008	4.2634	4.26%	4.80%	10/31/1989	8.52%
1/24/2008	4.3925	4.39%	4.80%	11/1/1989	8.51%
1/23/2008	4.314	4.31%	4.80%	11/2/1989	8.51%
1/22/2008	4.1942	4.19%	4.81%	11/3/1989	8.50%
1/21/2008	4.2809	4.28%	4.81%	11/6/1989	8.50%
1/18/2008	4.281	4.28%	4.81%	11/7/1989	8.49%
1/17/2008	4.2551	4.26%	4.81%	11/8/1989	8.49%
1/16/2008	4.3423	4.34%	4.82%	11/9/1989	8.49%
1/15/2008	4.2725	4.27%	4.82%	11/10/1989	8.48%
1/14/2008	4.3582	4.36%	4.82%	11/13/1989	8.48%
1/11/2008	4.375	4.38%	4.83%	11/14/1989	8.47%
1/10/2008	4.4502	4.45%	4.83%	11/15/1989	8.47%
1/9/2008	4.3407	4.34%	4.83%	11/16/1989	8.46%
1/8/2008	4.3101	4.31%	4.83%	11/17/1989	8.46%
1/7/2008	4.3382	4.34%	4.84%	11/20/1989	8.45%
1/4/2008	4.3761	4.38%	4.84%	11/21/1989	8.45%
1/3/2008	4.3638	4.36%	4.84%	11/22/1989	8.44%
1/2/2008	4.3524	4.35%	4.84%	11/23/1989	8.44%
1/1/2008	4.4522	4.45%	4.85%	11/24/1989	8.43%
12/31/2007	4.4522	4.45%	4.85%	11/27/1989	8.42%
12/28/2007	4.4949	4.49%	4.85%	11/28/1989	8.42%
12/27/2007	4.6111	4.61%	4.85%	11/29/1989	8.41%
12/26/2007	4.6704	4.67%	4.85%	11/30/1989	8.41%
12/25/2007	4.6149	4.61%	4.85%	12/1/1989	8.40%
12/24/2007	4.6149	4.61%	4.85%	12/4/1989	8.39%
12/21/2007	4.5823	4.58%	4.85%	12/5/1989	8.39%
12/20/2007	4.4788	4.48%	4.85%	12/6/1989	8.38%
12/19/2007	4.4472	4.45%	4.86%	12/7/1989	8.37%
12/18/2007	4.5354	4.54%	4.86%	12/8/1989	8.37%
12/17/2007	4.5788	4.58%	4.86%	12/11/1989	8.36%
12/14/2007	4.6583	4.66%	4.86%	12/12/1989	8.36%

12/13/2007	4.6105	4.61%	4.86%	12/13/1989	8.35%
12/12/2007	4.5411	4.54%	4.86%	12/14/1989	8.34%
12/11/2007	4.4664	4.47%	4.86%	12/15/1989	8.34%
12/10/2007	4.619	4.62%	4.86%	12/18/1989	8.33%
12/7/2007	4.5697	4.57%	4.86%	12/19/1989	8.33%
12/6/2007	4.4756	4.48%	4.86%	12/20/1989	8.32%
12/5/2007	4.4413	4.44%	4.86%	12/21/1989	8.31%
12/4/2007	4.356	4.36%	4.86%	12/22/1989	8.31%
12/3/2007	4.3253	4.33%	4.86%	12/26/1989	8.30%
11/30/2007	4.379	4.38%	4.87%	12/27/1989	8.29%
11/29/2007	4.3456	4.35%	4.87%	12/28/1989	8.29%
11/28/2007	4.4183	4.42%	4.87%	12/29/1989	8.28%
11/27/2007	4.3633	4.36%	4.87%	1/2/1990	8.27%
11/26/2007	4.2899	4.29%	4.87%	1/3/1990	8.27%
11/23/2007	4.4246	4.42%	4.88%	1/4/1990	8.26%
11/22/2007	4.4587	4.46%	4.88%	1/5/1990	8.26%
11/21/2007	4.4588	4.46%	4.88%	1/8/1990	8.25%
11/20/2007	4.4978	4.50%	4.88%	1/9/1990	8.25%
11/19/2007	4.4761	4.48%	4.88%	1/10/1990	8.24%
11/16/2007	4.5344	4.53%	4.89%	1/11/1990	8.24%
11/15/2007	4.5189	4.52%	4.89%	1/12/1990	8.23%
11/14/2007	4.5972	4.60%	4.89%	1/15/1990	8.23%
11/13/2007	4.615	4.62%	4.89%	1/16/1990	8.22%
11/12/2007	4.6028	4.60%	4.89%	1/17/1990	8.22%
11/9/2007	4.6028	4.60%	4.89%	1/18/1990	8.22%
11/8/2007	4.6676	4.67%	4.89%	1/19/1990	8.21%
11/7/2007	4.6534	4.65%	4.90%	1/22/1990	8.21%
11/6/2007	4.6666	4.67%	4.90%	1/23/1990	8.20%
11/5/2007	4.6272	4.63%	4.90%	1/24/1990	8.20%
11/2/2007	4.6159	4.62%	4.90%	1/25/1990	8.20%
11/1/2007	4.6365	4.64%	4.90%	1/26/1990	8.20%
10/31/2007	4.7457	4.75%	4.90%	1/29/1990	8.19%
10/30/2007	4.6742	4.67%	4.91%	1/30/1990	8.19%
10/29/2007	4.6638	4.66%	4.91%	1/31/1990	8.19%
10/26/2007	4.6979	4.70%	4.91%	2/1/1990	8.19%
10/25/2007	4.6828	4.68%	4.91%	2/2/1990	8.18%
10/24/2007	4.6422	4.64%	4.91%	2/5/1990	8.18%
10/23/2007	4.6942	4.69%	4.91%	2/6/1990	8.18%
10/22/2007	4.6885	4.69%	4.91%	2/7/1990	8.18%
10/19/2007	4.6856	4.69%	4.91%	2/8/1990	8.18%
10/18/2007	4.7698	4.77%	4.91%	2/9/1990	8.17%
10/17/2007	4.8252	4.83%	4.91%	2/12/1990	8.17%
10/16/2007	4.9031	4.90%	4.91%	2/13/1990	8.17%
10/15/2007	4.9121	4.91%	4.91%	2/14/1990	8.16%
10/12/2007	4.9011	4.90%	4.91%	2/15/1990	8.16%
10/11/2007	4.8635	4.86%	4.91%	2/16/1990	8.16%
10/10/2007	4.8674	4.87%	4.91%	2/19/1990	8.16%

10/9/2007	4.8615	4.86%	4.91%	2/20/1990	8.15%
10/8/2007	4.8655	4.87%	4.91%	2/21/1990	8.15%
10/5/2007	4.8655	4.87%	4.91%	2/22/1990	8.15%
10/4/2007	4.7564	4.76%	4.91%	2/23/1990	8.15%
10/3/2007	4.796	4.80%	4.91%	2/26/1990	8.15%
10/2/2007	4.767	4.77%	4.91%	2/27/1990	8.15%
10/1/2007	4.7863	4.79%	4.91%	2/28/1990	8.15%
9/28/2007	4.836	4.84%	4.91%	3/1/1990	8.15%
9/27/2007	4.834	4.83%	4.91%	3/2/1990	8.15%
9/26/2007	4.8922	4.89%	4.91%	3/5/1990	8.15%
9/25/2007	4.9021	4.90%	4.91%	3/6/1990	8.15%
9/24/2007	4.8823	4.88%	4.90%	3/7/1990	8.15%
9/21/2007	4.8852	4.89%	4.90%	3/8/1990	8.15%
9/20/2007	4.9642	4.96%	4.90%	3/9/1990	8.15%
9/19/2007	4.835	4.84%	4.90%	3/12/1990	8.15%
9/18/2007	4.7545	4.75%	4.90%	3/13/1990	8.15%
9/17/2007	4.6982	4.70%	4.90%	3/14/1990	8.15%
9/14/2007	4.7191	4.72%	4.90%	3/15/1990	8.15%
9/13/2007	4.7325	4.73%	4.90%	3/16/1990	8.15%
9/12/2007	4.6859	4.69%	4.90%	3/19/1990	8.15%
9/11/2007	4.653	4.65%	4.90%	3/20/1990	8.15%
9/10/2007	4.6371	4.64%	4.90%	3/21/1990	8.15%
9/7/2007	4.6973	4.70%	4.90%	3/22/1990	8.15%
9/6/2007	4.7951	4.80%	4.90%	3/23/1990	8.15%
9/5/2007	4.77	4.77%	4.90%	3/26/1990	8.16%
9/4/2007	4.8302	4.83%	4.89%	3/27/1990	8.16%
9/3/2007	4.8224	4.82%	4.89%	3/28/1990	8.16%
8/31/2007	4.8224	4.82%	4.89%	3/29/1990	8.16%
8/30/2007	4.8244	4.82%	4.89%	3/30/1990	8.16%
8/29/2007	4.8793	4.88%	4.89%	4/2/1990	8.16%
8/28/2007	4.84	4.84%	4.89%	4/3/1990	8.16%
8/27/2007	4.8577	4.86%	4.89%	4/4/1990	8.17%
8/24/2007	4.8843	4.88%	4.89%	4/5/1990	8.17%
8/23/2007	4.936	4.94%	4.89%	4/6/1990	8.17%
8/22/2007	4.9611	4.96%	4.89%	4/9/1990	8.17%
8/21/2007	4.948	4.95%	4.88%	4/10/1990	8.17%
8/20/2007	4.9651	4.97%	4.88%	4/11/1990	8.18%
8/17/2007	4.9863	4.99%	4.88%	4/12/1990	8.18%
8/16/2007	4.9581	4.96%	4.88%	4/13/1990	8.18%
8/15/2007	5.026	5.03%	4.88%	4/16/1990	8.18%
8/14/2007	4.9884	4.99%	4.88%	4/17/1990	8.19%
8/13/2007	4.9995	5.00%	4.88%	4/18/1990	8.19%
8/10/2007	5.0331	5.03%	4.88%	4/19/1990	8.20%
8/9/2007	5.0204	5.02%	4.87%	4/20/1990	8.20%
8/8/2007	5.0404	5.04%	4.87%	4/23/1990	8.21%
8/7/2007	4.9267	4.93%	4.87%	4/24/1990	8.21%
8/6/2007	4.9092	4.91%	4.87%	4/25/1990	8.21%

8/3/2007	4.8652	4.87%	4.87%	4/26/1990	8.22%
8/2/2007	4.9122	4.91%	4.87%	4/27/1990	8.22%
8/1/2007	4.9224	4.92%	4.87%	4/30/1990	8.23%
7/31/2007	4.9019	4.90%	4.87%	5/1/1990	8.23%
7/30/2007	4.9544	4.95%	4.87%	5/2/1990	8.24%
7/27/2007	4.9317	4.93%	4.87%	5/3/1990	8.24%
7/26/2007	4.9533	4.95%	4.87%	5/4/1990	8.24%
7/25/2007	5.0243	5.02%	4.87%	5/7/1990	8.25%
7/24/2007	5.0296	5.03%	4.87%	5/8/1990	8.25%
7/23/2007	5.057	5.06%	4.87%	5/9/1990	8.26%
7/20/2007	5.0581	5.06%	4.87%	5/10/1990	8.26%
7/19/2007	5.1092	5.11%	4.87%	5/11/1990	8.27%
7/18/2007	5.1232	5.12%	4.86%	5/14/1990	8.27%
7/17/2007	5.1383	5.14%	4.86%	5/15/1990	8.27%
7/16/2007	5.1264	5.13%	4.86%	5/16/1990	8.27%
7/13/2007	5.1849	5.18%	4.86%	5/17/1990	8.28%
7/12/2007	5.2221	5.22%	4.86%	5/18/1990	8.28%
7/11/2007	5.1902	5.19%	4.86%	5/21/1990	8.28%
7/10/2007	5.1176	5.12%	4.85%	5/22/1990	8.29%
7/9/2007	5.2363	5.24%	4.85%	5/23/1990	8.29%
7/6/2007	5.2684	5.27%	4.85%	5/24/1990	8.29%
7/5/2007	5.2308	5.23%	4.85%	5/25/1990	8.29%
7/4/2007	5.139	5.14%	4.85%	5/28/1990	8.30%
7/3/2007	5.139	5.14%	4.84%	5/29/1990	8.30%
7/2/2007	5.0896	5.09%	4.84%	5/30/1990	8.30%
6/29/2007	5.1239	5.12%	4.84%	5/31/1990	8.30%
6/28/2007	5.202	5.20%	4.84%	6/1/1990	8.30%
6/27/2007	5.1943	5.19%	4.83%	6/4/1990	8.30%
6/26/2007	5.1986	5.20%	4.83%	6/5/1990	8.31%
6/25/2007	5.203	5.20%	4.83%	6/6/1990	8.31%
6/22/2007	5.2481	5.25%	4.83%	6/7/1990	8.31%
6/21/2007	5.3037	5.30%	4.83%	6/8/1990	8.31%
6/20/2007	5.2413	5.24%	4.83%	6/11/1990	8.31%
6/19/2007	5.1952	5.20%	4.82%	6/12/1990	8.31%
6/18/2007	5.2523	5.25%	4.82%	6/13/1990	8.31%
6/15/2007	5.259	5.26%	4.82%	6/14/1990	8.31%
6/14/2007	5.3012	5.30%	4.82%	6/15/1990	8.32%
6/13/2007	5.2789	5.28%	4.82%	6/18/1990	8.32%
6/12/2007	5.4019	5.40%	4.82%	6/19/1990	8.32%
6/11/2007	5.2555	5.26%	4.81%	6/20/1990	8.32%
6/8/2007	5.207	5.21%	4.81%	6/21/1990	8.32%
6/7/2007	5.23	5.23%	4.81%	6/22/1990	8.32%
6/6/2007	5.0806	5.08%	4.81%	6/25/1990	8.33%
6/5/2007	5.087	5.09%	4.81%	6/26/1990	8.33%
6/4/2007	5.0224	5.02%	4.81%	6/27/1990	8.33%
6/1/2007	5.0572	5.06%	4.81%	6/28/1990	8.33%
5/31/2007	5.0098	5.01%	4.81%	6/29/1990	8.33%

5/30/2007	5.0014	5.00%	4.81%	7/2/1990	8.34%
5/29/2007	5.0171	5.02%	4.81%	7/3/1990	8.34%
5/28/2007	5.0024	5.00%	4.80%	7/4/1990	8.34%
5/25/2007	5.0024	5.00%	4.80%	7/5/1990	8.34%
5/24/2007	4.9898	4.99%	4.80%	7/6/1990	8.34%
5/23/2007	5.0034	5.00%	4.80%	7/9/1990	8.34%
5/22/2007	4.9804	4.98%	4.80%	7/10/1990	8.34%
5/21/2007	4.937	4.94%	4.80%	7/11/1990	8.34%
5/18/2007	4.9576	4.96%	4.81%	7/12/1990	8.35%
5/17/2007	4.9133	4.91%	4.81%	7/13/1990	8.35%
5/16/2007	4.8787	4.88%	4.81%	7/16/1990	8.35%
5/15/2007	4.8746	4.87%	4.81%	7/17/1990	8.35%
5/14/2007	4.8675	4.87%	4.81%	7/18/1990	8.35%
5/11/2007	4.8493	4.85%	4.81%	7/19/1990	8.36%
5/10/2007	4.8221	4.82%	4.81%	7/20/1990	8.36%
5/9/2007	4.8362	4.84%	4.81%	7/23/1990	8.36%
5/8/2007	4.8021	4.80%	4.81%	7/24/1990	8.36%
5/7/2007	4.7822	4.78%	4.81%	7/25/1990	8.37%
5/4/2007	4.8051	4.81%	4.82%	7/26/1990	8.37%
5/3/2007	4.8382	4.84%	4.82%	7/27/1990	8.37%
5/2/2007	4.8151	4.82%	4.82%	7/30/1990	8.37%
5/1/2007	4.8151	4.82%	4.82%	7/31/1990	8.38%
4/30/2007	4.8131	4.81%	4.82%	8/1/1990	8.38%
4/27/2007	4.8806	4.88%	4.82%	8/2/1990	8.38%
4/26/2007	4.8806	4.88%	4.82%	8/3/1990	8.38%
4/25/2007	4.8331	4.83%	4.82%	8/6/1990	8.39%
4/24/2007	4.8061	4.81%	4.83%	8/7/1990	8.39%
4/23/2007	4.8221	4.82%	4.83%	8/8/1990	8.40%
4/20/2007	4.8452	4.85%	4.83%	8/9/1990	8.40%
4/19/2007	4.8331	4.83%	4.83%	8/10/1990	8.41%
4/18/2007	4.8151	4.82%	4.83%	8/13/1990	8.41%
4/17/2007	4.8432	4.84%	4.83%	8/14/1990	8.42%
4/16/2007	4.8897	4.89%	4.83%	8/15/1990	8.42%
4/13/2007	4.9296	4.93%	4.84%	8/16/1990	8.43%
4/12/2007	4.907	4.91%	4.84%	8/17/1990	8.43%
4/11/2007	4.908	4.91%	4.84%	8/20/1990	8.44%
4/10/2007	4.904	4.90%	4.84%	8/21/1990	8.44%
4/9/2007	4.9183	4.92%	4.84%	8/22/1990	8.45%
4/6/2007	4.9203	4.92%	4.84%	8/23/1990	8.45%
4/5/2007	4.8745	4.87%	4.84%	8/24/1990	8.46%
4/4/2007	4.8422	4.84%	4.85%	8/27/1990	8.47%
4/3/2007	4.8482	4.85%	4.85%	8/28/1990	8.47%
4/2/2007	4.8361	4.84%	4.85%	8/29/1990	8.48%
3/30/2007	4.8432	4.84%	4.85%	8/30/1990	8.48%
3/29/2007	4.8432	4.84%	4.85%	8/31/1990	8.49%
3/28/2007	4.8311	4.83%	4.86%	9/3/1990	8.49%
3/27/2007	4.7982	4.80%	4.86%	9/4/1990	8.50%

3/26/2007	4.8002	4.80%	4.86%	9/5/1990	8.50%
3/23/2007	4.8022	4.80%	4.86%	9/6/1990	8.51%
3/22/2007	4.7744	4.77%	4.86%	9/7/1990	8.51%
3/21/2007	4.7203	4.72%	4.87%	9/10/1990	8.52%
3/20/2007	4.7115	4.71%	4.87%	9/11/1990	8.52%
3/19/2007	4.7135	4.71%	4.87%	9/12/1990	8.53%
3/16/2007	4.6931	4.69%	4.87%	9/13/1990	8.54%
3/15/2007	4.695	4.70%	4.87%	9/14/1990	8.54%
3/14/2007	4.6989	4.70%	4.87%	9/17/1990	8.55%
3/13/2007	4.6564	4.66%	4.88%	9/18/1990	8.55%
3/12/2007	4.697	4.70%	4.88%	9/19/1990	8.56%
3/9/2007	4.7214	4.72%	4.88%	9/20/1990	8.56%
3/8/2007	4.6545	4.65%	4.88%	9/21/1990	8.57%
3/7/2007	4.6286	4.63%	4.89%	9/24/1990	8.58%
3/6/2007	4.6584	4.66%	4.89%	9/25/1990	8.58%
3/5/2007	4.6344	4.63%	4.89%	9/26/1990	8.59%
3/2/2007	4.6382	4.64%	4.89%	9/27/1990	8.60%
3/1/2007	4.6758	4.68%	4.90%	9/28/1990	8.60%
2/28/2007	4.6806	4.68%	4.90%	10/1/1990	8.61%
2/27/2007	4.6316	4.63%	4.90%	10/2/1990	8.61%
2/26/2007	4.7303	4.73%	4.90%	10/3/1990	8.62%
2/23/2007	4.7765	4.78%	4.91%	10/4/1990	8.62%
2/22/2007	4.8293	4.83%	4.91%	10/5/1990	8.62%
2/21/2007	4.7904	4.79%	4.91%	10/8/1990	8.63%
2/20/2007	4.7766	4.78%	4.91%	10/9/1990	8.63%
2/19/2007	4.7874	4.79%	4.91%	10/10/1990	8.64%
2/16/2007	4.7875	4.79%	4.92%	10/11/1990	8.64%
2/15/2007	4.8054	4.81%	4.92%	10/12/1990	8.65%
2/14/2007	4.8333	4.83%	4.92%	10/15/1990	8.65%
2/13/2007	4.8989	4.90%	4.92%	10/16/1990	8.66%
2/12/2007	4.8857	4.89%	4.92%	10/17/1990	8.66%
2/9/2007	4.8635	4.86%	4.93%	10/18/1990	8.66%
2/8/2007	4.8396	4.84%	4.93%	10/19/1990	8.67%
2/7/2007	4.8521	4.85%	4.93%	10/22/1990	8.67%
2/6/2007	4.8679	4.87%	4.93%	10/23/1990	8.67%
2/5/2007	4.9071	4.91%	4.93%	10/24/1990	8.67%
2/2/2007	4.922	4.92%	4.93%	10/25/1990	8.68%
2/1/2007	4.9294	4.93%	4.94%	10/26/1990	8.68%
1/31/2007	4.9069	4.91%	4.94%	10/29/1990	8.68%
1/30/2007	4.9777	4.98%	4.94%	10/30/1990	8.68%
1/29/2007	4.995	5.00%	4.94%	10/31/1990	8.69%
1/26/2007	4.9722	4.97%	4.94%	11/1/1990	8.69%
1/25/2007	4.9667	4.97%	4.94%	11/2/1990	8.69%
1/24/2007	4.9099	4.91%	4.94%	11/5/1990	8.69%
1/23/2007	4.9057	4.91%	4.94%	11/6/1990	8.69%
1/22/2007	4.8476	4.85%	4.94%	11/7/1990	8.69%
1/19/2007	4.8623	4.86%	4.94%	11/8/1990	8.69%

1/18/2007	4.8401	4.84%	4.94%	11/9/1990	8.69%
1/17/2007	4.8706	4.87%	4.95%	11/12/1990	8.69%
1/16/2007	4.8401	4.84%	4.95%	11/13/1990	8.69%
1/15/2007	4.86	4.86%	4.95%	11/14/1990	8.69%
1/12/2007	4.86	4.86%	4.95%	11/15/1990	8.69%
1/11/2007	4.8181	4.82%	4.95%	11/16/1990	8.69%
1/10/2007	4.7745	4.77%	4.95%	11/19/1990	8.69%
1/9/2007	4.7375	4.74%	4.95%	11/20/1990	8.69%
1/8/2007	4.7334	4.73%	4.95%	11/21/1990	8.69%
1/5/2007	4.7385	4.74%	4.95%	11/22/1990	8.69%
1/4/2007	4.7079	4.71%	4.95%	11/23/1990	8.69%
1/3/2007	4.7631	4.76%	4.95%	11/26/1990	8.69%
1/2/2007	4.7847	4.78%	4.95%	11/27/1990	8.69%
1/1/2007	4.8096	4.81%	4.95%	11/28/1990	8.69%
12/29/2006	4.8095	4.81%	4.95%	11/29/1990	8.69%
12/28/2006	4.8064	4.81%	4.95%	11/30/1990	8.69%
12/27/2006	4.7763	4.78%	4.95%	12/3/1990	8.69%
12/26/2006	4.7312	4.73%	4.95%	12/4/1990	8.69%
12/25/2006	4.7578	4.76%	4.95%	12/5/1990	8.69%
12/22/2006	4.7578	4.76%	4.95%	12/6/1990	8.68%
12/21/2006	4.6875	4.69%	4.95%	12/7/1990	8.68%
12/20/2006	4.728	4.73%	4.95%	12/10/1990	8.68%
12/19/2006	4.7189	4.72%	4.95%	12/11/1990	8.68%
12/18/2006	4.7057	4.71%	4.95%	12/12/1990	8.68%
12/15/2006	4.7138	4.71%	4.95%	12/13/1990	8.67%
12/14/2006	4.7137	4.71%	4.95%	12/14/1990	8.67%
12/13/2006	4.6965	4.70%	4.95%	12/17/1990	8.67%
12/12/2006	4.6064	4.61%	4.95%	12/18/1990	8.67%
12/11/2006	4.6242	4.62%	4.95%	12/19/1990	8.66%
12/8/2006	4.6532	4.65%	4.95%	12/20/1990	8.66%
12/7/2006	4.6024	4.60%	4.95%	12/21/1990	8.66%
12/6/2006	4.5994	4.60%	4.95%	12/24/1990	8.66%
12/5/2006	4.5727	4.57%	4.95%	12/25/1990	8.66%
12/4/2006	4.5404	4.54%	4.95%	12/26/1990	8.66%
12/1/2006	4.5463	4.55%	4.95%	12/27/1990	8.66%
11/30/2006	4.5619	4.56%	4.95%	12/28/1990	8.66%
11/29/2006	4.6142	4.61%	4.95%	12/31/1990	8.65%
11/28/2006	4.5914	4.59%	4.95%	1/3/1991	8.65%
11/27/2006	4.6112	4.61%	4.95%	1/4/1991	8.65%
11/24/2006	4.6311	4.63%	4.95%	1/7/1991	8.65%
11/23/2006	4.646	4.65%	4.95%	1/8/1991	8.65%
11/22/2006	4.646	4.65%	4.95%	1/9/1991	8.65%
11/21/2006	4.657	4.66%	4.95%	1/10/1991	8.65%
11/20/2006	4.6791	4.68%	4.95%	1/11/1991	8.65%
11/17/2006	4.6881	4.69%	4.95%	1/14/1991	8.65%
11/16/2006	4.7419	4.74%	4.95%	1/15/1991	8.64%
11/15/2006	4.7002	4.70%	4.95%	1/16/1991	8.64%

11/14/2006	4.656	4.66%	4.95%	1/17/1991	8.64%
11/13/2006	4.7053	4.71%	4.95%	1/18/1991	8.64%
11/10/2006	4.6972	4.70%	4.95%	1/21/1991	8.64%
11/9/2006	4.7296	4.73%	4.95%	1/22/1991	8.64%
11/8/2006	4.7276	4.73%	4.95%	1/23/1991	8.63%
11/7/2006	4.7551	4.76%	4.95%	1/24/1991	8.63%
11/6/2006	4.7839	4.78%	4.95%	1/25/1991	8.63%
11/3/2006	4.8086	4.81%	4.95%	1/28/1991	8.63%
11/2/2006	4.7153	4.72%	4.95%	1/29/1991	8.62%
11/1/2006	4.684	4.68%	4.95%	1/30/1991	8.62%
10/31/2006	4.7153	4.72%	4.95%	1/31/1991	8.61%
10/30/2006	4.7827	4.78%	4.95%	2/1/1991	8.61%
10/27/2006	4.793	4.79%	4.94%	2/4/1991	8.60%
10/26/2006	4.8366	4.84%	4.94%	2/5/1991	8.60%
10/25/2006	4.8816	4.88%	4.94%	2/6/1991	8.59%
10/24/2006	4.941	4.94%	4.94%	2/7/1991	8.59%
10/23/2006	4.957	4.96%	4.94%	2/8/1991	8.58%
10/20/2006	4.908	4.91%	4.93%	2/11/1991	8.58%
10/19/2006	4.9101	4.91%	4.93%	2/12/1991	8.58%
10/18/2006	4.8836	4.88%	4.93%	2/13/1991	8.57%
10/17/2006	4.8984	4.90%	4.93%	2/14/1991	8.57%
10/16/2006	4.9079	4.91%	4.93%	2/15/1991	8.56%
10/13/2006	4.9334	4.93%	4.93%	2/18/1991	8.56%
10/12/2006	4.9057	4.91%	4.92%	2/19/1991	8.55%
10/11/2006	4.9057	4.91%	4.92%	2/20/1991	8.55%
10/10/2006	4.8835	4.88%	4.92%	2/21/1991	8.55%
10/9/2006	4.8343	4.83%	4.92%	2/22/1991	8.55%
10/6/2006	4.8343	4.83%	4.92%	2/25/1991	8.54%
10/5/2006	4.7589	4.76%	4.92%	2/26/1991	8.54%
10/4/2006	4.7202	4.72%	4.92%	2/27/1991	8.54%
10/3/2006	4.7538	4.75%	4.91%	2/28/1991	8.54%
10/2/2006	4.7476	4.75%	4.91%	3/1/1991	8.53%
9/29/2006	4.7619	4.76%	4.91%	3/4/1991	8.53%
9/28/2006	4.7548	4.75%	4.91%	3/5/1991	8.53%
9/27/2006	4.7374	4.74%	4.91%	3/6/1991	8.53%
9/26/2006	4.7141	4.71%	4.91%	3/7/1991	8.53%
9/25/2006	4.6878	4.69%	4.91%	3/8/1991	8.52%
9/22/2006	4.7343	4.73%	4.91%	3/11/1991	8.52%
9/21/2006	4.7721	4.77%	4.91%	3/12/1991	8.52%
9/20/2006	4.8477	4.85%	4.91%	3/13/1991	8.52%
9/19/2006	4.8581	4.86%	4.91%	3/14/1991	8.52%
9/18/2006	4.9234	4.92%	4.91%	3/15/1991	8.52%
9/15/2006	4.9096	4.91%	4.91%	3/18/1991	8.52%
9/14/2006	4.916	4.92%	4.91%	3/19/1991	8.52%
9/13/2006	4.8927	4.89%	4.90%	3/20/1991	8.52%
9/12/2006	4.9032	4.90%	4.90%	3/21/1991	8.52%
9/11/2006	4.9404	4.94%	4.90%	3/22/1991	8.52%

9/8/2006	4.918	4.92%	4.90%	3/25/1991	8.52%
9/7/2006	4.9339	4.93%	4.90%	3/26/1991	8.52%
9/6/2006	4.9488	4.95%	4.90%	3/27/1991	8.51%
9/5/2006	4.9297	4.93%	4.90%	3/28/1991	8.51%
9/4/2006	4.8716	4.87%	4.90%	3/29/1991	8.51%
9/1/2006	4.8716	4.87%	4.90%	4/1/1991	8.51%
8/31/2006	4.8768	4.88%	4.89%	4/2/1991	8.51%
8/30/2006	4.9042	4.90%	4.89%	4/3/1991	8.51%
8/29/2006	4.9232	4.92%	4.89%	4/4/1991	8.51%
8/28/2006	4.9296	4.93%	4.89%	4/5/1991	8.50%
8/25/2006	4.9243	4.92%	4.89%	4/8/1991	8.50%
8/24/2006	4.938	4.94%	4.89%	4/9/1991	8.50%
8/23/2006	4.9455	4.95%	4.89%	4/10/1991	8.50%
8/22/2006	4.9433	4.94%	4.89%	4/11/1991	8.50%
8/21/2006	4.9572	4.96%	4.89%	4/12/1991	8.50%
8/18/2006	4.9786	4.98%	4.88%	4/15/1991	8.50%
8/17/2006	4.998	5.00%	4.88%	4/16/1991	8.50%
8/16/2006	4.9915	4.99%	4.88%	4/17/1991	8.49%
8/15/2006	5.0479	5.05%	4.88%	4/18/1991	8.49%
8/14/2006	5.1127	5.11%	4.88%	4/19/1991	8.49%
8/11/2006	5.0939	5.09%	4.88%	4/22/1991	8.49%
8/10/2006	5.0729	5.07%	4.88%	4/23/1991	8.49%
8/9/2006	5.0488	5.05%	4.88%	4/24/1991	8.49%
8/8/2006	5.0194	5.02%	4.87%	4/25/1991	8.49%
8/7/2006	5.001	5.00%	4.87%	4/26/1991	8.49%
8/4/2006	4.988	4.99%	4.87%	4/29/1991	8.48%
8/3/2006	5.0442	5.04%	4.87%	4/30/1991	8.48%
8/2/2006	5.0529	5.05%	4.87%	5/1/1991	8.48%
8/1/2006	5.0605	5.06%	4.87%	5/2/1991	8.48%
7/31/2006	5.0649	5.06%	4.87%	5/3/1991	8.48%
7/28/2006	5.0703	5.07%	4.86%	5/6/1991	8.47%
7/27/2006	5.1043	5.10%	4.86%	5/7/1991	8.47%
7/26/2006	5.0943	5.09%	4.86%	5/8/1991	8.47%
7/25/2006	5.1219	5.12%	4.86%	5/9/1991	8.47%
7/24/2006	5.102	5.10%	4.86%	5/10/1991	8.47%
7/21/2006	5.0931	5.09%	4.85%	5/13/1991	8.47%
7/20/2006	5.082	5.08%	4.85%	5/14/1991	8.47%
7/19/2006	5.0985	5.10%	4.85%	5/15/1991	8.47%
7/18/2006	5.1651	5.17%	4.85%	5/16/1991	8.46%
7/17/2006	5.0984	5.10%	4.84%	5/17/1991	8.46%
7/14/2006	5.115	5.12%	4.84%	5/20/1991	8.46%
7/13/2006	5.1127	5.11%	4.84%	5/21/1991	8.46%
7/12/2006	5.137	5.14%	4.84%	5/22/1991	8.45%
7/11/2006	5.1459	5.15%	4.83%	5/23/1991	8.45%
7/10/2006	5.1705	5.17%	4.83%	5/24/1991	8.45%
7/7/2006	5.1738	5.17%	4.83%	5/27/1991	8.45%
7/6/2006	5.2222	5.22%	4.83%	5/28/1991	8.44%

7/5/2006	5.2666	5.27%	4.82%	5/29/1991	8.44%
7/4/2006	5.1995	5.20%	4.82%	5/30/1991	8.44%
7/3/2006	5.1995	5.20%	4.81%	5/31/1991	8.43%
6/30/2006	5.1859	5.19%	4.81%	6/3/1991	8.43%
6/29/2006	5.2469	5.25%	4.81%	6/4/1991	8.42%
6/28/2006	5.2812	5.28%	4.80%	6/5/1991	8.42%
6/27/2006	5.232	5.23%	4.80%	6/6/1991	8.42%
6/26/2006	5.2719	5.27%	4.80%	6/7/1991	8.42%
6/23/2006	5.2536	5.25%	4.79%	6/10/1991	8.41%
6/22/2006	5.2432	5.24%	4.79%	6/11/1991	8.41%
6/21/2006	5.1922	5.19%	4.79%	6/12/1991	8.41%
6/20/2006	5.1911	5.19%	4.78%	6/13/1991	8.41%
6/19/2006	5.1742	5.17%	4.78%	6/14/1991	8.40%
6/16/2006	5.1686	5.17%	4.77%	6/17/1991	8.40%
6/15/2006	5.1361	5.14%	4.77%	6/18/1991	8.40%
6/14/2006	5.0919	5.09%	4.77%	6/19/1991	8.40%
6/13/2006	5.0145	5.01%	4.76%	6/20/1991	8.39%
6/12/2006	5.0231	5.02%	4.76%	6/21/1991	8.39%
6/9/2006	5.0199	5.02%	4.76%	6/24/1991	8.39%
6/8/2006	5.0632	5.06%	4.75%	6/25/1991	8.39%
6/7/2006	5.0873	5.09%	4.75%	6/26/1991	8.38%
6/6/2006	5.0763	5.08%	4.74%	6/27/1991	8.38%
6/5/2006	5.106	5.11%	4.74%	6/28/1991	8.38%
6/2/2006	5.0949	5.09%	4.74%	7/1/1991	8.38%
6/1/2006	5.1927	5.19%	4.73%	7/2/1991	8.37%
5/31/2006	5.2277	5.23%	4.73%	7/3/1991	8.37%
5/30/2006	5.1837	5.18%	4.73%	7/4/1991	8.36%
5/29/2006	5.1545	5.15%	4.72%	7/5/1991	8.36%
5/26/2006	5.1545	5.15%	4.72%	7/8/1991	8.36%
5/25/2006	5.1689	5.17%	4.71%	7/9/1991	8.36%
5/24/2006	5.1333	5.13%	4.71%	7/10/1991	8.36%
5/23/2006	5.1155	5.12%	4.71%	7/11/1991	8.35%
5/22/2006	5.131	5.13%	4.70%	7/12/1991	8.35%
5/19/2006	5.1376	5.14%	4.70%	7/15/1991	8.35%
5/18/2006	5.1654	5.17%	4.70%	7/16/1991	8.35%
5/17/2006	5.2659	5.27%	4.69%	7/17/1991	8.35%
5/16/2006	5.2091	5.21%	4.69%	7/18/1991	8.34%
5/15/2006	5.2716	5.27%	4.69%	7/19/1991	8.34%
5/12/2006	5.3106	5.31%	4.68%	7/22/1991	8.34%
5/11/2006	5.2304	5.23%	4.68%	7/23/1991	8.34%
5/10/2006	5.192	5.19%	4.68%	7/24/1991	8.33%
5/9/2006	5.1976	5.20%	4.67%	7/25/1991	8.33%
5/8/2006	5.1819	5.18%	4.67%	7/26/1991	8.33%
5/5/2006	5.1875	5.19%	4.67%	7/29/1991	8.33%
5/4/2006	5.2382	5.24%	4.66%	7/30/1991	8.32%
5/3/2006	5.2336	5.23%	4.66%	7/31/1991	8.32%
5/2/2006	5.2076	5.21%	4.65%	8/1/1991	8.32%

5/1/2006	5.2268	5.23%	4.65%	8/2/1991	8.32%
4/28/2006	5.1615	5.16%	4.65%	8/5/1991	8.31%
4/27/2006	5.1704	5.17%	4.64%	8/6/1991	8.31%
4/26/2006	5.1827	5.18%	4.64%	8/7/1991	8.31%
4/25/2006	5.1547	5.15%	4.64%	8/8/1991	8.31%
4/24/2006	5.0578	5.06%	4.63%	8/9/1991	8.30%
4/21/2006	5.0928	5.09%	4.63%	8/12/1991	8.30%
4/20/2006	5.1379	5.14%	4.63%	8/13/1991	8.30%
4/19/2006	5.1202	5.12%	4.62%	8/14/1991	8.29%
4/18/2006	5.0762	5.08%	4.62%	8/15/1991	8.29%
4/17/2006	5.0795	5.08%	4.61%	8/16/1991	8.29%
4/14/2006	5.1124	5.11%	4.61%	8/19/1991	8.29%
4/13/2006	5.1124	5.11%	4.61%	8/20/1991	8.28%
4/12/2006	5.0575	5.06%	4.60%	8/21/1991	8.28%
4/11/2006	4.9959	5.00%	4.60%	8/22/1991	8.28%
4/10/2006	5.025	5.03%	4.60%	8/23/1991	8.28%
4/7/2006	5.0553	5.06%	4.59%	8/26/1991	8.27%
4/6/2006	4.9734	4.97%	4.59%	8/27/1991	8.27%
4/5/2006	4.9024	4.90%	4.58%	8/28/1991	8.27%
4/4/2006	4.9087	4.91%	4.58%	8/29/1991	8.27%
4/3/2006	4.894	4.89%	4.58%	8/30/1991	8.27%
3/31/2006	4.8898	4.89%	4.57%	9/2/1991	8.27%
3/30/2006	4.896	4.90%	4.57%	9/3/1991	8.26%
3/29/2006	4.8398	4.84%	4.57%	9/4/1991	8.26%
3/28/2006	4.7955	4.80%	4.57%	9/5/1991	8.26%
3/27/2006	4.7274	4.73%	4.56%	9/6/1991	8.26%
3/24/2006	4.6893	4.69%	4.56%	9/9/1991	8.25%
3/23/2006	4.7537	4.75%	4.56%	9/10/1991	8.25%
3/22/2006	4.7224	4.72%	4.56%	9/11/1991	8.25%
3/21/2006	4.7446	4.74%	4.56%	9/12/1991	8.25%
3/20/2006	4.6993	4.70%	4.55%	9/13/1991	8.25%
3/17/2006	4.7173	4.72%	4.55%	9/16/1991	8.24%
3/16/2006	4.6923	4.69%	4.55%	9/17/1991	8.24%
3/15/2006	4.7496	4.75%	4.55%	9/18/1991	8.24%
3/14/2006	4.6993	4.70%	4.55%	9/19/1991	8.24%
3/13/2006	4.7597	4.76%	4.54%	9/20/1991	8.24%
3/10/2006	4.7476	4.75%	4.54%	9/23/1991	8.24%
3/9/2006	4.7173	4.72%	4.54%	9/24/1991	8.24%
3/8/2006	4.7153	4.72%	4.54%	9/25/1991	8.24%
3/7/2006	4.7093	4.71%	4.53%	9/26/1991	8.24%
3/6/2006	4.7354	4.74%	4.53%	9/27/1991	8.23%
3/3/2006	4.6594	4.66%	4.53%	9/30/1991	8.23%
3/2/2006	4.6111	4.61%	4.53%	10/1/1991	8.23%
3/1/2006	4.5585	4.56%	4.53%	10/2/1991	8.23%
2/28/2006	4.5075	4.51%	4.53%	10/3/1991	8.22%
2/27/2006	4.5498	4.55%	4.53%	10/4/1991	8.22%
2/24/2006	4.5258	4.53%	4.53%	10/7/1991	8.22%

2/23/2006	4.5009	4.50%	4.53%	10/8/1991	8.22%
2/22/2006	4.4799	4.48%	4.53%	10/9/1991	8.22%
2/21/2006	4.5306	4.53%	4.53%	10/10/1991	8.21%
2/20/2006	4.5057	4.51%	4.53%	10/11/1991	8.21%
2/17/2006	4.5057	4.51%	4.53%	10/14/1991	8.21%
2/16/2006	4.5654	4.57%	4.53%	10/15/1991	8.21%
2/15/2006	4.5722	4.57%	4.53%	10/16/1991	8.20%
2/14/2006	4.5887	4.59%	4.53%	10/17/1991	8.20%
2/13/2006	4.5557	4.56%	4.53%	10/18/1991	8.20%
2/10/2006	4.5518	4.55%	4.53%	10/21/1991	8.20%
2/9/2006	4.6508	4.65%	4.53%	10/22/1991	8.20%
2/8/2006	4.6746	4.67%	4.53%	10/23/1991	8.20%
2/7/2006	4.6538	4.65%	4.52%	10/24/1991	8.20%
2/6/2006	4.6222	4.62%	4.52%	10/25/1991	8.20%
2/3/2006	4.6242	4.62%	4.52%	10/28/1991	8.19%
2/2/2006	4.6947	4.69%	4.52%	10/29/1991	8.19%
2/1/2006	4.7058	4.71%	4.52%	10/30/1991	8.19%
1/31/2006	4.6768	4.68%	4.52%	10/31/1991	8.19%
1/30/2006	4.7018	4.70%	4.52%	11/1/1991	8.19%
1/27/2006	4.6918	4.69%	4.52%	11/4/1991	8.19%
1/26/2006	4.6939	4.69%	4.52%	11/5/1991	8.19%
1/25/2006	4.6552	4.66%	4.52%	11/6/1991	8.19%
1/24/2006	4.5717	4.57%	4.52%	11/7/1991	8.18%
1/23/2006	4.5301	4.53%	4.52%	11/8/1991	8.18%
1/20/2006	4.5214	4.52%	4.52%	11/11/1991	8.18%
1/19/2006	4.5467	4.55%	4.52%	11/12/1991	8.18%
1/18/2006	4.511	4.51%	4.52%	11/13/1991	8.18%
1/17/2006	4.5024	4.50%	4.52%	11/14/1991	8.18%
1/16/2006	4.5284	4.53%	4.52%	11/15/1991	8.18%
1/13/2006	4.5284	4.53%	4.52%	11/18/1991	8.18%
1/12/2006	4.5839	4.58%	4.53%	11/19/1991	8.18%
1/11/2006	4.6319	4.63%	4.53%	11/20/1991	8.18%
1/10/2006	4.6113	4.61%	4.53%	11/21/1991	8.18%
1/9/2006	4.5509	4.55%	4.53%	11/22/1991	8.18%
1/6/2006	4.5607	4.56%	4.53%	11/25/1991	8.18%
1/5/2006	4.5453	4.55%	4.53%	11/26/1991	8.18%
1/4/2006	4.5366	4.54%	4.53%	11/27/1991	8.18%
1/3/2006	4.5463	4.55%	4.53%	11/28/1991	8.18%
1/2/2006	4.5347	4.53%	4.53%	11/29/1991	8.18%
12/30/2005	4.5348	4.53%	4.53%	12/2/1991	8.17%
12/29/2005	4.5128	4.51%	4.54%	12/3/1991	8.17%
12/28/2005	4.5311	4.53%	4.54%	12/4/1991	8.17%
12/27/2005	4.5042	4.50%	4.54%	12/5/1991	8.17%
12/23/2005	4.5447	4.54%	4.54%	12/6/1991	8.17%
12/22/2005	4.6061	4.61%	4.54%	12/9/1991	8.17%
12/21/2005	4.6751	4.68%	4.54%	12/10/1991	8.16%
12/20/2005	4.6534	4.65%	4.54%	12/11/1991	8.16%

12/19/2005	4.6386	4.64%	4.55%	12/12/1991	8.16%
12/16/2005	4.6426	4.64%	4.55%	12/13/1991	8.16%
12/15/2005	4.6723	4.67%	4.55%	12/16/1991	8.15%
12/14/2005	4.6615	4.66%	4.55%	12/17/1991	8.15%
12/13/2005	4.7242	4.72%	4.55%	12/18/1991	8.15%
12/12/2005	4.7453	4.75%	4.55%	12/19/1991	8.15%
12/9/2005	4.7273	4.73%	4.55%	12/20/1991	8.14%
12/8/2005	4.6676	4.67%	4.55%	12/23/1991	8.14%
12/7/2005	4.7134	4.71%	4.55%	12/24/1991	8.13%
12/6/2005	4.6776	4.68%	4.55%	12/25/1991	8.13%
12/5/2005	4.7606	4.76%	4.55%	12/26/1991	8.13%
12/2/2005	4.7135	4.71%	4.55%	12/27/1991	8.12%
12/1/2005	4.7146	4.71%	4.55%	12/30/1991	8.12%
11/30/2005	4.6927	4.69%	4.55%	12/31/1991	8.11%
11/29/2005	4.6908	4.69%	4.55%	1/2/1992	8.11%
11/28/2005	4.6188	4.62%	4.55%	1/3/1992	8.11%
11/25/2005	4.6581	4.66%	4.55%	1/6/1992	8.10%
11/24/2005	4.6998	4.70%	4.55%	1/7/1992	8.10%
11/23/2005	4.7009	4.70%	4.55%	1/8/1992	8.09%
11/22/2005	4.6544	4.65%	4.55%	1/9/1992	8.09%
11/21/2005	4.6594	4.66%	4.54%	1/10/1992	8.09%
11/18/2005	4.6831	4.68%	4.54%	1/13/1992	8.08%
11/17/2005	4.6487	4.65%	4.54%	1/14/1992	8.08%
11/16/2005	4.6635	4.66%	4.54%	1/15/1992	8.08%
11/15/2005	4.7482	4.75%	4.54%	1/16/1992	8.07%
11/14/2005	4.7956	4.80%	4.54%	1/17/1992	8.07%
11/11/2005	4.7412	4.74%	4.54%	1/20/1992	8.07%
11/10/2005	4.7372	4.74%	4.53%	1/21/1992	8.06%
11/9/2005	4.8375	4.84%	4.53%	1/22/1992	8.06%
11/8/2005	4.7585	4.76%	4.53%	1/23/1992	8.06%
11/7/2005	4.8152	4.82%	4.53%	1/24/1992	8.06%
11/4/2005	4.8571	4.86%	4.53%	1/27/1992	8.05%
11/3/2005	4.8438	4.84%	4.53%	1/28/1992	8.05%
11/2/2005	4.7991	4.80%	4.53%	1/29/1992	8.05%
11/1/2005	4.7587	4.76%	4.53%	1/30/1992	8.05%
10/31/2005	4.7537	4.75%	4.53%	1/31/1992	8.04%
10/28/2005	4.7719	4.77%	4.53%	2/3/1992	8.04%
10/27/2005	4.7659	4.77%	4.53%	2/4/1992	8.04%
10/26/2005	4.7932	4.79%	4.53%	2/5/1992	8.04%
10/25/2005	4.7349	4.73%	4.53%	2/6/1992	8.04%
10/24/2005	4.6614	4.66%	4.52%	2/7/1992	8.03%
10/21/2005	4.6017	4.60%	4.53%	2/10/1992	8.03%
10/20/2005	4.6616	4.66%	4.53%	2/11/1992	8.03%
10/19/2005	4.6893	4.69%	4.53%	2/12/1992	8.03%
10/18/2005	4.6933	4.69%	4.53%	2/13/1992	8.03%
10/17/2005	4.7142	4.71%	4.53%	2/14/1992	8.02%
10/14/2005	4.7023	4.70%	4.53%	2/17/1992	8.02%

10/13/2005	4.6915	4.69%	4.53%	2/18/1992	8.02%
10/12/2005	4.6599	4.66%	4.53%	2/19/1992	8.02%
10/11/2005	4.5973	4.60%	4.53%	2/20/1992	8.02%
10/10/2005	4.5673	4.57%	4.53%	2/21/1992	8.01%
10/7/2005	4.5645	4.56%	4.53%	2/24/1992	8.01%
10/6/2005	4.6122	4.61%	4.53%	2/25/1992	8.01%
10/5/2005	4.5647	4.56%	4.53%	2/26/1992	8.01%
10/4/2005	4.6006	4.60%	4.54%	2/27/1992	8.01%
10/3/2005	4.6211	4.62%	4.54%	2/28/1992	8.00%
9/30/2005	4.5668	4.57%	4.54%	3/2/1992	8.00%
9/29/2005	4.5448	4.54%	4.54%	3/3/1992	8.00%
9/28/2005	4.5027	4.50%	4.54%	3/4/1992	8.00%
9/27/2005	4.5381	4.54%	4.54%	3/5/1992	8.00%
9/26/2005	4.5593	4.56%	4.55%	3/6/1992	8.00%
9/23/2005	4.5191	4.52%	4.55%	3/9/1992	7.99%
9/22/2005	4.4622	4.46%	4.55%	3/10/1992	7.99%
9/21/2005	4.4566	4.46%	4.55%	3/11/1992	7.99%
9/20/2005	4.5241	4.52%	4.55%	3/12/1992	7.99%
9/19/2005	4.5462	4.55%	4.55%	3/13/1992	7.99%
9/16/2005	4.5646	4.56%	4.55%	3/16/1992	7.98%
9/15/2005	4.5148	4.51%	4.56%	3/17/1992	7.98%
9/14/2005	4.4485	4.45%	4.56%	3/18/1992	7.98%
9/13/2005	4.4148	4.41%	4.56%	3/19/1992	7.98%
9/12/2005	4.4467	4.45%	4.56%	3/20/1992	7.97%
9/9/2005	4.399	4.40%	4.56%	3/23/1992	7.97%
9/8/2005	4.4319	4.43%	4.57%	3/24/1992	7.97%
9/7/2005	4.4217	4.42%	4.57%	3/25/1992	7.97%
9/6/2005	4.3584	4.36%	4.57%	3/26/1992	7.96%
9/5/2005	4.2969	4.30%	4.58%	3/27/1992	7.96%
9/2/2005	4.2961	4.30%	4.58%	3/30/1992	7.96%
9/1/2005	4.3101	4.31%	4.58%	3/31/1992	7.96%
8/31/2005	4.2537	4.25%	4.58%	4/1/1992	7.95%
8/30/2005	4.3111	4.31%	4.59%	4/2/1992	7.95%
8/29/2005	4.359	4.36%	4.59%	4/3/1992	7.95%
8/26/2005	4.372	4.37%	4.59%	4/6/1992	7.94%
8/25/2005	4.3648	4.36%	4.59%	4/7/1992	7.94%
8/24/2005	4.3889	4.39%	4.60%	4/8/1992	7.94%
8/23/2005	4.3983	4.40%	4.60%	4/9/1992	7.94%
8/22/2005	4.4273	4.43%	4.60%	4/10/1992	7.93%
8/19/2005	4.4189	4.42%	4.60%	4/13/1992	7.93%
8/18/2005	4.4182	4.42%	4.61%	4/14/1992	7.93%
8/17/2005	4.4755	4.48%	4.61%	4/15/1992	7.92%
8/16/2005	4.4183	4.42%	4.61%	4/16/1992	7.92%
8/15/2005	4.4804	4.48%	4.61%	4/17/1992	7.92%
8/12/2005	4.4484	4.45%	4.62%	4/20/1992	7.92%
8/11/2005	4.5138	4.51%	4.62%	4/21/1992	7.91%
8/10/2005	4.5771	4.58%	4.62%	4/22/1992	7.91%

8/9/2005	4.5723	4.57%	4.62%	4/23/1992	7.91%
8/8/2005	4.5994	4.60%	4.62%	4/24/1992	7.91%
8/5/2005	4.582	4.58%	4.62%	4/27/1992	7.91%
8/4/2005	4.5207	4.52%	4.62%	4/28/1992	7.90%
8/3/2005	4.4998	4.50%	4.63%	4/29/1992	7.90%
8/2/2005	4.5437	4.54%	4.63%	4/30/1992	7.90%
8/1/2005	4.5084	4.51%	4.63%	5/1/1992	7.90%
7/29/2005	4.4706	4.47%	4.63%	5/4/1992	7.90%
7/28/2005	4.3977	4.40%	4.63%	5/5/1992	7.89%
7/27/2005	4.4689	4.47%	4.63%	5/6/1992	7.89%
7/26/2005	4.4473	4.45%	4.64%	5/7/1992	7.89%
7/25/2005	4.4661	4.47%	4.64%	5/8/1992	7.89%
7/22/2005	4.4399	4.44%	4.64%	5/11/1992	7.89%
7/21/2005	4.5003	4.50%	4.64%	5/12/1992	7.88%
7/20/2005	4.3934	4.39%	4.64%	5/14/1992	7.88%
7/19/2005	4.4232	4.42%	4.64%	5/15/1992	7.88%
7/18/2005	4.4645	4.46%	4.65%	5/18/1992	7.88%
7/15/2005	4.3963	4.40%	4.65%	5/19/1992	7.88%
7/14/2005	4.4141	4.41%	4.65%	5/20/1992	7.87%
7/13/2005	4.3947	4.39%	4.65%	5/21/1992	7.87%
7/12/2005	4.3854	4.39%	4.66%	5/22/1992	7.87%
7/11/2005	4.3394	4.34%	4.66%	5/25/1992	7.87%
7/8/2005	4.3413	4.34%	4.66%	5/26/1992	7.87%
7/7/2005	4.3186	4.32%	4.67%	5/27/1992	7.87%
7/6/2005	4.3269	4.33%	4.67%	5/28/1992	7.87%
7/5/2005	4.3617	4.36%	4.67%	5/29/1992	7.87%
7/4/2005	4.2996	4.30%	4.67%	6/1/1992	7.87%
7/1/2005	4.2942	4.29%	4.68%	6/2/1992	7.86%
6/30/2005	4.1911	4.19%	4.68%	6/3/1992	7.86%
6/29/2005	4.26	4.26%	4.68%	6/4/1992	7.86%
6/28/2005	4.2475	4.25%	4.68%	6/5/1992	7.86%
6/27/2005	4.1912	4.19%	4.69%	6/8/1992	7.86%
6/24/2005	4.2207	4.22%	4.69%	6/9/1992	7.86%
6/23/2005	4.2523	4.25%	4.69%	6/10/1992	7.86%
6/22/2005	4.2424	4.24%	4.70%	6/11/1992	7.86%
6/21/2005	4.3249	4.32%	4.70%	6/12/1992	7.86%
6/20/2005	4.3874	4.39%	4.70%	6/15/1992	7.85%
6/17/2005	4.3607	4.36%	4.71%	6/16/1992	7.85%
6/16/2005	4.3673	4.37%	4.71%	6/17/1992	7.85%
6/15/2005	4.4016	4.40%	4.71%	6/18/1992	7.85%
6/14/2005	4.4137	4.41%	4.72%	6/19/1992	7.85%
6/13/2005	4.373	4.37%	4.72%	6/22/1992	7.85%
6/10/2005	4.3244	4.32%	4.72%	6/23/1992	7.85%
6/9/2005	4.2315	4.23%	4.73%	6/24/1992	7.85%
6/8/2005	4.22	4.22%	4.73%	6/25/1992	7.85%
6/7/2005	4.1907	4.19%	4.73%	6/26/1992	7.85%
6/6/2005	4.2434	4.24%	4.74%	6/29/1992	7.85%

6/3/2005	4.2812	4.28%	4.74%	6/30/1992	7.85%
6/2/2005	4.24	4.24%	4.74%	7/1/1992	7.85%
6/1/2005	4.2365	4.24%	4.75%	7/2/1992	7.85%
5/31/2005	4.3205	4.32%	4.75%	7/3/1992	7.84%
5/30/2005	4.4292	4.43%	4.76%	7/6/1992	7.84%
5/27/2005	4.4293	4.43%	4.76%	7/7/1992	7.84%
5/26/2005	4.4276	4.43%	4.76%	7/8/1992	7.84%
5/25/2005	4.4323	4.43%	4.76%	7/9/1992	7.84%
5/24/2005	4.3584	4.36%	4.77%	7/10/1992	7.84%
5/23/2005	4.3796	4.38%	4.77%	7/13/1992	7.84%
5/20/2005	4.4381	4.44%	4.77%	7/14/1992	7.84%
5/19/2005	4.4429	4.44%	4.78%	7/15/1992	7.84%
5/18/2005	4.4392	4.44%	4.78%	7/16/1992	7.84%
5/17/2005	4.4729	4.47%	4.78%	7/17/1992	7.83%
5/16/2005	4.4956	4.50%	4.79%	7/20/1992	7.83%
5/13/2005	4.4805	4.48%	4.79%	7/21/1992	7.83%
5/12/2005	4.5146	4.51%	4.79%	7/22/1992	7.83%
5/11/2005	4.5451	4.55%	4.80%	7/23/1992	7.83%
5/10/2005	4.568	4.57%	4.80%	7/24/1992	7.83%
5/9/2005	4.6239	4.62%	4.80%	7/27/1992	7.82%
5/6/2005	4.6278	4.63%	4.80%	7/28/1992	7.82%
5/5/2005	4.5769	4.58%	4.81%	7/29/1992	7.82%
5/4/2005	4.5903	4.59%	4.81%	7/30/1992	7.82%
5/3/2005	4.482	4.48%	4.81%	7/31/1992	7.81%
5/2/2005	4.5132	4.51%	4.82%	8/3/1992	7.81%
4/29/2005	4.5133	4.51%	4.82%	8/4/1992	7.81%
4/28/2005	4.4851	4.49%	4.83%	8/5/1992	7.80%
4/27/2005	4.5476	4.55%	4.83%	8/6/1992	7.80%
4/26/2005	4.5715	4.57%	4.83%	8/7/1992	7.80%
4/25/2005	4.5534	4.55%	4.83%	8/10/1992	7.80%
4/22/2005	4.5793	4.58%	4.84%	8/11/1992	7.79%
4/21/2005	4.6363	4.64%	4.84%	8/12/1992	7.79%
4/20/2005	4.5479	4.55%	4.84%	8/13/1992	7.79%
4/19/2005	4.5423	4.54%	4.85%	8/14/1992	7.78%
4/18/2005	4.6093	4.61%	4.85%	8/17/1992	7.78%
4/15/2005	4.6084	4.61%	4.85%	8/18/1992	7.78%
4/14/2005	4.6804	4.68%	4.86%	8/19/1992	7.77%
4/13/2005	4.6814	4.68%	4.86%	8/20/1992	7.77%
4/12/2005	4.658	4.66%	4.86%	8/21/1992	7.77%
4/11/2005	4.7237	4.72%	4.86%	8/24/1992	7.77%
4/8/2005	4.7683	4.77%	4.87%	8/25/1992	7.77%
4/7/2005	4.7944	4.79%	4.87%	8/26/1992	7.76%
4/6/2005	4.7337	4.73%	4.87%	8/27/1992	7.76%
4/5/2005	4.7516	4.75%	4.87%	8/28/1992	7.76%
4/4/2005	4.7348	4.73%	4.88%	8/31/1992	7.76%
4/1/2005	4.721	4.72%	4.88%	9/1/1992	7.75%
3/31/2005	4.7548	4.75%	4.88%	9/2/1992	7.75%

3/30/2005	4.7976	4.80%	4.89%	9/3/1992	7.75%
3/29/2005	4.8409	4.84%	4.89%	9/4/1992	7.74%
3/28/2005	4.8886	4.89%	4.89%	9/8/1992	7.74%
3/25/2005	4.844	4.84%	4.89%	9/9/1992	7.74%
3/24/2005	4.844	4.84%	4.90%	9/10/1992	7.73%
3/23/2005	4.8502	4.85%	4.90%	9/11/1992	7.73%
3/22/2005	4.9051	4.91%	4.90%	9/14/1992	7.73%
3/21/2005	4.8351	4.84%	4.90%	9/15/1992	7.72%
3/18/2005	4.81	4.81%	4.91%	9/16/1992	7.72%
3/17/2005	4.7662	4.77%	4.91%	9/17/1992	7.72%
3/16/2005	4.7941	4.79%	4.92%	9/18/1992	7.72%
3/15/2005	4.8253	4.83%	4.92%	9/21/1992	7.72%
3/14/2005	4.7793	4.78%	4.92%	9/22/1992	7.71%
3/11/2005	4.8093	4.81%	4.92%	9/23/1992	7.71%
3/10/2005	4.7635	4.76%	4.93%	9/24/1992	7.71%
3/9/2005	4.8305	4.83%	4.93%	9/25/1992	7.71%
3/8/2005	4.7073	4.71%	4.93%	9/28/1992	7.71%
3/7/2005	4.6237	4.62%	4.94%	9/29/1992	7.71%
3/4/2005	4.6489	4.65%	4.94%	9/30/1992	7.70%
3/3/2005	4.7381	4.74%	4.94%	10/1/1992	7.70%
3/2/2005	4.7341	4.73%	4.95%	10/2/1992	7.70%
3/1/2005	4.7145	4.71%	4.95%	10/5/1992	7.70%
2/28/2005	4.7195	4.72%	4.95%	10/6/1992	7.70%
2/25/2005	4.6386	4.64%	4.96%	10/7/1992	7.70%
2/24/2005	4.6688	4.67%	4.96%	10/8/1992	7.70%
2/23/2005	4.6523	4.65%	4.97%	10/9/1992	7.70%
2/22/2005	4.6854	4.69%	4.97%	10/12/1992	7.70%
2/21/2005	4.6446	4.64%	4.97%	10/13/1992	7.70%
2/18/2005	4.6495	4.65%	4.98%	10/14/1992	7.70%
2/17/2005	4.5738	4.57%	4.98%	10/15/1992	7.70%
2/16/2005	4.5179	4.52%	4.99%	10/16/1992	7.70%
2/15/2005	4.4851	4.49%	4.99%	10/19/1992	7.70%
2/14/2005	4.4488	4.45%	5.00%	10/20/1992	7.71%
2/11/2005	4.4805	4.48%	5.00%	10/21/1992	7.71%
2/10/2005	4.4732	4.47%	5.01%	10/22/1992	7.71%
2/9/2005	4.3689	4.37%	5.01%	10/23/1992	7.71%
2/8/2005	4.3735	4.37%	5.02%	10/26/1992	7.71%
2/7/2005	4.4222	4.42%	5.02%	10/27/1992	7.71%
2/4/2005	4.4817	4.48%	5.03%	10/28/1992	7.71%
2/3/2005	4.581	4.58%	5.03%	10/29/1992	7.71%
2/2/2005	4.5791	4.58%	5.03%	10/30/1992	7.71%
2/1/2005	4.5944	4.59%	5.04%	11/2/1992	7.71%
1/31/2005	4.5849	4.58%	5.04%	11/3/1992	7.71%
1/28/2005	4.6079	4.61%	5.04%	11/4/1992	7.71%
1/27/2005	4.6843	4.68%	5.05%	11/5/1992	7.71%
1/26/2005	4.6668	4.67%	5.05%	11/6/1992	7.71%
1/25/2005	4.6814	4.68%	5.05%	11/9/1992	7.71%

1/24/2005	4.6004	4.60%	5.05%	11/10/1992	7.71%
1/21/2005	4.6427	4.64%	5.06%	11/11/1992	7.70%
1/20/2005	4.6563	4.66%	5.06%	11/12/1992	7.70%
1/19/2005	4.6554	4.66%	5.06%	11/13/1992	7.70%
1/18/2005	4.6787	4.68%	5.07%	11/16/1992	7.70%
1/17/2005	4.7256	4.73%	5.07%	11/17/1992	7.70%
1/14/2005	4.7276	4.73%	5.07%	11/18/1992	7.70%
1/13/2005	4.6896	4.69%	5.07%	11/19/1992	7.70%
1/12/2005	4.7672	4.77%	5.07%	11/20/1992	7.70%
1/11/2005	4.7801	4.78%	5.07%	11/23/1992	7.70%
1/10/2005	4.817	4.82%	5.07%	11/24/1992	7.69%
1/7/2005	4.835	4.84%	5.08%	11/25/1992	7.69%
1/6/2005	4.8451	4.85%	5.08%	11/26/1992	7.69%
1/5/2005	4.8472	4.85%	5.08%	11/27/1992	7.69%
1/4/2005	4.8856	4.89%	5.08%	11/30/1992	7.69%
1/3/2005	4.8121	4.81%	5.08%	12/1/1992	7.68%
12/31/2004	4.8261	4.83%	5.08%	12/2/1992	7.68%
12/30/2004	4.8725	4.87%	5.08%	12/3/1992	7.68%
12/29/2004	4.9428	4.94%	5.07%	12/4/1992	7.68%
12/28/2004	4.9152	4.92%	5.07%	12/7/1992	7.68%
12/27/2004	4.9192	4.92%	5.07%	12/8/1992	7.67%
12/24/2004	4.8443	4.84%	5.07%	12/9/1992	7.67%
12/23/2004	4.8423	4.84%	5.07%	12/10/1992	7.67%
12/22/2004	4.8274	4.83%	5.07%	12/11/1992	7.67%
12/21/2004	4.7955	4.80%	5.07%	12/14/1992	7.66%
12/20/2004	4.8114	4.81%	5.07%	12/15/1992	7.66%
12/17/2004	4.8265	4.83%	5.07%	12/16/1992	7.66%
12/16/2004	4.8245	4.82%	5.07%	12/17/1992	7.66%
12/15/2004	4.7109	4.71%	5.07%	12/18/1992	7.65%
12/14/2004	4.7689	4.77%	5.07%	12/21/1992	7.65%
12/13/2004	4.8036	4.80%	5.06%	12/22/1992	7.65%
12/10/2004	4.8176	4.82%	5.06%	12/23/1992	7.64%
12/9/2004	4.8327	4.83%	5.06%	12/24/1992	7.64%
12/8/2004	4.7829	4.78%	5.06%	12/25/1992	7.64%
12/7/2004	4.8871	4.89%	5.06%	12/28/1992	7.64%
12/6/2004	4.8922	4.89%	5.06%	12/29/1992	7.63%
12/3/2004	4.9268	4.93%	5.06%	12/30/1992	7.63%
12/2/2004	5.0614	5.06%	5.06%	12/31/1992	7.63%
12/1/2004	5.0113	5.01%	5.06%	1/4/1993	7.62%
11/30/2004	5.002	5.00%	5.06%	1/5/1993	7.62%
11/29/2004	4.9638	4.96%	5.06%	1/6/1993	7.62%
11/26/2004	4.8853	4.89%	5.06%	1/7/1993	7.61%
11/25/2004	4.839	4.84%	5.06%	1/8/1993	7.61%
11/24/2004	4.8431	4.84%	5.06%	1/11/1993	7.61%
11/23/2004	4.8361	4.84%	5.06%	1/12/1993	7.61%
11/22/2004	4.8421	4.84%	5.06%	1/13/1993	7.60%
11/19/2004	4.8844	4.88%	5.06%	1/14/1993	7.60%

11/18/2004	4.8063	4.81%	5.06%	1/15/1993	7.60%
11/17/2004	4.8402	4.84%	5.06%	1/18/1993	7.60%
11/16/2004	4.9008	4.90%	5.06%	1/19/1993	7.59%
11/15/2004	4.8957	4.90%	5.06%	1/20/1993	7.59%
11/12/2004	4.8967	4.90%	5.06%	1/21/1993	7.59%
11/11/2004	4.9672	4.97%	5.07%	1/22/1993	7.59%
11/10/2004	4.958	4.96%	5.07%	1/25/1993	7.58%
11/9/2004	4.9437	4.94%	5.07%	1/26/1993	7.58%
11/8/2004	4.9315	4.93%	5.07%	1/27/1993	7.58%
11/5/2004	4.8969	4.90%	5.07%	1/28/1993	7.57%
11/4/2004	4.8146	4.81%	5.07%	1/29/1993	7.57%
11/3/2004	4.8256	4.83%	5.07%	2/1/1993	7.56%
11/2/2004	4.8127	4.81%	5.07%	2/2/1993	7.56%
11/1/2004	4.8357	4.84%	5.07%	2/3/1993	7.55%
10/29/2004	4.7889	4.79%	5.07%	2/4/1993	7.55%
10/28/2004	4.8168	4.82%	5.07%	2/5/1993	7.55%
10/27/2004	4.8438	4.84%	5.07%	2/8/1993	7.54%
10/26/2004	4.7733	4.77%	5.07%	2/9/1993	7.54%
10/25/2004	4.7526	4.75%	5.07%	2/10/1993	7.53%
10/22/2004	4.7605	4.76%	5.07%	2/11/1993	7.53%
10/21/2004	4.7695	4.77%	5.07%	2/12/1993	7.52%
10/20/2004	4.7725	4.77%	5.07%	2/15/1993	7.52%
10/19/2004	4.8151	4.82%	5.07%	2/16/1993	7.52%
10/18/2004	4.8381	4.84%	5.07%	2/17/1993	7.51%
10/15/2004	4.8451	4.85%	5.07%	2/18/1993	7.51%
10/14/2004	4.8222	4.82%	5.07%	2/19/1993	7.50%
10/13/2004	4.8683	4.87%	5.08%	2/22/1993	7.50%
10/12/2004	4.8784	4.88%	5.08%	2/23/1993	7.49%
10/11/2004	4.8986	4.90%	5.08%	2/24/1993	7.49%
10/8/2004	4.9067	4.91%	5.08%	2/25/1993	7.48%
10/7/2004	4.9948	4.99%	5.08%	2/26/1993	7.48%
10/6/2004	4.968	4.97%	5.08%	3/1/1993	7.48%
10/5/2004	4.9313	4.93%	5.08%	3/2/1993	7.47%
10/4/2004	4.9272	4.93%	5.08%	3/3/1993	7.47%
10/1/2004	4.9436	4.94%	5.08%	3/4/1993	7.46%
9/30/2004	4.8919	4.89%	5.08%	3/5/1993	7.45%
9/29/2004	4.8657	4.87%	5.08%	3/8/1993	7.45%
9/28/2004	4.7979	4.80%	5.08%	3/9/1993	7.44%
9/27/2004	4.7683	4.77%	5.09%	3/10/1993	7.44%
9/24/2004	4.798	4.80%	5.09%	3/11/1993	7.43%
9/23/2004	4.7902	4.79%	5.09%	3/12/1993	7.43%
9/22/2004	4.7734	4.77%	5.09%	3/15/1993	7.42%
9/21/2004	4.8379	4.84%	5.09%	3/16/1993	7.42%
9/20/2004	4.866	4.87%	5.09%	3/17/1993	7.41%
9/17/2004	4.9095	4.91%	5.09%	3/18/1993	7.41%
9/16/2004	4.8731	4.87%	5.09%	3/19/1993	7.40%
9/15/2004	4.9594	4.96%	5.09%	3/22/1993	7.39%

9/14/2004	4.9329	4.93%	5.09%	3/23/1993	7.39%
9/13/2004	4.941	4.94%	5.10%	3/24/1993	7.38%
9/10/2004	4.9841	4.98%	5.10%	3/25/1993	7.38%
9/9/2004	4.9883	4.99%	5.10%	3/26/1993	7.37%
9/8/2004	4.9534	4.95%	5.10%	3/29/1993	7.37%
9/7/2004	5.0089	5.01%	5.10%	3/30/1993	7.37%
9/6/2004	5.0598	5.06%	5.10%	3/31/1993	7.36%
9/3/2004	5.0578	5.06%	5.10%	4/1/1993	7.36%
9/2/2004	5.0008	5.00%	5.10%	4/2/1993	7.35%
9/1/2004	4.9251	4.93%	5.10%	4/5/1993	7.35%
8/31/2004	4.9272	4.93%	5.10%	4/6/1993	7.35%
8/30/2004	4.9803	4.98%	5.10%	4/7/1993	7.34%
8/27/2004	5.0195	5.02%	5.10%	4/8/1993	7.34%
8/26/2004	5.0082	5.01%	5.10%	4/9/1993	7.33%
8/25/2004	5.0477	5.05%	5.10%	4/12/1993	7.33%
8/24/2004	5.0633	5.06%	5.10%	4/13/1993	7.32%
8/23/2004	5.0738	5.07%	5.10%	4/14/1993	7.32%
8/20/2004	5.0239	5.02%	5.10%	4/15/1993	7.31%
8/19/2004	5.026	5.03%	5.10%	4/16/1993	7.31%
8/18/2004	5.0374	5.04%	5.10%	4/19/1993	7.31%
8/17/2004	5.0033	5.00%	5.10%	4/20/1993	7.30%
8/16/2004	5.05	5.05%	5.11%	4/21/1993	7.30%
8/13/2004	5.0168	5.02%	5.11%	4/22/1993	7.29%
8/12/2004	5.048	5.05%	5.11%	4/23/1993	7.29%
8/11/2004	5.0553	5.06%	5.11%	4/26/1993	7.28%
8/10/2004	5.0667	5.07%	5.11%	4/27/1993	7.28%
8/9/2004	5.0584	5.06%	5.11%	4/28/1993	7.28%
8/6/2004	5.0355	5.04%	5.11%	4/29/1993	7.27%
8/5/2004	5.1531	5.15%	5.11%	4/30/1993	7.27%
8/4/2004	5.1648	5.16%	5.11%	5/3/1993	7.27%
8/3/2004	5.1669	5.17%	5.11%	5/4/1993	7.26%
8/2/2004	5.1883	5.19%	5.11%	5/5/1993	7.26%
7/30/2004	5.1969	5.20%	5.11%	5/6/1993	7.26%
7/29/2004	5.2943	5.29%	5.11%	5/7/1993	7.25%
7/28/2004	5.3118	5.31%	5.11%	5/10/1993	7.25%
7/27/2004	5.3173	5.32%	5.11%	5/11/1993	7.25%
7/26/2004	5.2097	5.21%	5.11%	5/12/1993	7.24%
7/23/2004	5.1659	5.17%	5.11%	5/13/1993	7.24%
7/22/2004	5.1861	5.19%	5.11%	5/14/1993	7.24%
7/21/2004	5.1979	5.20%	5.11%	5/17/1993	7.24%
7/20/2004	5.1733	5.17%	5.11%	5/18/1993	7.23%
7/19/2004	5.1098	5.11%	5.11%	5/19/1993	7.23%
7/16/2004	5.115	5.12%	5.11%	5/20/1993	7.23%
7/15/2004	5.2119	5.21%	5.11%	5/21/1993	7.23%
7/14/2004	5.2172	5.22%	5.11%	5/24/1993	7.23%
7/13/2004	5.2097	5.21%	5.11%	5/25/1993	7.23%
7/12/2004	5.1979	5.20%	5.11%	5/26/1993	7.22%

7/9/2004	5.2065	5.21%	5.11%	5/27/1993	7.22%
7/8/2004	5.2226	5.22%	5.11%	5/28/1993	7.22%
7/7/2004	5.2237	5.22%	5.11%	5/31/1993	7.22%
7/6/2004	5.2183	5.22%	5.11%	6/1/1993	7.22%
7/5/2004	5.2054	5.21%	5.10%	6/2/1993	7.21%
7/2/2004	5.2054	5.21%	5.10%	6/3/1993	7.21%
7/1/2004	5.2865	5.29%	5.10%	6/4/1993	7.21%
6/30/2004	5.2876	5.29%	5.10%	6/7/1993	7.20%
6/29/2004	5.3645	5.36%	5.10%	6/8/1993	7.20%
6/28/2004	5.4079	5.41%	5.10%	6/9/1993	7.20%
6/25/2004	5.3347	5.33%	5.10%	6/10/1993	7.20%
6/24/2004	5.3369	5.34%	5.09%	6/11/1993	7.19%
6/23/2004	5.3823	5.38%	5.09%	6/14/1993	7.19%
6/22/2004	5.4045	5.40%	5.09%	6/15/1993	7.19%
6/21/2004	5.3678	5.37%	5.09%	6/16/1993	7.19%
6/18/2004	5.3767	5.38%	5.09%	6/17/1993	7.18%
6/17/2004	5.3501	5.35%	5.09%	6/18/1993	7.18%
6/16/2004	5.4	5.40%	5.09%	6/21/1993	7.18%
6/15/2004	5.3634	5.36%	5.09%	6/22/1993	7.18%
6/14/2004	5.53	5.53%	5.09%	6/23/1993	7.17%
6/11/2004	5.4742	5.47%	5.08%	6/24/1993	7.17%
6/10/2004	5.4685	5.47%	5.08%	6/25/1993	7.17%
6/9/2004	5.4798	5.48%	5.08%	6/28/1993	7.16%
6/8/2004	5.4482	5.45%	5.08%	6/29/1993	7.16%
6/7/2004	5.4527	5.45%	5.08%	6/30/1993	7.16%
6/4/2004	5.4572	5.46%	5.08%	7/1/1993	7.15%
6/3/2004	5.4145	5.41%	5.08%	7/2/1993	7.15%
6/2/2004	5.4268	5.43%	5.08%	7/5/1993	7.15%
6/1/2004	5.3955	5.40%	5.08%	7/6/1993	7.14%
5/31/2004	5.3446	5.34%	5.08%	7/7/1993	7.14%
5/28/2004	5.3445	5.34%	5.08%	7/8/1993	7.14%
5/27/2004	5.3149	5.31%	5.08%	7/9/1993	7.13%
5/26/2004	5.3644	5.36%	5.08%	7/12/1993	7.13%
5/25/2004	5.41	5.41%	5.08%	7/13/1993	7.13%
5/24/2004	5.4323	5.43%	5.07%	7/14/1993	7.12%
5/21/2004	5.4582	5.46%	5.07%	7/15/1993	7.12%
5/20/2004	5.4189	5.42%	5.07%	7/16/1993	7.11%
5/19/2004	5.4762	5.48%	5.07%	7/19/1993	7.11%
5/18/2004	5.4537	5.45%	5.07%	7/20/1993	7.10%
5/17/2004	5.4222	5.42%	5.07%	7/21/1993	7.10%
5/14/2004	5.4853	5.49%	5.07%	7/22/1993	7.09%
5/13/2004	5.5606	5.56%	5.07%	7/23/1993	7.09%
5/12/2004	5.5217	5.52%	5.07%	7/26/1993	7.08%
5/11/2004	5.4525	5.45%	5.07%	7/27/1993	7.08%
5/10/2004	5.4909	5.49%	5.07%	7/28/1993	7.08%
5/7/2004	5.466	5.47%	5.07%	7/29/1993	7.07%
5/6/2004	5.3666	5.37%	5.07%	7/30/1993	7.06%

5/5/2004	5.3567	5.36%	5.07%	8/2/1993	7.06%
5/4/2004	5.3435	5.34%	5.06%	8/3/1993	7.05%
5/3/2004	5.2779	5.28%	5.06%	8/4/1993	7.05%
4/30/2004	5.2844	5.28%	5.06%	8/5/1993	7.04%
4/29/2004	5.3139	5.31%	5.06%	8/6/1993	7.04%
4/28/2004	5.2856	5.29%	5.06%	8/9/1993	7.03%
4/27/2004	5.1994	5.20%	5.06%	8/10/1993	7.03%
4/26/2004	5.2272	5.23%	5.06%	8/11/1993	7.02%
4/23/2004	5.2391	5.24%	5.06%	8/12/1993	7.01%
4/22/2004	5.1941	5.19%	5.06%	8/13/1993	7.01%
4/21/2004	5.2262	5.23%	5.06%	8/16/1993	7.00%
4/20/2004	5.2607	5.26%	5.06%	8/17/1993	6.99%
4/19/2004	5.2091	5.21%	5.05%	8/18/1993	6.99%
4/16/2004	5.1687	5.17%	5.05%	8/19/1993	6.98%
4/15/2004	5.2092	5.21%	5.05%	8/20/1993	6.97%
4/14/2004	5.1592	5.16%	5.05%	8/23/1993	6.96%
4/13/2004	5.155	5.16%	5.04%	8/24/1993	6.96%
4/12/2004	5.0597	5.06%	5.04%	8/25/1993	6.95%
4/9/2004	5.0277	5.03%	5.04%	8/26/1993	6.94%
4/8/2004	5.0278	5.03%	5.04%	8/27/1993	6.94%
4/7/2004	5.0042	5.00%	5.04%	8/30/1993	6.93%
4/6/2004	4.9971	5.00%	5.03%	8/31/1993	6.92%
4/5/2004	5.0413	5.04%	5.03%	9/1/1993	6.92%
4/2/2004	4.9777	4.98%	5.03%	9/2/1993	6.91%
4/1/2004	4.8009	4.80%	5.03%	9/3/1993	6.90%
3/31/2004	4.7716	4.77%	5.03%	9/6/1993	6.89%
3/30/2004	4.8128	4.81%	5.03%	9/7/1993	6.88%
3/29/2004	4.8099	4.81%	5.02%	9/8/1993	6.87%
3/26/2004	4.761	4.76%	5.02%	9/9/1993	6.87%
3/25/2004	4.6916	4.69%	5.02%	9/10/1993	6.86%
3/24/2004	4.6582	4.66%	5.02%	9/13/1993	6.85%
3/23/2004	4.6516	4.65%	5.02%	9/14/1993	6.84%
3/22/2004	4.664	4.66%	5.01%	9/15/1993	6.84%
3/19/2004	4.7042	4.70%	5.01%	9/16/1993	6.83%
3/18/2004	4.6996	4.70%	5.01%	9/17/1993	6.82%
3/17/2004	4.6642	4.66%	5.01%	9/20/1993	6.81%
3/16/2004	4.6424	4.64%	5.01%	9/21/1993	6.81%
3/15/2004	4.7054	4.71%	5.00%	9/22/1993	6.80%
3/12/2004	4.717	4.72%	5.00%	9/23/1993	6.79%
3/11/2004	4.6645	4.66%	5.00%	9/24/1993	6.79%
3/10/2004	4.6693	4.67%	5.00%	9/27/1993	6.78%
3/9/2004	4.6693	4.67%	5.00%	9/28/1993	6.77%
3/8/2004	4.7076	4.71%	5.00%	9/29/1993	6.77%
3/5/2004	4.7628	4.76%	4.99%	9/30/1993	6.76%
3/4/2004	4.8769	4.88%	4.99%	10/1/1993	6.75%
3/3/2004	4.9029	4.90%	4.99%	10/4/1993	6.75%
3/2/2004	4.901	4.90%	4.99%	10/5/1993	6.74%

3/1/2004	4.8384	4.84%	4.98%	10/6/1993	6.73%
2/27/2004	4.8374	4.84%	4.98%	10/7/1993	6.73%
2/26/2004	4.9051	4.91%	4.98%	10/8/1993	6.72%
2/25/2004	4.8862	4.89%	4.98%	10/12/1993	6.71%
2/24/2004	4.8962	4.90%	4.97%	10/13/1993	6.70%
2/23/2004	4.9012	4.90%	4.97%	10/14/1993	6.70%
2/20/2004	4.9525	4.95%	4.97%	10/15/1993	6.69%
2/19/2004	4.8944	4.89%	4.97%	10/18/1993	6.68%
2/18/2004	4.9104	4.91%	4.96%	10/19/1993	6.67%
2/17/2004	4.9114	4.91%	4.96%	10/20/1993	6.66%
2/16/2004	4.9164	4.92%	4.96%	10/21/1993	6.66%
2/13/2004	4.9165	4.92%	4.96%	10/22/1993	6.65%
2/12/2004	4.9266	4.93%	4.96%	10/25/1993	6.64%
2/11/2004	4.8995	4.90%	4.96%	10/26/1993	6.64%
2/10/2004	4.9498	4.95%	4.96%	10/27/1993	6.63%
2/9/2004	4.8996	4.90%	4.95%	10/28/1993	6.62%
2/6/2004	4.9166	4.92%	4.95%	10/29/1993	6.62%
2/5/2004	4.9812	4.98%	4.95%	11/1/1993	6.61%
2/4/2004	4.9549	4.95%	4.95%	11/2/1993	6.60%
2/3/2004	4.9488	4.95%	4.95%	11/3/1993	6.60%
2/2/2004	4.9833	4.98%	4.95%	11/4/1993	6.59%
1/30/2004	4.961	4.96%	4.95%	11/5/1993	6.59%
1/29/2004	4.9996	5.00%	4.95%	11/8/1993	6.58%
1/28/2004	5.0026	5.00%	4.95%	11/9/1993	6.58%
1/27/2004	4.9368	4.94%	4.95%	11/10/1993	6.57%
1/26/2004	4.9833	4.98%	4.95%	11/12/1993	6.57%
1/23/2004	4.9429	4.94%	4.95%	11/15/1993	6.56%
1/22/2004	4.8433	4.84%	4.95%	11/16/1993	6.56%
1/21/2004	4.9038	4.90%	4.95%	11/17/1993	6.55%
1/20/2004	4.9238	4.92%	4.95%	11/18/1993	6.55%
1/19/2004	4.8918	4.89%	4.95%	11/19/1993	6.54%
1/16/2004	4.8919	4.89%	4.95%	11/22/1993	6.54%
1/15/2004	4.8552	4.86%	4.95%	11/23/1993	6.53%
1/14/2004	4.8939	4.89%	4.95%	11/24/1993	6.53%
1/13/2004	4.9189	4.92%	4.95%	11/25/1993	6.53%
1/12/2004	4.9723	4.97%	4.95%	11/26/1993	6.52%
1/9/2004	4.9592	4.96%	4.95%	11/29/1993	6.52%
1/8/2004	5.085	5.09%	4.95%	11/30/1993	6.51%
1/7/2004	5.0757	5.08%	4.95%	12/1/1993	6.51%
1/6/2004	5.1006	5.10%	4.95%	12/2/1993	6.51%
1/5/2004	5.1772	5.18%	4.95%	12/3/1993	6.50%
1/2/2004	5.1698	5.17%	4.94%	12/6/1993	6.50%
1/1/2004	5.0726	5.07%	4.94%	12/7/1993	6.50%
12/31/2003	5.0727	5.07%	4.94%	12/8/1993	6.49%
12/30/2003	5.0748	5.07%	4.94%	12/9/1993	6.49%
12/29/2003	5.0469	5.05%	4.94%	12/10/1993	6.49%
12/26/2003	4.9694	4.97%	4.94%	12/13/1993	6.49%

12/25/2003	4.9857	4.99%	4.94%	12/14/1993	6.48%
12/24/2003	4.9857	4.99%	4.94%	12/15/1993	6.48%
12/23/2003	5.0511	5.05%	4.94%	12/16/1993	6.48%
12/22/2003	4.9796	4.98%	4.94%	12/17/1993	6.48%
12/19/2003	4.9645	4.96%	4.94%	12/20/1993	6.47%
12/18/2003	4.9434	4.94%	4.94%	12/21/1993	6.47%
12/17/2003	5.0214	5.02%	4.94%	12/22/1993	6.47%
12/16/2003	5.0646	5.06%	4.93%	12/23/1993	6.46%
12/15/2003	5.0956	5.10%	4.93%	12/24/1993	6.46%
12/12/2003	5.0904	5.09%	4.93%	12/27/1993	6.46%
12/11/2003	5.1019	5.10%	4.93%	12/28/1993	6.46%
12/10/2003	5.1489	5.15%	4.92%	12/29/1993	6.45%
12/9/2003	5.1636	5.16%	4.92%	12/30/1993	6.45%
12/8/2003	5.1092	5.11%	4.92%	12/31/1993	6.45%
12/5/2003	5.0616	5.06%	4.92%	1/3/1994	6.45%
12/4/2003	5.1604	5.16%	4.92%	1/4/1994	6.44%
12/3/2003	5.1847	5.18%	4.91%	1/5/1994	6.44%
12/2/2003	5.15	5.15%	4.91%	1/6/1994	6.44%
12/1/2003	5.151	5.15%	4.91%	1/7/1994	6.43%
11/28/2003	5.1311	5.13%	4.91%	1/10/1994	6.43%
11/27/2003	5.0689	5.07%	4.91%	1/11/1994	6.43%
11/26/2003	5.0689	5.07%	4.91%	1/12/1994	6.42%
11/25/2003	5.0289	5.03%	4.90%	1/13/1994	6.42%
11/24/2003	5.0648	5.06%	4.90%	1/14/1994	6.42%
11/21/2003	5.0146	5.01%	4.90%	1/17/1994	6.41%
11/20/2003	5.0085	5.01%	4.90%	1/18/1994	6.41%
11/19/2003	5.0814	5.08%	4.90%	1/19/1994	6.41%
11/18/2003	4.9984	5.00%	4.90%	1/20/1994	6.41%
11/17/2003	5.0474	5.05%	4.90%	1/21/1994	6.40%
11/14/2003	5.0505	5.05%	4.90%	1/24/1994	6.40%
11/13/2003	5.1042	5.10%	4.90%	1/25/1994	6.40%
11/12/2003	5.2081	5.21%	4.89%	1/26/1994	6.40%
11/11/2003	5.2636	5.26%	4.89%	1/27/1994	6.39%
11/10/2003	5.2636	5.26%	4.89%	1/28/1994	6.39%
11/7/2003	5.2529	5.25%	4.89%	1/31/1994	6.39%
11/6/2003	5.2433	5.24%	4.89%	2/1/1994	6.39%
11/5/2003	5.1828	5.18%	4.88%	2/2/1994	6.38%
11/4/2003	5.1283	5.13%	4.88%	2/3/1994	6.38%
11/3/2003	5.1607	5.16%	4.88%	2/4/1994	6.38%
10/31/2003	5.1314	5.13%	4.88%	2/7/1994	6.38%
10/30/2003	5.1977	5.20%	4.88%	2/8/1994	6.37%
10/29/2003	5.1755	5.18%	4.88%	2/9/1994	6.37%
10/28/2003	5.0899	5.09%	4.88%	2/10/1994	6.37%
10/27/2003	5.1399	5.14%	4.88%	2/11/1994	6.37%
10/24/2003	5.119	5.12%	4.87%	2/14/1994	6.37%
10/23/2003	5.1946	5.19%	4.87%	2/15/1994	6.36%
10/22/2003	5.1347	5.13%	4.87%	2/16/1994	6.36%

10/21/2003	5.2052	5.21%	4.87%	2/17/1994	6.36%
10/20/2003	5.2349	5.23%	4.87%	2/18/1994	6.36%
10/17/2003	5.2488	5.25%	4.87%	2/21/1994	6.36%
10/16/2003	5.3047	5.30%	4.87%	2/22/1994	6.36%
10/15/2003	5.2875	5.29%	4.87%	2/23/1994	6.35%
10/14/2003	5.251	5.25%	4.87%	2/24/1994	6.35%
10/13/2003	5.1778	5.18%	4.86%	2/25/1994	6.35%
10/10/2003	5.1799	5.18%	4.86%	2/28/1994	6.35%
10/9/2003	5.2138	5.21%	4.86%	3/1/1994	6.35%
10/8/2003	5.16	5.16%	4.86%	3/2/1994	6.35%
10/7/2003	5.1569	5.16%	4.86%	3/3/1994	6.35%
10/6/2003	5.0687	5.07%	4.86%	3/4/1994	6.35%
10/3/2003	5.0955	5.10%	4.85%	3/7/1994	6.35%
10/2/2003	4.9329	4.93%	4.85%	3/8/1994	6.35%
10/1/2003	4.8902	4.89%	4.85%	3/9/1994	6.34%
9/30/2003	4.8823	4.88%	4.85%	3/10/1994	6.35%
9/29/2003	5.0055	5.01%	4.85%	3/11/1994	6.35%
9/26/2003	4.934	4.93%	4.85%	3/14/1994	6.35%
9/25/2003	4.9863	4.99%	4.85%	3/15/1994	6.35%
9/24/2003	5.029	5.03%	4.85%	3/16/1994	6.35%
9/23/2003	5.0916	5.09%	4.85%	3/17/1994	6.34%
9/22/2003	5.1248	5.12%	4.85%	3/18/1994	6.34%
9/19/2003	5.0679	5.07%	4.85%	3/21/1994	6.35%
9/18/2003	5.0742	5.07%	4.85%	3/22/1994	6.35%
9/17/2003	5.0865	5.09%	4.85%	3/23/1994	6.35%
9/16/2003	5.194	5.19%	4.85%	3/24/1994	6.35%
9/15/2003	5.1824	5.18%	4.85%	3/25/1994	6.35%
9/12/2003	5.1594	5.16%	4.84%	3/28/1994	6.35%
9/11/2003	5.2036	5.20%	4.84%	3/29/1994	6.35%
9/10/2003	5.1532	5.15%	4.84%	3/30/1994	6.35%
9/9/2003	5.2259	5.23%	4.84%	3/31/1994	6.35%
9/8/2003	5.2632	5.26%	4.84%	4/1/1994	6.36%
9/5/2003	5.1878	5.19%	4.84%	4/4/1994	6.36%
9/4/2003	5.3052	5.31%	4.84%	4/5/1994	6.36%
9/3/2003	5.3496	5.35%	4.84%	4/6/1994	6.36%
9/2/2003	5.3333	5.33%	4.84%	4/7/1994	6.37%
9/1/2003	5.2217	5.22%	4.84%	4/8/1994	6.37%
8/29/2003	5.2228	5.22%	4.83%	4/11/1994	6.37%
8/28/2003	5.207	5.21%	4.83%	4/12/1994	6.38%
8/27/2003	5.3128	5.31%	4.83%	4/13/1994	6.38%
8/26/2003	5.2709	5.27%	4.83%	4/14/1994	6.38%
8/25/2003	5.3021	5.30%	4.83%	4/15/1994	6.38%
8/22/2003	5.2581	5.26%	4.83%	4/18/1994	6.39%
8/21/2003	5.2753	5.28%	4.82%	4/19/1994	6.39%
8/20/2003	5.2849	5.28%	4.82%	4/20/1994	6.40%
8/19/2003	5.2422	5.24%	4.82%	4/21/1994	6.40%
8/18/2003	5.3444	5.34%	4.82%	4/22/1994	6.40%

8/15/2003	5.3969	5.40%	4.82%	4/25/1994	6.41%
8/14/2003	5.3805	5.38%	4.81%	4/26/1994	6.41%
8/13/2003	5.4489	5.45%	4.81%	4/27/1994	6.41%
8/12/2003	5.3499	5.35%	4.81%	4/28/1994	6.41%
8/11/2003	5.2689	5.27%	4.81%	4/29/1994	6.42%
8/8/2003	5.2305	5.23%	4.81%	5/2/1994	6.42%
8/7/2003	5.2136	5.21%	4.80%	5/3/1994	6.42%
8/6/2003	5.2369	5.24%	4.80%	5/4/1994	6.43%
8/5/2003	5.3607	5.36%	4.80%	5/5/1994	6.43%
8/4/2003	5.2518	5.25%	4.80%	5/6/1994	6.44%
8/1/2003	5.314	5.31%	4.80%	5/9/1994	6.44%
7/31/2003	5.3574	5.36%	4.80%	5/10/1994	6.45%
7/30/2003	5.2475	5.25%	4.80%	5/11/1994	6.45%
7/29/2003	5.3367	5.34%	4.80%	5/12/1994	6.46%
7/28/2003	5.2135	5.21%	4.80%	5/13/1994	6.46%
7/25/2003	5.1163	5.12%	4.80%	5/16/1994	6.47%
7/24/2003	5.0915	5.09%	4.80%	5/17/1994	6.47%
7/23/2003	5.0413	5.04%	4.80%	5/18/1994	6.47%
7/22/2003	5.0403	5.04%	4.80%	5/19/1994	6.48%
7/21/2003	5.0874	5.09%	4.79%	5/20/1994	6.48%
7/18/2003	4.9326	4.93%	4.79%	5/23/1994	6.49%
7/17/2003	4.892	4.89%	4.79%	5/24/1994	6.49%
7/16/2003	4.893	4.89%	4.79%	5/25/1994	6.50%
7/15/2003	4.9646	4.96%	4.79%	5/26/1994	6.50%
7/14/2003	4.7693	4.77%	4.79%	5/27/1994	6.51%
7/11/2003	4.6818	4.68%	4.79%	5/30/1994	6.51%
7/10/2003	4.697	4.70%	4.79%	5/31/1994	6.52%
7/9/2003	4.697	4.70%	4.79%	6/1/1994	6.53%
7/8/2003	4.7131	4.71%	4.79%	6/2/1994	6.53%
7/7/2003	4.7455	4.75%	4.79%	6/3/1994	6.54%
7/4/2003	4.6838	4.68%	4.79%	6/6/1994	6.54%
7/3/2003	4.6905	4.69%	4.79%	6/7/1994	6.55%
7/2/2003	4.5795	4.58%	4.79%	6/8/1994	6.55%
7/1/2003	4.586	4.59%	4.79%	6/9/1994	6.56%
6/30/2003	4.5566	4.56%	4.79%	6/10/1994	6.57%
6/27/2003	4.5824	4.58%	4.79%	6/13/1994	6.57%
6/26/2003	4.5641	4.56%	4.79%	6/14/1994	6.58%
6/25/2003	4.4624	4.46%	4.79%	6/15/1994	6.59%
6/24/2003	4.3339	4.33%	4.79%	6/16/1994	6.59%
6/23/2003	4.3956	4.40%	4.80%	6/17/1994	6.60%
6/20/2003	4.432	4.43%	4.80%	6/20/1994	6.61%
6/19/2003	4.4064	4.41%	4.80%	6/21/1994	6.62%
6/18/2003	4.3967	4.40%	4.80%	6/22/1994	6.62%
6/17/2003	4.2995	4.30%	4.80%	6/23/1994	6.63%
6/16/2003	4.2315	4.23%	4.81%	6/24/1994	6.64%
6/13/2003	4.173	4.17%	4.81%	6/27/1994	6.65%
6/12/2003	4.2121	4.21%	4.81%	6/28/1994	6.65%

6/11/2003	4.2618	4.26%	4.82%	6/29/1994	6.66%
6/10/2003	4.2532	4.25%	4.82%	6/30/1994	6.67%
6/9/2003	4.3416	4.34%	4.82%	7/1/1994	6.68%
6/6/2003	4.3962	4.40%	4.82%	7/4/1994	6.68%
6/5/2003	4.4052	4.41%	4.83%	7/5/1994	6.69%
6/4/2003	4.3532	4.35%	4.83%	7/6/1994	6.70%
6/3/2003	4.3691	4.37%	4.83%	7/7/1994	6.71%
6/2/2003	4.4213	4.42%	4.84%	7/8/1994	6.72%
5/30/2003	4.3762	4.38%	4.84%	7/11/1994	6.73%
5/29/2003	4.3395	4.34%	4.84%	7/12/1994	6.73%
5/28/2003	4.4064	4.41%	4.85%	7/13/1994	6.74%
5/27/2003	4.3878	4.39%	4.85%	7/14/1994	6.75%
5/26/2003	4.2574	4.26%	4.85%	7/15/1994	6.76%
5/23/2003	4.2591	4.26%	4.86%	7/18/1994	6.76%
5/22/2003	4.2645	4.26%	4.86%	7/19/1994	6.77%
5/21/2003	4.3486	4.35%	4.86%	7/20/1994	6.78%
5/20/2003	4.3539	4.35%	4.87%	7/21/1994	6.79%
5/19/2003	4.4809	4.48%	4.87%	7/22/1994	6.80%
5/16/2003	4.4139	4.41%	4.87%	7/25/1994	6.81%
5/15/2003	4.4838	4.48%	4.88%	7/26/1994	6.81%
5/14/2003	4.5091	4.51%	4.88%	7/27/1994	6.82%
5/13/2003	4.6108	4.61%	4.88%	7/28/1994	6.83%
5/12/2003	4.6461	4.65%	4.89%	7/29/1994	6.84%
5/9/2003	4.6704	4.67%	4.89%	8/1/1994	6.85%
5/8/2003	4.6809	4.68%	4.89%	8/2/1994	6.85%
5/7/2003	4.6771	4.68%	4.90%	8/3/1994	6.86%
5/6/2003	4.7529	4.75%	4.90%	8/4/1994	6.87%
5/5/2003	4.7999	4.80%	4.90%	8/5/1994	6.88%
5/2/2003	4.8318	4.83%	4.90%	8/8/1994	6.88%
5/1/2003	4.775	4.78%	4.91%	8/9/1994	6.89%
4/30/2003	4.7645	4.76%	4.91%	8/10/1994	6.90%
4/29/2003	4.8378	4.84%	4.91%	8/11/1994	6.91%
4/28/2003	4.8252	4.83%	4.91%	8/12/1994	6.91%
4/25/2003	4.8146	4.81%	4.92%	8/15/1994	6.92%
4/24/2003	4.8369	4.84%	4.92%	8/16/1994	6.92%
4/23/2003	4.8838	4.88%	4.92%	8/17/1994	6.93%
4/22/2003	4.8917	4.89%	4.93%	8/18/1994	6.94%
4/21/2003	4.8976	4.90%	4.93%	8/19/1994	6.94%
4/18/2003	4.8897	4.89%	4.93%	8/22/1994	6.95%
4/17/2003	4.8907	4.89%	4.93%	8/23/1994	6.96%
4/16/2003	4.9066	4.91%	4.93%	8/24/1994	6.96%
4/15/2003	4.9531	4.95%	4.94%	8/25/1994	6.97%
4/14/2003	4.9781	4.98%	4.94%	8/26/1994	6.98%
4/11/2003	4.9482	4.95%	4.94%	8/29/1994	6.98%
4/10/2003	4.9383	4.94%	4.94%	8/30/1994	6.99%
4/9/2003	4.9018	4.90%	4.95%	8/31/1994	6.99%
4/8/2003	4.9255	4.93%	4.95%	9/1/1994	7.00%

4/7/2003	4.9683	4.97%	4.95%	9/2/1994	7.01%
4/4/2003	4.9643	4.96%	4.96%	9/5/1994	7.01%
4/3/2003	4.9276	4.93%	4.96%	9/6/1994	7.02%
4/2/2003	4.9207	4.92%	4.96%	9/7/1994	7.02%
4/1/2003	4.825	4.83%	4.96%	9/8/1994	7.03%
3/31/2003	4.8154	4.82%	4.97%	9/9/1994	7.04%
3/28/2003	4.9129	4.91%	4.97%	9/12/1994	7.05%
3/27/2003	4.9298	4.93%	4.97%	9/13/1994	7.05%
3/26/2003	4.9249	4.92%	4.97%	9/14/1994	7.06%
3/25/2003	4.9239	4.92%	4.98%	9/15/1994	7.07%
3/24/2003	4.9269	4.93%	4.98%	9/16/1994	7.08%
3/21/2003	5.0399	5.04%	4.98%	9/19/1994	7.08%
3/20/2003	4.928	4.93%	4.98%	9/20/1994	7.09%
3/19/2003	4.9251	4.93%	4.99%	9/21/1994	7.10%
3/18/2003	4.876	4.88%	4.99%	9/22/1994	7.11%
3/17/2003	4.8004	4.80%	4.99%	9/23/1994	7.11%
3/14/2003	4.7062	4.71%	5.00%	9/26/1994	7.12%
3/13/2003	4.7451	4.75%	5.00%	9/27/1994	7.13%
3/12/2003	4.6104	4.61%	5.01%	9/28/1994	7.14%
3/11/2003	4.6437	4.64%	5.01%	9/29/1994	7.15%
3/10/2003	4.641	4.64%	5.02%	9/30/1994	7.15%
3/7/2003	4.6839	4.68%	5.02%	10/3/1994	7.16%
3/6/2003	4.6972	4.70%	5.03%	10/4/1994	7.17%
3/5/2003	4.6635	4.66%	5.03%	10/5/1994	7.18%
3/4/2003	4.6701	4.67%	5.04%	10/6/1994	7.19%
3/3/2003	4.6692	4.67%	5.04%	10/7/1994	7.19%
2/28/2003	4.6692	4.67%	5.05%	10/10/1994	7.20%
2/27/2003	4.7172	4.72%	5.05%	10/11/1994	7.21%
2/26/2003	4.7419	4.74%	5.05%	10/12/1994	7.22%
2/25/2003	4.7781	4.78%	5.06%	10/13/1994	7.22%
2/24/2003	4.8098	4.81%	5.06%	10/14/1994	7.23%
2/21/2003	4.8455	4.85%	5.07%	10/17/1994	7.24%
2/20/2003	4.8089	4.81%	5.07%	10/18/1994	7.25%
2/19/2003	4.8167	4.82%	5.08%	10/19/1994	7.26%
2/18/2003	4.8632	4.86%	5.08%	10/20/1994	7.27%
2/17/2003	4.8827	4.88%	5.09%	10/21/1994	7.27%
2/14/2003	4.8798	4.88%	5.09%	10/24/1994	7.28%
2/13/2003	4.8092	4.81%	5.09%	10/25/1994	7.29%
2/12/2003	4.8439	4.84%	5.10%	10/26/1994	7.30%
2/11/2003	4.8614	4.86%	5.10%	10/27/1994	7.31%
2/10/2003	4.8498	4.85%	5.11%	10/28/1994	7.32%
2/7/2003	4.8063	4.81%	5.11%	10/31/1994	7.33%
2/6/2003	4.8112	4.81%	5.11%	11/1/1994	7.33%
2/5/2003	4.8557	4.86%	5.12%	11/2/1994	7.34%
2/4/2003	4.7892	4.79%	5.12%	11/3/1994	7.35%
2/3/2003	4.8382	4.84%	5.12%	11/4/1994	7.36%
1/31/2003	4.8411	4.84%	5.13%	11/7/1994	7.37%

1/30/2003	4.8684	4.87%	5.13%	11/8/1994	7.38%
1/29/2003	4.9085	4.91%	5.14%	11/9/1994	7.39%
1/28/2003	4.8703	4.87%	5.14%	11/10/1994	7.40%
1/27/2003	4.883	4.88%	5.14%	11/11/1994	7.41%
1/24/2003	4.8616	4.86%	5.15%	11/14/1994	7.42%
1/23/2003	4.885	4.89%	5.15%	11/15/1994	7.42%
1/22/2003	4.8529	4.85%	5.15%	11/16/1994	7.43%
1/21/2003	4.8919	4.89%	5.16%	11/17/1994	7.44%
1/20/2003	4.9223	4.92%	5.16%	11/18/1994	7.45%
1/17/2003	4.9213	4.92%	5.17%	11/21/1994	7.46%
1/16/2003	4.9688	4.97%	5.17%	11/22/1994	7.47%
1/15/2003	4.9609	4.96%	5.17%	11/23/1994	7.47%
1/14/2003	4.9988	5.00%	5.18%	11/24/1994	7.48%
1/13/2003	5.0249	5.02%	5.18%	11/25/1994	7.49%
1/10/2003	5.045	5.05%	5.18%	11/28/1994	7.49%
1/9/2003	5.0714	5.07%	5.19%	11/29/1994	7.50%
1/8/2003	4.9432	4.94%	5.19%	11/30/1994	7.51%
1/7/2003	4.9491	4.95%	5.19%	12/1/1994	7.51%
1/6/2003	4.9749	4.97%	5.20%	12/2/1994	7.52%
1/3/2003	4.9531	4.95%	5.20%	12/5/1994	7.53%
1/2/2003	4.9551	4.96%	5.21%	12/6/1994	7.53%
1/1/2003	4.7792	4.78%	5.21%	12/7/1994	7.54%
12/31/2002	4.778	4.78%	5.22%	12/8/1994	7.54%
12/30/2002	4.7527	4.75%	5.22%	12/9/1994	7.55%
12/27/2002	4.7812	4.78%	5.23%	12/12/1994	7.55%
12/26/2002	4.8572	4.86%	5.23%	12/13/1994	7.56%
12/25/2002	4.8669	4.87%	5.24%	12/14/1994	7.56%
12/24/2002	4.867	4.87%	5.24%	12/15/1994	7.57%
12/23/2002	4.8943	4.89%	5.25%	12/16/1994	7.57%
12/20/2002	4.8933	4.89%	5.25%	12/19/1994	7.58%
12/19/2002	4.8894	4.89%	5.25%	12/20/1994	7.58%
12/18/2002	4.9603	4.96%	5.26%	12/21/1994	7.59%
12/17/2002	5.0191	5.02%	5.26%	12/22/1994	7.59%
12/16/2002	5.0211	5.02%	5.27%	12/23/1994	7.60%
12/13/2002	4.9484	4.95%	5.27%	12/26/1994	7.60%
12/12/2002	4.8925	4.89%	5.27%	12/27/1994	7.61%
12/11/2002	4.8857	4.89%	5.28%	12/28/1994	7.61%
12/10/2002	4.917	4.92%	5.28%	12/29/1994	7.62%
12/9/2002	4.9308	4.93%	5.28%	12/30/1994	7.62%
12/6/2002	4.9773	4.98%	5.29%	1/2/1995	7.62%
12/5/2002	4.9873	4.99%	5.29%	1/3/1995	7.63%
12/4/2002	4.9972	5.00%	5.29%	1/4/1995	7.63%
12/3/2002	5.0323	5.03%	5.29%	1/5/1995	7.64%
12/2/2002	5.0444	5.04%	5.29%	1/6/1995	7.64%
11/29/2002	5.0353	5.04%	5.30%	1/9/1995	7.64%
11/28/2002	5.1073	5.11%	5.30%	1/10/1995	7.64%
11/27/2002	5.1084	5.11%	5.30%	1/11/1995	7.65%

11/26/2002	4.9369	4.94%	5.30%	1/12/1995	7.65%
11/25/2002	5.0244	5.02%	5.30%	1/13/1995	7.65%
11/22/2002	5.0214	5.02%	5.30%	1/16/1995	7.66%
11/21/2002	5.0264	5.03%	5.31%	1/17/1995	7.66%
11/20/2002	4.935	4.94%	5.31%	1/18/1995	7.66%
11/19/2002	4.8502	4.85%	5.31%	1/19/1995	7.66%
11/18/2002	4.8638	4.86%	5.31%	1/20/1995	7.67%
11/15/2002	4.9096	4.91%	5.32%	1/23/1995	7.67%
11/14/2002	4.9539	4.95%	5.32%	1/24/1995	7.67%
11/13/2002	4.788	4.79%	5.32%	1/25/1995	7.68%
11/12/2002	4.7975	4.80%	5.32%	1/26/1995	7.68%
11/11/2002	4.789	4.79%	5.33%	1/27/1995	7.68%
11/8/2002	4.7634	4.76%	5.33%	1/30/1995	7.68%
11/7/2002	4.8854	4.89%	5.33%	1/31/1995	7.69%
11/6/2002	5.0579	5.06%	5.34%	2/1/1995	7.69%
11/5/2002	5.0771	5.08%	5.34%	2/2/1995	7.69%
11/4/2002	5.0589	5.06%	5.34%	2/3/1995	7.69%
11/1/2002	5.0408	5.04%	5.34%	2/6/1995	7.70%
10/31/2002	4.9858	4.99%	5.34%	2/7/1995	7.70%
10/30/2002	5.0268	5.03%	5.35%	2/8/1995	7.70%
10/29/2002	5.0118	5.01%	5.35%	2/9/1995	7.70%
10/28/2002	5.1047	5.10%	5.35%	2/10/1995	7.70%
10/25/2002	5.0833	5.08%	5.35%	2/13/1995	7.70%
10/24/2002	5.0864	5.09%	5.35%	2/14/1995	7.70%
10/23/2002	5.1642	5.16%	5.35%	2/15/1995	7.70%
10/22/2002	5.1539	5.15%	5.35%	2/16/1995	7.70%
10/21/2002	5.1426	5.14%	5.36%	2/17/1995	7.70%
10/18/2002	5.0581	5.06%	5.36%	2/20/1995	7.70%
10/17/2002	5.1089	5.11%	5.36%	2/21/1995	7.70%
10/16/2002	5.006	5.01%	5.36%	2/22/1995	7.71%
10/15/2002	4.9683	4.97%	5.36%	2/23/1995	7.71%
10/14/2002	4.8107	4.81%	5.36%	2/24/1995	7.71%
10/11/2002	4.8041	4.80%	5.37%	2/27/1995	7.71%
10/10/2002	4.7153	4.72%	5.37%	2/28/1995	7.71%
10/9/2002	4.6549	4.65%	5.38%	3/1/1995	7.71%
10/8/2002	4.6958	4.70%	5.38%	3/2/1995	7.71%
10/7/2002	4.7079	4.71%	5.38%	3/3/1995	7.71%
10/4/2002	4.7136	4.71%	5.39%	3/6/1995	7.71%
10/3/2002	4.7334	4.73%	5.39%	3/7/1995	7.71%
10/2/2002	4.7221	4.72%	5.40%	3/8/1995	7.71%
10/1/2002	4.7457	4.75%	5.40%	3/9/1995	7.71%
9/30/2002	4.6682	4.67%	5.40%	3/10/1995	7.72%
9/27/2002	4.6784	4.68%	5.41%	3/13/1995	7.72%
9/26/2002	4.7298	4.73%	5.41%	3/14/1995	7.72%
9/25/2002	4.7186	4.72%	5.42%	3/15/1995	7.72%
9/24/2002	4.6288	4.63%	5.42%	3/16/1995	7.72%
9/23/2002	4.6712	4.67%	5.42%	3/17/1995	7.72%

9/20/2002	4.7422	4.74%	5.43%	3/20/1995	7.72%
9/19/2002	4.7039	4.70%	5.43%	3/21/1995	7.72%
9/18/2002	4.7442	4.74%	5.44%	3/22/1995	7.72%
9/17/2002	4.7273	4.73%	5.44%	3/23/1995	7.72%
9/16/2002	4.7594	4.76%	5.44%	3/24/1995	7.72%
9/13/2002	4.7669	4.77%	5.45%	3/27/1995	7.72%
9/12/2002	4.8146	4.81%	5.45%	3/28/1995	7.72%
9/11/2002	4.8791	4.88%	5.46%	3/29/1995	7.72%
9/10/2002	4.8386	4.84%	5.46%	3/30/1995	7.72%
9/9/2002	4.8685	4.87%	5.46%	3/31/1995	7.72%
9/6/2002	4.8588	4.86%	5.46%	4/3/1995	7.72%
9/5/2002	4.7824	4.78%	5.46%	4/4/1995	7.72%
9/4/2002	4.8024	4.80%	5.47%	4/5/1995	7.72%
9/3/2002	4.81	4.81%	5.47%	4/6/1995	7.71%
9/2/2002	4.928	4.93%	5.47%	4/7/1995	7.71%
8/30/2002	4.9251	4.93%	5.47%	4/10/1995	7.71%
8/29/2002	4.9586	4.96%	5.48%	4/11/1995	7.71%
8/28/2002	5.0191	5.02%	5.48%	4/12/1995	7.71%
8/27/2002	5.0602	5.06%	5.48%	4/13/1995	7.71%
8/26/2002	5.0151	5.02%	5.48%	4/14/1995	7.71%
8/23/2002	5.0321	5.03%	5.48%	4/17/1995	7.71%
8/22/2002	5.0906	5.09%	5.48%	4/18/1995	7.70%
8/21/2002	5.0103	5.01%	5.48%	4/19/1995	7.70%
8/20/2002	4.9667	4.97%	5.48%	4/20/1995	7.70%
8/19/2002	5.0523	5.05%	5.48%	4/21/1995	7.70%
8/16/2002	5.0917	5.09%	5.48%	4/24/1995	7.70%
8/15/2002	4.9757	4.98%	5.48%	4/25/1995	7.70%
8/14/2002	4.9295	4.93%	5.48%	4/26/1995	7.70%
8/13/2002	4.9659	4.97%	5.48%	4/27/1995	7.70%
8/12/2002	5.0666	5.07%	5.48%	4/28/1995	7.70%
8/9/2002	5.1091	5.11%	5.48%	5/1/1995	7.69%
8/8/2002	5.2223	5.22%	5.48%	5/2/1995	7.69%
8/7/2002	5.215	5.22%	5.48%	5/3/1995	7.69%
8/6/2002	5.2286	5.23%	5.47%	5/4/1995	7.69%
8/5/2002	5.1592	5.16%	5.47%	5/5/1995	7.69%
8/2/2002	5.2171	5.22%	5.47%	5/8/1995	7.69%
8/1/2002	5.285	5.29%	5.47%	5/9/1995	7.68%
7/31/2002	5.3011	5.30%	5.47%	5/10/1995	7.68%
7/30/2002	5.3964	5.40%	5.47%	5/11/1995	7.68%
7/29/2002	5.417	5.42%	5.47%	5/12/1995	7.68%
7/26/2002	5.3096	5.31%	5.47%	5/15/1995	7.67%
7/25/2002	5.2968	5.30%	5.47%	5/16/1995	7.67%
7/24/2002	5.3415	5.34%	5.47%	5/17/1995	7.67%
7/23/2002	5.2757	5.28%	5.47%	5/18/1995	7.66%
7/22/2002	5.2789	5.28%	5.47%	5/19/1995	7.66%
7/19/2002	5.3233	5.32%	5.48%	5/22/1995	7.66%
7/18/2002	5.406	5.41%	5.48%	5/23/1995	7.65%

7/17/2002	5.4506	5.45%	5.48%	5/24/1995	7.65%
7/16/2002	5.4484	5.45%	5.48%	5/25/1995	7.65%
7/15/2002	5.38	5.38%	5.48%	5/26/1995	7.64%
7/12/2002	5.3275	5.33%	5.47%	5/29/1995	7.64%
7/11/2002	5.3682	5.37%	5.47%	5/30/1995	7.64%
7/10/2002	5.3361	5.34%	5.47%	5/31/1995	7.63%
7/9/2002	5.4135	5.41%	5.47%	6/1/1995	7.63%
7/8/2002	5.4779	5.48%	5.47%	6/2/1995	7.62%
7/5/2002	5.5244	5.52%	5.47%	6/5/1995	7.62%
7/4/2002	5.4461	5.45%	5.47%	6/6/1995	7.61%
7/3/2002	5.4516	5.45%	5.47%	6/7/1995	7.61%
7/2/2002	5.4363	5.44%	5.47%	6/8/1995	7.60%
7/1/2002	5.4767	5.48%	5.47%	6/9/1995	7.60%
6/28/2002	5.5076	5.51%	5.47%	6/12/1995	7.60%
6/27/2002	5.5142	5.51%	5.47%	6/13/1995	7.59%
6/26/2002	5.4275	5.43%	5.47%	6/14/1995	7.59%
6/25/2002	5.4569	5.46%	5.48%	6/15/1995	7.58%
6/24/2002	5.4536	5.45%	5.48%	6/16/1995	7.58%
6/21/2002	5.3971	5.40%	5.48%	6/19/1995	7.57%
6/20/2002	5.4264	5.43%	5.48%	6/20/1995	7.56%
6/19/2002	5.3863	5.39%	5.48%	6/21/1995	7.56%
6/18/2002	5.4602	5.46%	5.48%	6/22/1995	7.55%
6/17/2002	5.4602	5.46%	5.48%	6/23/1995	7.55%
6/14/2002	5.4111	5.41%	5.47%	6/26/1995	7.54%
6/13/2002	5.492	5.49%	5.47%	6/27/1995	7.53%
6/12/2002	5.5396	5.54%	5.47%	6/28/1995	7.53%
6/11/2002	5.5507	5.55%	5.47%	6/29/1995	7.52%
6/10/2002	5.6057	5.61%	5.47%	6/30/1995	7.52%
6/7/2002	5.6591	5.66%	5.47%	7/3/1995	7.51%
6/6/2002	5.6057	5.61%	5.47%	7/4/1995	7.50%
6/5/2002	5.6567	5.66%	5.47%	7/5/1995	7.50%
6/4/2002	5.6237	5.62%	5.47%	7/6/1995	7.49%
6/3/2002	5.5966	5.60%	5.47%	7/7/1995	7.49%
5/31/2002	5.6147	5.61%	5.47%	7/10/1995	7.48%
5/30/2002	5.5943	5.59%	5.47%	7/11/1995	7.47%
5/29/2002	5.6237	5.62%	5.47%	7/12/1995	7.46%
5/28/2002	5.6635	5.66%	5.46%	7/13/1995	7.46%
5/27/2002	5.6669	5.67%	5.46%	7/14/1995	7.45%
5/24/2002	5.6612	5.66%	5.46%	7/17/1995	7.45%
5/23/2002	5.6657	5.67%	5.46%	7/18/1995	7.44%
5/22/2002	5.6395	5.64%	5.46%	7/19/1995	7.43%
5/21/2002	5.6634	5.66%	5.46%	7/20/1995	7.43%
5/20/2002	5.6966	5.70%	5.46%	7/21/1995	7.43%
5/17/2002	5.7556	5.76%	5.46%	7/24/1995	7.42%
5/16/2002	5.6816	5.68%	5.46%	7/25/1995	7.42%
5/15/2002	5.73	5.73%	5.46%	7/26/1995	7.41%
5/14/2002	5.7428	5.74%	5.46%	7/27/1995	7.40%

5/13/2002	5.685	5.69%	5.45%	7/28/1995	7.40%
5/10/2002	5.5986	5.60%	5.45%	7/31/1995	7.39%
5/9/2002	5.6325	5.63%	5.45%	8/1/1995	7.39%
5/8/2002	5.6701	5.67%	5.45%	8/2/1995	7.38%
5/7/2002	5.5337	5.53%	5.45%	8/3/1995	7.38%
5/6/2002	5.5371	5.54%	5.45%	8/4/1995	7.37%
5/3/2002	5.536	5.54%	5.45%	8/7/1995	7.37%
5/2/2002	5.5862	5.59%	5.45%	8/8/1995	7.36%
5/1/2002	5.5638	5.56%	5.45%	8/9/1995	7.35%
4/30/2002	5.5918	5.59%	5.45%	8/10/1995	7.35%
4/29/2002	5.6256	5.63%	5.45%	8/11/1995	7.34%
4/26/2002	5.5873	5.59%	5.45%	8/14/1995	7.34%
4/25/2002	5.6222	5.62%	5.45%	8/15/1995	7.33%
4/24/2002	5.6233	5.62%	5.45%	8/16/1995	7.32%
4/23/2002	5.6608	5.66%	5.45%	8/17/1995	7.32%
4/22/2002	5.6734	5.67%	5.45%	8/18/1995	7.31%
4/19/2002	5.6837	5.68%	5.45%	8/21/1995	7.31%
4/18/2002	5.699	5.70%	5.45%	8/22/1995	7.30%
4/17/2002	5.73	5.73%	5.45%	8/23/1995	7.29%
4/16/2002	5.663	5.66%	5.45%	8/24/1995	7.29%
4/15/2002	5.618	5.62%	5.45%	8/25/1995	7.28%
4/12/2002	5.647	5.65%	5.45%	8/28/1995	7.27%
4/11/2002	5.671	5.67%	5.45%	8/29/1995	7.27%
4/10/2002	5.701	5.70%	5.45%	8/30/1995	7.26%
4/9/2002	5.669	5.67%	5.45%	8/31/1995	7.25%
4/8/2002	5.713	5.71%	5.45%	9/1/1995	7.25%
4/5/2002	5.666	5.67%	5.45%	9/4/1995	7.24%
4/4/2002	5.711	5.71%	5.45%	9/5/1995	7.23%
4/3/2002	5.719	5.72%	5.45%	9/6/1995	7.23%
4/2/2002	5.762	5.76%	5.45%	9/7/1995	7.22%
4/1/2002	5.829	5.83%	5.45%	9/8/1995	7.21%
3/29/2002	5.795	5.80%	5.45%	9/11/1995	7.20%
3/28/2002	5.799	5.80%	5.45%	9/12/1995	7.20%
3/27/2002	5.757	5.76%	5.45%	9/13/1995	7.19%
3/26/2002	5.756	5.76%	5.45%	9/14/1995	7.18%
3/25/2002	5.803	5.80%	5.45%	9/15/1995	7.18%
3/22/2002	5.812	5.81%	5.45%	9/18/1995	7.17%
3/21/2002	5.789	5.79%	5.45%	9/19/1995	7.16%
3/20/2002	5.821	5.82%	5.44%	9/20/1995	7.16%
3/19/2002	5.733	5.73%	5.44%	9/21/1995	7.15%
3/18/2002	5.735	5.74%	5.44%	9/22/1995	7.14%
3/15/2002	5.76	5.76%	5.44%	9/25/1995	7.14%
3/14/2002	5.834	5.83%	5.44%	9/26/1995	7.13%
3/13/2002	5.746	5.75%	5.44%	9/27/1995	7.12%
3/12/2002	5.724	5.72%	5.44%	9/28/1995	7.12%
3/11/2002	5.719	5.72%	5.44%	9/29/1995	7.11%
3/8/2002	5.717	5.72%	5.44%	10/2/1995	7.10%

3/7/2002	5.662	5.66%	5.44%	10/3/1995	7.10%
3/6/2002	5.547	5.55%	5.44%	10/4/1995	7.09%
3/5/2002	5.487	5.49%	5.44%	10/5/1995	7.08%
3/4/2002	5.502	5.50%	5.45%	10/6/1995	7.08%
3/1/2002	5.504	5.50%	5.45%	10/9/1995	7.07%
2/28/2002	5.417	5.42%	5.45%	10/10/1995	7.06%
2/27/2002	5.372	5.37%	5.45%	10/11/1995	7.06%
2/26/2002	5.425	5.43%	5.45%	10/12/1995	7.05%
2/25/2002	5.366	5.37%	5.46%	10/13/1995	7.04%
2/22/2002	5.344	5.34%	5.46%	10/16/1995	7.03%
2/21/2002	5.367	5.37%	5.46%	10/17/1995	7.02%
2/20/2002	5.389	5.39%	5.46%	10/18/1995	7.02%
2/19/2002	5.388	5.39%	5.46%	10/19/1995	7.01%
2/18/2002	5.369	5.37%	5.47%	10/20/1995	7.00%
2/15/2002	5.366	5.37%	5.47%	10/23/1995	6.99%
2/14/2002	5.41	5.41%	5.47%	10/24/1995	6.99%
2/13/2002	5.454	5.45%	5.47%	10/25/1995	6.98%
2/12/2002	5.456	5.46%	5.47%	10/26/1995	6.97%
2/11/2002	5.404	5.40%	5.47%	10/27/1995	6.97%
2/8/2002	5.375	5.38%	5.48%	10/30/1995	6.96%
2/7/2002	5.41	5.41%	5.48%	10/31/1995	6.95%
2/6/2002	5.373	5.37%	5.48%	11/1/1995	6.94%
2/5/2002	5.342	5.34%	5.48%	11/2/1995	6.93%
2/4/2002	5.348	5.35%	5.48%	11/3/1995	6.93%
2/1/2002	5.393	5.39%	5.49%	11/6/1995	6.92%
1/31/2002	5.431	5.43%	5.49%	11/7/1995	6.91%
1/30/2002	5.434	5.43%	5.49%	11/8/1995	6.90%
1/29/2002	5.387	5.39%	5.49%	11/9/1995	6.90%
1/28/2002	5.467	5.47%	5.49%	11/10/1995	6.89%
1/25/2002	5.467	5.47%	5.49%	11/13/1995	6.88%
1/24/2002	5.444	5.44%	5.50%	11/14/1995	6.88%
1/23/2002	5.47	5.47%	5.50%	11/15/1995	6.87%
1/22/2002	5.384	5.38%	5.50%	11/16/1995	6.86%
1/21/2002	5.36	5.36%	5.50%	11/17/1995	6.86%
1/18/2002	5.358	5.36%	5.50%	11/20/1995	6.85%
1/17/2002	5.4	5.40%	5.50%	11/21/1995	6.84%
1/16/2002	5.347	5.35%	5.50%	11/22/1995	6.84%
1/15/2002	5.337	5.34%	5.50%	11/23/1995	6.83%
1/14/2002	5.379	5.38%	5.50%	11/24/1995	6.82%
1/11/2002	5.371	5.37%	5.50%	11/27/1995	6.82%
1/10/2002	5.416	5.42%	5.51%	11/28/1995	6.81%
1/9/2002	5.497	5.50%	5.51%	11/29/1995	6.80%
1/8/2002	5.529	5.53%	5.51%	11/30/1995	6.80%
1/7/2002	5.488	5.49%	5.51%	12/1/1995	6.79%
1/4/2002	5.548	5.55%	5.51%	12/4/1995	6.78%
1/3/2002	5.534	5.53%	5.51%	12/5/1995	6.77%
1/2/2002	5.556	5.56%	5.50%	12/6/1995	6.77%

1/1/2002	5.472	5.47%	5.50%	12/7/1995	6.76%
12/31/2001	5.466	5.47%	5.50%	12/8/1995	6.75%
12/28/2001	5.535	5.54%	5.50%	12/11/1995	6.74%
12/27/2001	5.472	5.47%	5.50%	12/12/1995	6.74%
12/26/2001	5.539	5.54%	5.50%	12/13/1995	6.73%
12/25/2001	5.49	5.49%	5.50%	12/14/1995	6.72%
12/24/2001	5.488	5.49%	5.50%	12/15/1995	6.72%
12/21/2001	5.442	5.44%	5.50%	12/18/1995	6.71%
12/20/2001	5.413	5.41%	5.50%	12/19/1995	6.70%
12/19/2001	5.448	5.45%	5.50%	12/20/1995	6.70%
12/18/2001	5.512	5.51%	5.49%	12/21/1995	6.69%
12/17/2001	5.567	5.57%	5.49%	12/22/1995	6.68%
12/14/2001	5.585	5.59%	5.49%	12/25/1995	6.68%
12/13/2001	5.509	5.51%	5.49%	12/26/1995	6.67%
12/12/2001	5.476	5.48%	5.49%	12/27/1995	6.66%
12/11/2001	5.539	5.54%	5.49%	12/28/1995	6.66%
12/10/2001	5.558	5.56%	5.49%	12/29/1995	6.65%
12/7/2001	5.584	5.58%	5.49%	1/1/1996	6.64%
12/6/2001	5.461	5.46%	5.49%	1/2/1996	6.63%
12/5/2001	5.355	5.36%	5.49%	1/3/1996	6.63%
12/4/2001	5.206	5.21%	5.49%	1/4/1996	6.62%
12/3/2001	5.243	5.24%	5.49%	1/5/1996	6.61%
11/30/2001	5.286	5.29%	5.49%	1/8/1996	6.61%
11/29/2001	5.237	5.24%	5.49%	1/9/1996	6.60%
11/28/2001	5.352	5.35%	5.49%	1/10/1996	6.59%
11/27/2001	5.333	5.33%	5.49%	1/11/1996	6.59%
11/26/2001	5.381	5.38%	5.49%	1/12/1996	6.58%
11/23/2001	5.36	5.36%	5.49%	1/15/1996	6.58%
11/22/2001	5.355	5.36%	5.49%	1/16/1996	6.57%
11/21/2001	5.355	5.36%	5.49%	1/17/1996	6.56%
11/20/2001	5.318	5.32%	5.49%	1/18/1996	6.56%
11/19/2001	5.237	5.24%	5.49%	1/19/1996	6.55%
11/16/2001	5.268	5.27%	5.49%	1/22/1996	6.54%
11/15/2001	5.221	5.22%	5.50%	1/23/1996	6.54%
11/14/2001	5.027	5.03%	5.50%	1/24/1996	6.53%
11/13/2001	4.921	4.92%	5.50%	1/25/1996	6.52%
11/12/2001	4.876	4.88%	5.50%	1/26/1996	6.52%
11/9/2001	4.873	4.87%	5.51%	1/29/1996	6.51%
11/8/2001	4.864	4.86%	5.51%	1/30/1996	6.50%
11/7/2001	4.791	4.79%	5.51%	1/31/1996	6.50%
11/6/2001	4.846	4.85%	5.52%	2/1/1996	6.49%
11/5/2001	4.857	4.86%	5.52%	2/2/1996	6.49%
11/2/2001	4.956	4.96%	5.52%	2/5/1996	6.48%
11/1/2001	4.803	4.80%	5.53%	2/6/1996	6.47%
10/31/2001	4.874	4.87%	5.53%	2/7/1996	6.47%
10/30/2001	5.205	5.21%	5.54%	2/8/1996	6.46%
10/29/2001	5.262	5.26%	5.54%	2/9/1996	6.46%

10/26/2001	5.271	5.27%	5.54%	2/12/1996	6.45%
10/25/2001	5.297	5.30%	5.54%	2/13/1996	6.45%
10/24/2001	5.339	5.34%	5.54%	2/14/1996	6.44%
10/23/2001	5.389	5.39%	5.54%	2/15/1996	6.44%
10/22/2001	5.384	5.38%	5.54%	2/16/1996	6.44%
10/19/2001	5.358	5.36%	5.54%	2/19/1996	6.43%
10/18/2001	5.318	5.32%	5.55%	2/20/1996	6.43%
10/17/2001	5.314	5.31%	5.55%	2/21/1996	6.43%
10/16/2001	5.343	5.34%	5.55%	2/22/1996	6.43%
10/15/2001	5.371	5.37%	5.55%	2/23/1996	6.42%
10/12/2001	5.426	5.43%	5.55%	2/26/1996	6.42%
10/11/2001	5.401	5.40%	5.55%	2/27/1996	6.42%
10/10/2001	5.365	5.37%	5.55%	2/28/1996	6.42%
10/9/2001	5.376	5.38%	5.55%	2/29/1996	6.42%
10/8/2001	5.312	5.31%	5.55%	3/1/1996	6.41%
10/5/2001	5.308	5.31%	5.55%	3/4/1996	6.41%
10/4/2001	5.302	5.30%	5.55%	3/5/1996	6.41%
10/3/2001	5.293	5.29%	5.55%	3/6/1996	6.41%
10/2/2001	5.322	5.32%	5.55%	3/7/1996	6.41%
10/1/2001	5.373	5.37%	5.55%	3/8/1996	6.41%
9/28/2001	5.421	5.42%	5.55%	3/11/1996	6.41%
9/27/2001	5.435	5.44%	5.55%	3/12/1996	6.41%
9/26/2001	5.502	5.50%	5.55%	3/13/1996	6.41%
9/25/2001	5.568	5.57%	5.55%	3/14/1996	6.41%
9/24/2001	5.576	5.58%	5.55%	3/15/1996	6.41%
9/21/2001	5.583	5.58%	5.55%	3/18/1996	6.41%
9/20/2001	5.623	5.62%	5.55%	3/19/1996	6.41%
9/19/2001	5.551	5.55%	5.55%	3/20/1996	6.41%
9/18/2001	5.542	5.54%	5.55%	3/21/1996	6.41%
9/17/2001	5.423	5.42%	5.55%	3/22/1996	6.41%
9/14/2001	5.35	5.35%	5.55%	3/25/1996	6.41%
9/13/2001	5.392	5.39%	5.55%	3/26/1996	6.41%
9/11/2001	5.416	5.42%	5.55%	3/27/1996	6.41%
9/10/2001	5.437	5.44%	5.55%	3/28/1996	6.42%
9/7/2001	5.369	5.37%	5.55%	3/29/1996	6.42%
9/6/2001	5.413	5.41%	5.55%	4/1/1996	6.42%
9/5/2001	5.479	5.48%	5.56%	4/2/1996	6.42%
9/4/2001	5.483	5.48%	5.56%	4/3/1996	6.42%
9/3/2001	5.369	5.37%	5.56%	4/4/1996	6.42%
8/31/2001	5.368	5.37%	5.56%	4/5/1996	6.42%
8/30/2001	5.385	5.39%	5.56%	4/8/1996	6.42%
8/29/2001	5.362	5.36%	5.56%	4/9/1996	6.42%
8/28/2001	5.405	5.41%	5.56%	4/10/1996	6.42%
8/27/2001	5.463	5.46%	5.57%	4/11/1996	6.43%
8/24/2001	5.449	5.45%	5.57%	4/12/1996	6.43%
8/23/2001	5.412	5.41%	5.57%	4/15/1996	6.43%
8/22/2001	5.435	5.44%	5.57%	4/16/1996	6.43%

8/21/2001	5.432	5.43%	5.57%	4/17/1996	6.43%
8/20/2001	5.453	5.45%	5.57%	4/18/1996	6.43%
8/17/2001	5.42	5.42%	5.58%	4/19/1996	6.43%
8/16/2001	5.477	5.48%	5.58%	4/22/1996	6.43%
8/15/2001	5.517	5.52%	5.58%	4/23/1996	6.43%
8/14/2001	5.506	5.51%	5.58%	4/24/1996	6.43%
8/13/2001	5.512	5.51%	5.58%	4/25/1996	6.43%
8/10/2001	5.504	5.50%	5.59%	4/26/1996	6.43%
8/9/2001	5.534	5.53%	5.59%	4/29/1996	6.43%
8/8/2001	5.507	5.51%	5.59%	4/30/1996	6.43%
8/7/2001	5.599	5.60%	5.59%	5/1/1996	6.43%
8/6/2001	5.592	5.59%	5.59%	5/2/1996	6.43%
8/3/2001	5.585	5.59%	5.59%	5/3/1996	6.43%
8/2/2001	5.578	5.58%	5.59%	5/6/1996	6.44%
8/1/2001	5.526	5.53%	5.59%	5/7/1996	6.44%
7/31/2001	5.522	5.52%	5.59%	5/8/1996	6.44%
7/30/2001	5.514	5.51%	5.59%	5/9/1996	6.44%
7/27/2001	5.543	5.54%	5.60%	5/10/1996	6.44%
7/26/2001	5.571	5.57%	5.60%	5/13/1996	6.44%
7/25/2001	5.597	5.60%	5.60%	5/14/1996	6.44%
7/24/2001	5.528	5.53%	5.60%	5/15/1996	6.44%
7/23/2001	5.527	5.53%	5.60%	5/16/1996	6.44%
7/20/2001	5.549	5.55%	5.60%	5/17/1996	6.44%
7/19/2001	5.527	5.53%	5.60%	5/20/1996	6.44%
7/18/2001	5.516	5.52%	5.60%	5/21/1996	6.44%
7/17/2001	5.599	5.60%	5.61%	5/22/1996	6.43%
7/16/2001	5.579	5.58%	5.61%	5/23/1996	6.43%
7/13/2001	5.619	5.62%	5.61%	5/24/1996	6.43%
7/12/2001	5.649	5.65%	5.61%	5/27/1996	6.43%
7/11/2001	5.684	5.68%	5.61%	5/28/1996	6.43%
7/10/2001	5.67	5.67%	5.61%	5/29/1996	6.43%
7/9/2001	5.694	5.69%	5.61%	5/30/1996	6.43%
7/6/2001	5.732	5.73%	5.61%	5/31/1996	6.44%
7/5/2001	5.74	5.74%	5.62%	6/3/1996	6.44%
7/4/2001	5.725	5.73%	5.62%	6/4/1996	6.44%
7/3/2001	5.719	5.72%	5.62%	6/5/1996	6.44%
7/2/2001	5.687	5.69%	5.62%	6/6/1996	6.44%
6/29/2001	5.759	5.76%	5.62%	6/7/1996	6.44%
6/28/2001	5.671	5.67%	5.62%	6/10/1996	6.45%
6/27/2001	5.618	5.62%	5.62%	6/11/1996	6.45%
6/26/2001	5.652	5.65%	5.62%	6/12/1996	6.45%
6/25/2001	5.587	5.59%	5.62%	6/13/1996	6.45%
6/22/2001	5.575	5.58%	5.63%	6/14/1996	6.46%
6/21/2001	5.623	5.62%	5.63%	6/17/1996	6.46%
6/20/2001	5.665	5.67%	5.63%	6/18/1996	6.46%
6/19/2001	5.689	5.69%	5.63%	6/19/1996	6.47%
6/18/2001	5.701	5.70%	5.63%	6/20/1996	6.47%

6/15/2001	5.677	5.68%	5.63%	6/21/1996	6.47%
6/14/2001	5.642	5.64%	5.63%	6/24/1996	6.47%
6/13/2001	5.662	5.66%	5.63%	6/25/1996	6.48%
6/12/2001	5.652	5.65%	5.63%	6/26/1996	6.48%
6/11/2001	5.683	5.68%	5.63%	6/27/1996	6.48%
6/8/2001	5.737	5.74%	5.63%	6/28/1996	6.48%
6/7/2001	5.729	5.73%	5.63%	7/1/1996	6.49%
6/6/2001	5.647	5.65%	5.63%	7/2/1996	6.49%
6/5/2001	5.653	5.65%	5.63%	7/3/1996	6.49%
6/4/2001	5.692	5.69%	5.63%	7/4/1996	6.49%
6/1/2001	5.705	5.71%	5.63%	7/5/1996	6.49%
5/31/2001	5.753	5.75%	5.63%	7/8/1996	6.50%
5/30/2001	5.842	5.84%	5.63%	7/9/1996	6.50%
5/29/2001	5.86	5.86%	5.63%	7/10/1996	6.50%
5/28/2001	5.854	5.85%	5.63%	7/11/1996	6.51%
5/25/2001	5.853	5.85%	5.63%	7/12/1996	6.51%
5/24/2001	5.846	5.85%	5.62%	7/15/1996	6.51%
5/23/2001	5.799	5.80%	5.62%	7/16/1996	6.52%
5/22/2001	5.778	5.78%	5.62%	7/17/1996	6.52%
5/21/2001	5.738	5.74%	5.62%	7/18/1996	6.52%
5/18/2001	5.767	5.77%	5.62%	7/19/1996	6.53%
5/17/2001	5.763	5.76%	5.62%	7/22/1996	6.53%
5/16/2001	5.853	5.85%	5.62%	7/23/1996	6.53%
5/15/2001	5.911	5.91%	5.62%	7/24/1996	6.54%
5/14/2001	5.842	5.84%	5.62%	7/25/1996	6.54%
5/11/2001	5.854	5.85%	5.62%	7/26/1996	6.54%
5/10/2001	5.762	5.76%	5.62%	7/29/1996	6.55%
5/9/2001	5.668	5.67%	5.62%	7/30/1996	6.55%
5/8/2001	5.738	5.74%	5.62%	7/31/1996	6.55%
5/7/2001	5.669	5.67%	5.62%	8/1/1996	6.56%
5/4/2001	5.676	5.68%	5.62%	8/2/1996	6.56%
5/3/2001	5.639	5.64%	5.62%	8/5/1996	6.56%
5/2/2001	5.702	5.70%	5.62%	8/6/1996	6.56%
5/1/2001	5.742	5.74%	5.62%	8/7/1996	6.56%
4/30/2001	5.788	5.79%	5.62%	8/8/1996	6.57%
4/27/2001	5.8	5.80%	5.62%	8/9/1996	6.57%
4/26/2001	5.711	5.71%	5.62%	8/12/1996	6.57%
4/25/2001	5.767	5.77%	5.62%	8/13/1996	6.57%
4/24/2001	5.758	5.76%	5.63%	8/14/1996	6.58%
4/23/2001	5.719	5.72%	5.63%	8/15/1996	6.58%
4/20/2001	5.797	5.80%	5.63%	8/16/1996	6.58%
4/19/2001	5.79	5.79%	5.63%	8/19/1996	6.58%
4/18/2001	5.658	5.66%	5.63%	8/20/1996	6.59%
4/17/2001	5.665	5.67%	5.63%	8/21/1996	6.59%
4/16/2001	5.683	5.68%	5.63%	8/22/1996	6.59%
4/13/2001	5.603	5.60%	5.63%	8/23/1996	6.60%
4/12/2001	5.613	5.61%	5.63%	8/26/1996	6.60%

4/11/2001	5.615	5.62%	5.63%	8/27/1996	6.60%
4/10/2001	5.627	5.63%	5.63%	8/28/1996	6.61%
4/9/2001	5.514	5.51%	5.64%	8/29/1996	6.61%
4/6/2001	5.464	5.46%	5.64%	8/30/1996	6.61%
4/5/2001	5.527	5.53%	5.64%	9/2/1996	6.62%
4/4/2001	5.476	5.48%	5.64%	9/3/1996	6.62%
4/3/2001	5.466	5.47%	5.64%	9/4/1996	6.63%
4/2/2001	5.488	5.49%	5.65%	9/5/1996	6.63%
3/30/2001	5.444	5.44%	5.65%	9/6/1996	6.64%
3/29/2001	5.496	5.50%	5.65%	9/9/1996	6.64%
3/28/2001	5.464	5.46%	5.65%	9/10/1996	6.65%
3/27/2001	5.459	5.46%	5.66%	9/11/1996	6.65%
3/26/2001	5.365	5.37%	5.66%	9/12/1996	6.66%
3/23/2001	5.314	5.31%	5.66%	9/13/1996	6.66%
3/22/2001	5.271	5.27%	5.66%	9/16/1996	6.67%
3/21/2001	5.283	5.28%	5.67%	9/17/1996	6.67%
3/20/2001	5.26	5.26%	5.67%	9/18/1996	6.68%
3/19/2001	5.291	5.29%	5.67%	9/19/1996	6.68%
3/16/2001	5.271	5.27%	5.68%	9/20/1996	6.69%
3/15/2001	5.268	5.27%	5.68%	9/23/1996	6.69%
3/14/2001	5.268	5.27%	5.68%	9/24/1996	6.70%
3/13/2001	5.322	5.32%	5.69%	9/25/1996	6.70%
3/12/2001	5.297	5.30%	5.69%	9/26/1996	6.70%
3/9/2001	5.322	5.32%	5.69%	9/27/1996	6.71%
3/8/2001	5.301	5.30%	5.70%	9/30/1996	6.71%
3/7/2001	5.311	5.31%	5.70%	10/1/1996	6.72%
3/6/2001	5.381	5.38%	5.70%	10/2/1996	6.72%
3/5/2001	5.375	5.38%	5.71%	10/3/1996	6.72%
3/2/2001	5.367	5.37%	5.71%	10/4/1996	6.73%
3/1/2001	5.293	5.29%	5.72%	10/7/1996	6.73%
2/28/2001	5.314	5.31%	5.72%	10/8/1996	6.74%
2/27/2001	5.352	5.35%	5.72%	10/9/1996	6.74%
2/26/2001	5.428	5.43%	5.73%	10/10/1996	6.75%
2/23/2001	5.478	5.48%	5.73%	10/11/1996	6.75%
2/22/2001	5.528	5.53%	5.74%	10/14/1996	6.75%
2/21/2001	5.487	5.49%	5.74%	10/15/1996	6.76%
2/20/2001	5.459	5.46%	5.74%	10/16/1996	6.76%
2/19/2001	5.456	5.46%	5.75%	10/17/1996	6.76%
2/16/2001	5.454	5.45%	5.75%	10/18/1996	6.77%
2/15/2001	5.487	5.49%	5.75%	10/21/1996	6.77%
2/14/2001	5.457	5.46%	5.76%	10/22/1996	6.77%
2/13/2001	5.412	5.41%	5.76%	10/23/1996	6.78%
2/12/2001	5.416	5.42%	5.76%	10/24/1996	6.78%
2/9/2001	5.389	5.39%	5.77%	10/25/1996	6.79%
2/8/2001	5.529	5.53%	5.77%	10/28/1996	6.79%
2/7/2001	5.55	5.55%	5.77%	10/29/1996	6.79%
2/6/2001	5.501	5.50%	5.78%	10/30/1996	6.80%

2/5/2001	5.49	5.49%	5.78%	10/31/1996	6.80%
2/2/2001	5.509	5.51%	5.78%	11/1/1996	6.80%
2/1/2001	5.46	5.46%	5.78%	11/4/1996	6.81%
1/31/2001	5.501	5.50%	5.79%	11/5/1996	6.81%
1/30/2001	5.593	5.59%	5.79%	11/6/1996	6.81%
1/29/2001	5.687	5.69%	5.79%	11/7/1996	6.81%
1/26/2001	5.64	5.64%	5.79%	11/8/1996	6.82%
1/25/2001	5.592	5.59%	5.79%	11/11/1996	6.82%
1/24/2001	5.659	5.66%	5.79%	11/12/1996	6.82%
1/23/2001	5.652	5.65%	5.79%	11/13/1996	6.82%
1/22/2001	5.603	5.60%	5.79%	11/14/1996	6.82%
1/19/2001	5.553	5.55%	5.79%	11/15/1996	6.82%
1/18/2001	5.475	5.48%	5.80%	11/18/1996	6.83%
1/17/2001	5.524	5.52%	5.80%	11/19/1996	6.83%
1/16/2001	5.596	5.60%	5.80%	11/20/1996	6.83%
1/12/2001	5.618	5.62%	5.80%	11/21/1996	6.83%
1/11/2001	5.54	5.54%	5.80%	11/22/1996	6.83%
1/10/2001	5.499	5.50%	5.80%	11/25/1996	6.83%
1/9/2001	5.429	5.43%	5.80%	11/26/1996	6.83%
1/8/2001	5.447	5.45%	5.80%	11/27/1996	6.83%
1/5/2001	5.398	5.40%	5.81%	11/28/1996	6.83%
1/4/2001	5.441	5.44%	5.81%	11/29/1996	6.83%
1/3/2001	5.5	5.50%	5.81%	12/2/1996	6.83%
1/2/2001	5.342	5.34%	5.81%	12/3/1996	6.83%
1/1/2001	5.458	5.46%	5.82%	12/4/1996	6.83%
12/29/2000	5.457	5.46%	5.82%	12/5/1996	6.83%
12/28/2000	5.444	5.44%	5.82%	12/6/1996	6.83%
12/27/2000	5.452	5.45%	5.82%	12/9/1996	6.83%
12/26/2000	5.432	5.43%	5.83%	12/10/1996	6.83%
12/25/2000	5.393	5.39%	5.83%	12/11/1996	6.83%
12/22/2000	5.402	5.40%	5.83%	12/12/1996	6.84%
12/21/2000	5.407	5.41%	5.84%	12/13/1996	6.83%
12/20/2000	5.4	5.40%	5.84%	12/16/1996	6.83%
12/19/2000	5.473	5.47%	5.84%	12/17/1996	6.83%
12/18/2000	5.442	5.44%	5.85%	12/18/1996	6.83%
12/15/2000	5.419	5.42%	5.85%	12/19/1996	6.83%
12/14/2000	5.437	5.44%	5.85%	12/20/1996	6.83%
12/13/2000	5.467	5.47%	5.86%	12/23/1996	6.83%
12/12/2000	5.53	5.53%	5.86%	12/24/1996	6.83%
12/11/2000	5.546	5.55%	5.86%	12/25/1996	6.83%
12/8/2000	5.502	5.50%	5.87%	12/26/1996	6.83%
12/7/2000	5.508	5.51%	5.87%	12/27/1996	6.83%
12/6/2000	5.525	5.53%	5.87%	12/30/1996	6.83%
12/5/2000	5.586	5.59%	5.88%	12/31/1996	6.83%
12/4/2000	5.693	5.69%	5.88%	1/1/1997	6.83%
12/1/2000	5.635	5.64%	5.88%	1/2/1997	6.83%
11/30/2000	5.608	5.61%	5.88%	1/3/1997	6.83%

11/29/2000	5.641	5.64%	5.89%	1/6/1997	6.83%
11/28/2000	5.675	5.68%	5.89%	1/7/1997	6.83%
11/27/2000	5.696	5.70%	5.89%	1/8/1997	6.83%
11/24/2000	5.667	5.67%	5.89%	1/9/1997	6.83%
11/23/2000	5.675	5.68%	5.90%	1/10/1997	6.83%
11/22/2000	5.656	5.66%	5.90%	1/13/1997	6.83%
11/21/2000	5.728	5.73%	5.90%	1/14/1997	6.83%
11/20/2000	5.754	5.75%	5.90%	1/15/1997	6.83%
11/17/2000	5.776	5.78%	5.91%	1/16/1997	6.83%
11/16/2000	5.741	5.74%	5.91%	1/17/1997	6.83%
11/15/2000	5.766	5.77%	5.91%	1/20/1997	6.83%
11/14/2000	5.819	5.82%	5.92%	1/21/1997	6.83%
11/13/2000	5.838	5.84%	5.92%	1/22/1997	6.83%
11/10/2000	5.869	5.87%	5.92%	1/23/1997	6.83%
11/9/2000	5.867	5.87%	5.92%	1/24/1997	6.83%
11/8/2000	5.873	5.87%	5.92%	1/27/1997	6.84%
11/7/2000	5.894	5.89%	5.93%	1/28/1997	6.84%
11/6/2000	5.885	5.89%	5.93%	1/29/1997	6.84%
11/3/2000	5.859	5.86%	5.93%	1/30/1997	6.84%
11/2/2000	5.785	5.79%	5.94%	1/31/1997	6.84%
11/1/2000	5.78	5.78%	5.94%	2/3/1997	6.84%
10/31/2000	5.788	5.79%	5.94%	2/4/1997	6.84%
10/30/2000	5.758	5.76%	5.95%	2/5/1997	6.83%
10/27/2000	5.741	5.74%	5.95%	2/6/1997	6.83%
10/26/2000	5.735	5.74%	5.96%	2/7/1997	6.83%
10/25/2000	5.746	5.75%	5.96%	2/10/1997	6.83%
10/24/2000	5.705	5.71%	5.97%	2/11/1997	6.83%
10/23/2000	5.682	5.68%	5.97%	2/12/1997	6.83%
10/20/2000	5.727	5.73%	5.98%	2/13/1997	6.82%
10/19/2000	5.75	5.75%	5.98%	2/14/1997	6.82%
10/18/2000	5.77	5.77%	5.99%	2/17/1997	6.82%
10/17/2000	5.767	5.77%	5.99%	2/18/1997	6.82%
10/16/2000	5.807	5.81%	6.00%	2/19/1997	6.82%
10/13/2000	5.804	5.80%	6.00%	2/20/1997	6.82%
10/12/2000	5.811	5.81%	6.00%	2/21/1997	6.82%
10/11/2000	5.823	5.82%	6.01%	2/24/1997	6.81%
10/10/2000	5.806	5.81%	6.01%	2/25/1997	6.81%
10/9/2000	5.846	5.85%	6.01%	2/26/1997	6.81%
10/6/2000	5.837	5.84%	6.02%	2/27/1997	6.81%
10/5/2000	5.892	5.89%	6.02%	2/28/1997	6.81%
10/4/2000	5.937	5.94%	6.02%	3/3/1997	6.81%
10/3/2000	5.94	5.94%	6.03%	3/4/1997	6.81%
10/2/2000	5.923	5.92%	6.03%	3/5/1997	6.81%
9/29/2000	5.885	5.89%	6.03%	3/6/1997	6.81%
9/28/2000	5.882	5.88%	6.03%	3/7/1997	6.81%
9/27/2000	5.9	5.90%	6.04%	3/10/1997	6.81%
9/26/2000	5.854	5.85%	6.04%	3/11/1997	6.81%

9/25/2000	5.895	5.90%	6.04%	3/12/1997	6.81%
9/22/2000	5.913	5.91%	6.05%	3/13/1997	6.81%
9/21/2000	5.893	5.89%	6.05%	3/14/1997	6.81%
9/20/2000	5.961	5.96%	6.05%	3/17/1997	6.81%
9/19/2000	5.908	5.91%	6.05%	3/18/1997	6.81%
9/18/2000	5.952	5.95%	6.05%	3/19/1997	6.81%
9/15/2000	5.9	5.90%	6.05%	3/20/1997	6.81%
9/14/2000	5.815	5.82%	6.06%	3/21/1997	6.80%
9/13/2000	5.731	5.73%	6.06%	3/24/1997	6.80%
9/12/2000	5.751	5.75%	6.06%	3/25/1997	6.80%
9/11/2000	5.725	5.73%	6.06%	3/26/1997	6.80%
9/8/2000	5.7	5.70%	6.07%	3/27/1997	6.80%
9/7/2000	5.715	5.72%	6.07%	3/28/1997	6.80%
9/6/2000	5.707	5.71%	6.07%	3/31/1997	6.80%
9/5/2000	5.667	5.67%	6.07%	4/1/1997	6.80%
9/4/2000	5.665	5.67%	6.08%	4/2/1997	6.80%
9/1/2000	5.661	5.66%	6.08%	4/3/1997	6.80%
8/31/2000	5.668	5.67%	6.08%	4/4/1997	6.80%
8/30/2000	5.733	5.73%	6.09%	4/7/1997	6.81%
8/29/2000	5.747	5.75%	6.09%	4/8/1997	6.81%
8/28/2000	5.723	5.72%	6.09%	4/9/1997	6.81%
8/25/2000	5.669	5.67%	6.09%	4/10/1997	6.81%
8/24/2000	5.657	5.66%	6.09%	4/11/1997	6.81%
8/23/2000	5.671	5.67%	6.10%	4/14/1997	6.81%
8/22/2000	5.712	5.71%	6.10%	4/15/1997	6.81%
8/21/2000	5.708	5.71%	6.10%	4/16/1997	6.81%
8/18/2000	5.69	5.69%	6.10%	4/17/1997	6.81%
8/17/2000	5.712	5.71%	6.10%	4/18/1997	6.81%
8/16/2000	5.742	5.74%	6.11%	4/21/1997	6.81%
8/15/2000	5.709	5.71%	6.11%	4/22/1997	6.81%
8/14/2000	5.69	5.69%	6.11%	4/23/1997	6.81%
8/11/2000	5.706	5.71%	6.11%	4/24/1997	6.81%
8/10/2000	5.681	5.68%	6.11%	4/25/1997	6.81%
8/9/2000	5.725	5.73%	6.12%	4/28/1997	6.81%
8/8/2000	5.731	5.73%	6.12%	4/29/1997	6.81%
8/7/2000	5.752	5.75%	6.12%	4/30/1997	6.81%
8/4/2000	5.708	5.71%	6.12%	5/1/1997	6.81%
8/3/2000	5.737	5.74%	6.12%	5/2/1997	6.81%
8/2/2000	5.759	5.76%	6.13%	5/5/1997	6.81%
8/1/2000	5.727	5.73%	6.13%	5/6/1997	6.81%
7/31/2000	5.782	5.78%	6.13%	5/7/1997	6.81%
7/28/2000	5.785	5.79%	6.14%	5/8/1997	6.81%
7/27/2000	5.771	5.77%	6.14%	5/9/1997	6.81%
7/26/2000	5.807	5.81%	6.14%	5/12/1997	6.81%
7/25/2000	5.807	5.81%	6.15%	5/13/1997	6.81%
7/24/2000	5.815	5.82%	6.15%	5/14/1997	6.81%
7/21/2000	5.789	5.79%	6.15%	5/15/1997	6.81%

7/20/2000	5.809	5.81%	6.15%	5/16/1997	6.81%
7/19/2000	5.913	5.91%	6.16%	5/19/1997	6.81%
7/18/2000	5.908	5.91%	6.16%	5/20/1997	6.81%
7/17/2000	5.915	5.92%	6.16%	5/21/1997	6.81%
7/14/2000	5.876	5.88%	6.16%	5/22/1997	6.82%
7/13/2000	5.816	5.82%	6.16%	5/23/1997	6.82%
7/12/2000	5.878	5.88%	6.16%	5/26/1997	6.82%
7/11/2000	5.885	5.89%	6.16%	5/27/1997	6.82%
7/10/2000	5.886	5.89%	6.17%	5/28/1997	6.82%
7/7/2000	5.869	5.87%	6.17%	5/29/1997	6.82%
7/6/2000	5.908	5.91%	6.17%	5/30/1997	6.82%
7/5/2000	5.857	5.86%	6.17%	6/2/1997	6.82%
7/3/2000	5.867	5.87%	6.17%	6/3/1997	6.82%
6/30/2000	5.896	5.90%	6.17%	6/4/1997	6.82%
6/29/2000	5.875	5.88%	6.17%	6/5/1997	6.82%
6/28/2000	5.952	5.95%	6.17%	6/6/1997	6.82%
6/27/2000	5.933	5.93%	6.17%	6/9/1997	6.81%
6/26/2000	5.979	5.98%	6.17%	6/10/1997	6.81%
6/23/2000	6.041	6.04%	6.17%	6/11/1997	6.81%
6/22/2000	5.962	5.96%	6.17%	6/12/1997	6.81%
6/21/2000	5.967	5.97%	6.17%	6/13/1997	6.81%
6/20/2000	5.896	5.90%	6.17%	6/16/1997	6.81%
6/19/2000	5.891	5.89%	6.18%	6/17/1997	6.80%
6/16/2000	5.869	5.87%	6.18%	6/18/1997	6.80%
6/15/2000	5.923	5.92%	6.18%	6/19/1997	6.80%
6/14/2000	5.91	5.91%	6.18%	6/20/1997	6.80%
6/13/2000	5.949	5.95%	6.18%	6/23/1997	6.80%
6/12/2000	5.871	5.87%	6.18%	6/24/1997	6.80%
6/9/2000	5.895	5.90%	6.18%	6/25/1997	6.79%
6/8/2000	5.886	5.89%	6.18%	6/26/1997	6.79%
6/7/2000	5.907	5.91%	6.18%	6/27/1997	6.79%
6/6/2000	5.908	5.91%	6.18%	6/30/1997	6.79%
6/5/2000	5.915	5.92%	6.18%	7/1/1997	6.79%
6/2/2000	5.945	5.95%	6.18%	7/2/1997	6.79%
6/1/2000	5.943	5.94%	6.18%	7/3/1997	6.79%
5/31/2000	6.008	6.01%	6.18%	7/4/1997	6.79%
5/30/2000	6.092	6.09%	6.18%	7/7/1997	6.78%
5/29/2000	6.06	6.06%	6.18%	7/8/1997	6.78%
5/26/2000	6.059	6.06%	6.18%	7/9/1997	6.78%
5/25/2000	6.106	6.11%	6.18%	7/10/1997	6.78%
5/24/2000	6.193	6.19%	6.18%	7/11/1997	6.78%
5/23/2000	6.16	6.16%	6.18%	7/14/1997	6.78%
5/22/2000	6.185	6.19%	6.18%	7/15/1997	6.78%
5/19/2000	6.206	6.21%	6.18%	7/16/1997	6.77%
5/18/2000	6.227	6.23%	6.18%	7/17/1997	6.77%
5/17/2000	6.184	6.18%	6.18%	7/18/1997	6.77%
5/16/2000	6.113	6.11%	6.18%	7/21/1997	6.77%

5/15/2000	6.154	6.15%	6.18%	7/22/1997	6.77%
5/12/2000	6.201	6.20%	6.18%	7/23/1997	6.77%
5/11/2000	6.146	6.15%	6.18%	7/24/1997	6.76%
5/10/2000	6.149	6.15%	6.18%	7/25/1997	6.76%
5/9/2000	6.213	6.21%	6.18%	7/28/1997	6.76%
5/8/2000	6.243	6.24%	6.18%	7/29/1997	6.76%
5/5/2000	6.188	6.19%	6.18%	7/30/1997	6.75%
5/4/2000	6.155	6.16%	6.18%	7/31/1997	6.75%
5/3/2000	6.116	6.12%	6.18%	8/1/1997	6.75%
5/2/2000	6.011	6.01%	6.18%	8/4/1997	6.75%
5/1/2000	5.988	5.99%	6.18%	8/5/1997	6.75%
4/28/2000	5.96	5.96%	6.18%	8/6/1997	6.75%
4/27/2000	5.985	5.99%	6.18%	8/7/1997	6.75%
4/26/2000	5.944	5.94%	6.18%	8/8/1997	6.75%
4/25/2000	5.936	5.94%	6.18%	8/11/1997	6.75%
4/24/2000	5.875	5.88%	6.18%	8/12/1997	6.75%
4/21/2000	5.827	5.83%	6.18%	8/13/1997	6.75%
4/20/2000	5.83	5.83%	6.18%	8/14/1997	6.75%
4/19/2000	5.847	5.85%	6.18%	8/15/1997	6.75%
4/18/2000	5.91	5.91%	6.18%	8/18/1997	6.75%
4/17/2000	5.932	5.93%	6.18%	8/19/1997	6.75%
4/14/2000	5.776	5.78%	6.18%	8/20/1997	6.75%
4/13/2000	5.792	5.79%	6.18%	8/21/1997	6.75%
4/12/2000	5.813	5.81%	6.18%	8/22/1997	6.75%
4/11/2000	5.77	5.77%	6.18%	8/25/1997	6.75%
4/10/2000	5.668	5.67%	6.18%	8/26/1997	6.75%
4/7/2000	5.709	5.71%	6.18%	8/27/1997	6.75%
4/6/2000	5.794	5.79%	6.19%	8/28/1997	6.75%
4/5/2000	5.778	5.78%	6.19%	8/29/1997	6.75%
4/4/2000	5.773	5.77%	6.19%	9/1/1997	6.75%
4/3/2000	5.812	5.81%	6.19%	9/2/1997	6.76%
3/31/2000	5.828	5.83%	6.19%	9/3/1997	6.76%
3/30/2000	5.878	5.88%	6.19%	9/4/1997	6.76%
3/29/2000	5.974	5.97%	6.19%	9/5/1997	6.76%
3/28/2000	5.977	5.98%	6.20%	9/8/1997	6.76%
3/27/2000	5.978	5.98%	6.20%	9/9/1997	6.76%
3/24/2000	5.986	5.99%	6.20%	9/10/1997	6.76%
3/23/2000	5.907	5.91%	6.20%	9/11/1997	6.76%
3/22/2000	5.958	5.96%	6.20%	9/12/1997	6.76%
3/21/2000	5.969	5.97%	6.20%	9/15/1997	6.76%
3/20/2000	6.004	6.00%	6.20%	9/16/1997	6.76%
3/17/2000	6	6.00%	6.20%	9/17/1997	6.76%
3/16/2000	6.043	6.04%	6.20%	9/18/1997	6.76%
3/15/2000	6.079	6.08%	6.20%	9/19/1997	6.76%
3/14/2000	6.09	6.09%	6.20%	9/22/1997	6.76%
3/13/2000	6.17	6.17%	6.20%	9/23/1997	6.76%
3/10/2000	6.176	6.18%	6.20%	9/24/1997	6.76%

3/9/2000	6.152	6.15%	6.20%	9/25/1997	6.76%
3/8/2000	6.161	6.16%	6.19%	9/26/1997	6.75%
3/7/2000	6.145	6.15%	6.19%	9/29/1997	6.75%
3/6/2000	6.143	6.14%	6.19%	9/30/1997	6.75%
3/3/2000	6.132	6.13%	6.19%	10/1/1997	6.75%
3/2/2000	6.132	6.13%	6.19%	10/2/1997	6.75%
3/1/2000	6.158	6.16%	6.19%	10/3/1997	6.75%
2/29/2000	6.14	6.14%	6.19%	10/6/1997	6.75%
2/28/2000	6.187	6.19%	6.18%	10/7/1997	6.74%
2/25/2000	6.129	6.13%	6.18%	10/8/1997	6.74%
2/24/2000	6.137	6.14%	6.18%	10/9/1997	6.74%
2/23/2000	6.126	6.13%	6.18%	10/10/1997	6.74%
2/22/2000	6.086	6.09%	6.18%	10/13/1997	6.74%
2/21/2000	6.159	6.16%	6.18%	10/14/1997	6.74%
2/18/2000	6.158	6.16%	6.17%	10/15/1997	6.73%
2/17/2000	6.218	6.22%	6.17%	10/16/1997	6.73%
2/16/2000	6.265	6.27%	6.17%	10/17/1997	6.73%
2/15/2000	6.246	6.25%	6.17%	10/20/1997	6.73%
2/14/2000	6.227	6.23%	6.17%	10/21/1997	6.73%
2/11/2000	6.269	6.27%	6.16%	10/22/1997	6.72%
2/10/2000	6.429	6.43%	6.16%	10/23/1997	6.72%
2/9/2000	6.314	6.31%	6.16%	10/24/1997	6.72%
2/8/2000	6.231	6.23%	6.16%	10/27/1997	6.72%
2/7/2000	6.342	6.34%	6.15%	10/28/1997	6.71%
2/4/2000	6.271	6.27%	6.15%	10/29/1997	6.71%
2/3/2000	6.136	6.14%	6.15%	10/30/1997	6.71%
2/2/2000	6.284	6.28%	6.14%	10/31/1997	6.70%
2/1/2000	6.423	6.42%	6.14%	11/3/1997	6.70%
1/31/2000	6.491	6.49%	6.14%	11/4/1997	6.70%
1/28/2000	6.452	6.45%	6.13%	11/5/1997	6.69%
1/27/2000	6.519	6.52%	6.13%	11/6/1997	6.69%
1/26/2000	6.571	6.57%	6.12%	11/7/1997	6.69%
1/25/2000	6.634	6.63%	6.12%	11/10/1997	6.68%
1/24/2000	6.65	6.65%	6.11%	11/11/1997	6.68%
1/21/2000	6.695	6.70%	6.11%	11/12/1997	6.68%
1/20/2000	6.747	6.75%	6.10%	11/13/1997	6.67%
1/19/2000	6.717	6.72%	6.09%	11/14/1997	6.67%
1/18/2000	6.747	6.75%	6.09%	11/17/1997	6.67%
1/17/2000	6.689	6.69%	6.08%	11/18/1997	6.66%
1/14/2000	6.697	6.70%	6.08%	11/19/1997	6.66%
1/13/2000	6.653	6.65%	6.07%	11/20/1997	6.66%
1/12/2000	6.719	6.72%	6.06%	11/21/1997	6.65%
1/11/2000	6.671	6.67%	6.06%	11/24/1997	6.65%
1/10/2000	6.584	6.58%	6.05%	11/25/1997	6.65%
1/7/2000	6.546	6.55%	6.05%	11/26/1997	6.65%
1/6/2000	6.553	6.55%	6.04%	11/27/1997	6.64%
1/5/2000	6.621	6.62%	6.04%	11/28/1997	6.64%

1/4/2000	6.537	6.54%	6.03%	12/1/1997	6.64%
1/3/2000	6.622	6.62%	6.03%	12/2/1997	6.64%
12/31/1999	6.478	6.48%	6.02%	12/3/1997	6.63%
12/30/1999	6.418	6.42%	6.02%	12/4/1997	6.63%
12/29/1999	6.443	6.44%	6.01%	12/5/1997	6.62%
12/28/1999	6.474	6.47%	6.01%	12/8/1997	6.62%
12/27/1999	6.465	6.47%	6.01%	12/9/1997	6.62%
12/24/1999	6.486	6.49%	6.00%	12/10/1997	6.61%
12/23/1999	6.489	6.49%	6.00%	12/11/1997	6.61%
12/22/1999	6.451	6.45%	5.99%	12/12/1997	6.60%
12/21/1999	6.461	6.46%	5.99%	12/15/1997	6.60%
12/20/1999	6.443	6.44%	5.98%	12/16/1997	6.60%
12/17/1999	6.374	6.37%	5.98%	12/17/1997	6.59%
12/16/1999	6.391	6.39%	5.97%	12/18/1997	6.59%
12/15/1999	6.325	6.33%	5.97%	12/19/1997	6.58%
12/14/1999	6.306	6.31%	5.96%	12/22/1997	6.58%
12/13/1999	6.202	6.20%	5.96%	12/23/1997	6.57%
12/10/1999	6.166	6.17%	5.96%	12/24/1997	6.56%
12/9/1999	6.215	6.22%	5.95%	12/25/1997	6.56%
12/8/1999	6.229	6.23%	5.95%	12/26/1997	6.55%
12/7/1999	6.2	6.20%	5.95%	12/29/1997	6.55%
12/6/1999	6.238	6.24%	5.95%	12/30/1997	6.54%
12/3/1999	6.252	6.25%	5.94%	12/31/1997	6.54%
12/2/1999	6.321	6.32%	5.94%	1/1/1998	6.53%
12/1/1999	6.294	6.29%	5.94%	1/2/1998	6.53%
11/30/1999	6.293	6.29%	5.93%	1/5/1998	6.52%
11/29/1999	6.308	6.31%	5.93%	1/6/1998	6.51%
11/26/1999	6.232	6.23%	5.92%	1/7/1998	6.51%
11/25/1999	6.211	6.21%	5.92%	1/8/1998	6.50%
11/24/1999	6.211	6.21%	5.92%	1/9/1998	6.49%
11/23/1999	6.196	6.20%	5.91%	1/12/1998	6.49%
11/22/1999	6.19	6.19%	5.91%	1/13/1998	6.48%
11/19/1999	6.162	6.16%	5.90%	1/14/1998	6.47%
11/18/1999	6.168	6.17%	5.90%	1/15/1998	6.47%
11/17/1999	6.132	6.13%	5.90%	1/16/1998	6.46%
11/16/1999	6.063	6.06%	5.89%	1/19/1998	6.45%
11/15/1999	6.024	6.02%	5.89%	1/20/1998	6.45%
11/12/1999	6.036	6.04%	5.88%	1/21/1998	6.44%
11/11/1999	6.088	6.09%	5.88%	1/22/1998	6.43%
11/10/1999	6.09	6.09%	5.88%	1/23/1998	6.43%
11/9/1999	6.071	6.07%	5.87%	1/26/1998	6.42%
11/8/1999	6.053	6.05%	5.87%	1/27/1998	6.42%
11/5/1999	6.056	6.06%	5.86%	1/28/1998	6.41%
11/4/1999	6.103	6.10%	5.86%	1/29/1998	6.40%
11/3/1999	6.132	6.13%	5.85%	1/30/1998	6.40%
11/2/1999	6.139	6.14%	5.85%	2/2/1998	6.39%
11/1/1999	6.179	6.18%	5.84%	2/3/1998	6.39%

10/29/1999	6.163	6.16%	5.84%	2/4/1998	6.38%
10/28/1999	6.252	6.25%	5.83%	2/5/1998	6.38%
10/27/1999	6.331	6.33%	5.83%	2/6/1998	6.37%
10/26/1999	6.384	6.38%	5.82%	2/9/1998	6.37%
10/25/1999	6.35	6.35%	5.82%	2/10/1998	6.36%
10/22/1999	6.351	6.35%	5.81%	2/11/1998	6.36%
10/21/1999	6.356	6.36%	5.80%	2/12/1998	6.35%
10/20/1999	6.335	6.34%	5.80%	2/13/1998	6.35%
10/19/1999	6.351	6.35%	5.79%	2/16/1998	6.34%
10/18/1999	6.32	6.32%	5.79%	2/17/1998	6.33%
10/15/1999	6.257	6.26%	5.78%	2/18/1998	6.33%
10/14/1999	6.325	6.33%	5.78%	2/19/1998	6.32%
10/13/1999	6.278	6.28%	5.77%	2/20/1998	6.32%
10/12/1999	6.224	6.22%	5.76%	2/23/1998	6.31%
10/11/1999	6.197	6.20%	5.76%	2/24/1998	6.31%
10/8/1999	6.195	6.20%	5.75%	2/25/1998	6.30%
10/7/1999	6.183	6.18%	5.75%	2/26/1998	6.30%
10/6/1999	6.18	6.18%	5.74%	2/27/1998	6.29%
10/5/1999	6.177	6.18%	5.74%	3/2/1998	6.29%
10/4/1999	6.087	6.09%	5.73%	3/3/1998	6.28%
10/1/1999	6.134	6.13%	5.73%	3/4/1998	6.28%
9/30/1999	6.051	6.05%	5.72%	3/5/1998	6.27%
9/29/1999	6.125	6.13%	5.72%	3/6/1998	6.27%
9/28/1999	6.086	6.09%	5.71%	3/9/1998	6.27%
9/27/1999	6.011	6.01%	5.71%	3/10/1998	6.26%
9/24/1999	5.973	5.97%	5.70%	3/11/1998	6.26%
9/23/1999	5.989	5.99%	5.70%	3/12/1998	6.25%
9/22/1999	6.085	6.09%	5.69%	3/13/1998	6.25%
9/21/1999	6.089	6.09%	5.69%	3/16/1998	6.24%
9/20/1999	6.071	6.07%	5.68%	3/17/1998	6.24%
9/17/1999	6.056	6.06%	5.68%	3/18/1998	6.23%
9/16/1999	6.076	6.08%	5.67%	3/19/1998	6.23%
9/15/1999	6.104	6.10%	5.67%	3/20/1998	6.22%
9/14/1999	6.119	6.12%	5.66%	3/23/1998	6.22%
9/13/1999	6.052	6.05%	5.66%	3/24/1998	6.22%
9/10/1999	6.041	6.04%	5.65%	3/25/1998	6.21%
9/9/1999	6.093	6.09%	5.65%	3/26/1998	6.21%
9/8/1999	6.068	6.07%	5.64%	3/27/1998	6.20%
9/7/1999	6.073	6.07%	5.64%	3/30/1998	6.20%
9/6/1999	6.024	6.02%	5.63%	3/31/1998	6.20%
9/3/1999	6.018	6.02%	5.63%	4/1/1998	6.19%
9/2/1999	6.134	6.13%	5.62%	4/2/1998	6.19%
9/1/1999	6.078	6.08%	5.62%	4/3/1998	6.18%
8/31/1999	6.059	6.06%	5.61%	4/6/1998	6.18%
8/30/1999	6.06	6.06%	5.61%	4/7/1998	6.17%
8/27/1999	5.976	5.98%	5.60%	4/8/1998	6.17%
8/26/1999	5.901	5.90%	5.60%	4/9/1998	6.17%

8/25/1999	5.857	5.86%	5.60%	4/10/1998	6.16%
8/24/1999	5.931	5.93%	5.59%	4/13/1998	6.16%
8/23/1999	5.983	5.98%	5.59%	4/14/1998	6.16%
8/20/1999	5.985	5.99%	5.59%	4/15/1998	6.15%
8/19/1999	6.031	6.03%	5.58%	4/16/1998	6.15%
8/18/1999	5.995	6.00%	5.58%	4/17/1998	6.15%
8/17/1999	6.008	6.01%	5.58%	4/20/1998	6.14%
8/16/1999	6.087	6.09%	5.57%	4/21/1998	6.14%
8/13/1999	6.103	6.10%	5.57%	4/22/1998	6.14%
8/12/1999	6.277	6.28%	5.57%	4/23/1998	6.13%
8/11/1999	6.207	6.21%	5.56%	4/24/1998	6.13%
8/10/1999	6.242	6.24%	5.56%	4/27/1998	6.13%
8/9/1999	6.233	6.23%	5.55%	4/28/1998	6.13%
8/6/1999	6.176	6.18%	5.55%	4/29/1998	6.13%
8/5/1999	6.039	6.04%	5.54%	4/30/1998	6.12%
8/4/1999	6.107	6.11%	5.54%	5/1/1998	6.12%
8/3/1999	6.164	6.16%	5.53%	5/4/1998	6.12%
8/2/1999	6.121	6.12%	5.53%	5/5/1998	6.12%
7/30/1999	6.103	6.10%	5.52%	5/6/1998	6.11%
7/29/1999	6.071	6.07%	5.52%	5/7/1998	6.11%
7/28/1999	6.009	6.01%	5.51%	5/8/1998	6.11%
7/27/1999	6.01	6.01%	5.51%	5/11/1998	6.11%
7/26/1999	6.028	6.03%	5.50%	5/12/1998	6.11%
7/23/1999	6.025	6.03%	5.50%	5/13/1998	6.10%
7/22/1999	5.971	5.97%	5.49%	5/14/1998	6.10%
7/21/1999	5.904	5.90%	5.49%	5/15/1998	6.10%
7/20/1999	5.886	5.89%	5.48%	5/18/1998	6.09%
7/19/1999	5.901	5.90%	5.48%	5/19/1998	6.09%
7/16/1999	5.884	5.88%	5.47%	5/20/1998	6.09%
7/15/1999	5.918	5.92%	5.47%	5/21/1998	6.08%
7/14/1999	5.914	5.91%	5.47%	5/22/1998	6.08%
7/13/1999	5.91	5.91%	5.46%	5/25/1998	6.08%
7/12/1999	5.907	5.91%	5.45%	5/26/1998	6.07%
7/9/1999	5.999	6.00%	5.45%	5/27/1998	6.07%
7/8/1999	5.991	5.99%	5.44%	5/28/1998	6.07%
7/7/1999	6.048	6.05%	5.44%	5/29/1998	6.06%
7/6/1999	6.037	6.04%	5.43%	6/1/1998	6.06%
7/5/1999	5.996	6.00%	5.43%	6/2/1998	6.05%
7/2/1999	5.998	6.00%	5.42%	6/3/1998	6.05%
7/1/1999	6.011	6.01%	5.42%	6/4/1998	6.04%
6/30/1999	5.963	5.96%	5.41%	6/5/1998	6.04%
6/29/1999	6.068	6.07%	5.41%	6/8/1998	6.04%
6/28/1999	6.094	6.09%	5.41%	6/9/1998	6.03%
6/25/1999	6.15	6.15%	5.40%	6/10/1998	6.03%
6/24/1999	6.161	6.16%	5.40%	6/11/1998	6.02%
6/23/1999	6.147	6.15%	5.39%	6/12/1998	6.02%
6/22/1999	6.057	6.06%	5.39%	6/15/1998	6.01%

6/21/1999	6.019	6.02%	5.38%	6/16/1998	6.01%
6/18/1999	5.972	5.97%	5.38%	6/17/1998	6.00%
6/17/1999	5.963	5.96%	5.37%	6/18/1998	6.00%
6/16/1999	6.066	6.07%	5.37%	6/19/1998	5.99%
6/15/1999	6.111	6.11%	5.37%	6/22/1998	5.99%
6/14/1999	6.1	6.10%	5.36%	6/23/1998	5.99%
6/11/1999	6.159	6.16%	5.36%	6/24/1998	5.98%
6/10/1999	6.063	6.06%	5.35%	6/25/1998	5.98%
6/9/1999	6.026	6.03%	5.35%	6/26/1998	5.97%
6/8/1999	5.994	5.99%	5.35%	6/29/1998	5.97%
6/7/1999	5.966	5.97%	5.34%	6/30/1998	5.97%
6/4/1999	5.963	5.96%	5.34%	7/1/1998	5.96%
6/3/1999	5.963	5.96%	5.34%	7/2/1998	5.96%
6/2/1999	5.934	5.93%	5.33%	7/3/1998	5.96%
6/1/1999	5.924	5.92%	5.33%	7/6/1998	5.95%
5/31/1999	5.828	5.83%	5.33%	7/7/1998	5.95%
5/28/1999	5.828	5.83%	5.33%	7/8/1998	5.94%
5/27/1999	5.852	5.85%	5.33%	7/9/1998	5.94%
5/26/1999	5.804	5.80%	5.32%	7/10/1998	5.94%
5/25/1999	5.748	5.75%	5.32%	7/13/1998	5.93%
5/24/1999	5.757	5.76%	5.32%	7/14/1998	5.93%
5/21/1999	5.751	5.75%	5.32%	7/15/1998	5.93%
5/20/1999	5.827	5.83%	5.32%	7/16/1998	5.93%
5/19/1999	5.803	5.80%	5.32%	7/17/1998	5.92%
5/18/1999	5.89	5.89%	5.32%	7/20/1998	5.92%
5/17/1999	5.892	5.89%	5.32%	7/21/1998	5.91%
5/14/1999	5.922	5.92%	5.32%	7/22/1998	5.91%
5/13/1999	5.75	5.75%	5.31%	7/23/1998	5.91%
5/12/1999	5.828	5.83%	5.31%	7/24/1998	5.90%
5/11/1999	5.835	5.84%	5.31%	7/27/1998	5.90%
5/10/1999	5.79	5.79%	5.31%	7/28/1998	5.90%
5/7/1999	5.813	5.81%	5.31%	7/29/1998	5.89%
5/6/1999	5.791	5.79%	5.31%	7/30/1998	5.89%
5/5/1999	5.706	5.71%	5.31%	7/31/1998	5.89%
5/4/1999	5.713	5.71%	5.31%	8/3/1998	5.89%
5/3/1999	5.655	5.66%	5.31%	8/4/1998	5.88%
4/30/1999	5.662	5.66%	5.31%	8/5/1998	5.88%
4/29/1999	5.53	5.53%	5.31%	8/6/1998	5.88%
4/28/1999	5.583	5.58%	5.31%	8/7/1998	5.87%
4/27/1999	5.538	5.54%	5.31%	8/10/1998	5.87%
4/26/1999	5.575	5.58%	5.31%	8/11/1998	5.87%
4/23/1999	5.597	5.60%	5.31%	8/12/1998	5.87%
4/22/1999	5.603	5.60%	5.31%	8/13/1998	5.86%
4/21/1999	5.524	5.52%	5.31%	8/14/1998	5.86%
4/20/1999	5.507	5.51%	5.32%	8/17/1998	5.86%
4/19/1999	5.519	5.52%	5.32%	8/18/1998	5.85%
4/16/1999	5.573	5.57%	5.32%	8/19/1998	5.85%

4/15/1999	5.526	5.53%	5.32%	8/20/1998	5.85%
4/14/1999	5.507	5.51%	5.32%	8/21/1998	5.84%
4/13/1999	5.49	5.49%	5.32%	8/24/1998	5.84%
4/12/1999	5.452	5.45%	5.32%	8/25/1998	5.84%
4/9/1999	5.46	5.46%	5.32%	8/26/1998	5.84%
4/8/1999	5.443	5.44%	5.32%	8/27/1998	5.83%
4/7/1999	5.503	5.50%	5.32%	8/28/1998	5.83%
4/6/1999	5.519	5.52%	5.32%	8/31/1998	5.82%
4/5/1999	5.588	5.59%	5.32%	9/1/1998	5.82%
4/2/1999	5.596	5.60%	5.32%	9/2/1998	5.82%
4/1/1999	5.671	5.67%	5.32%	9/3/1998	5.81%
3/31/1999	5.625	5.63%	5.32%	9/4/1998	5.81%
3/30/1999	5.58	5.58%	5.32%	9/7/1998	5.81%
3/29/1999	5.64	5.64%	5.32%	9/8/1998	5.80%
3/26/1999	5.589	5.59%	5.32%	9/9/1998	5.80%
3/25/1999	5.585	5.59%	5.32%	9/10/1998	5.79%
3/24/1999	5.531	5.53%	5.32%	9/11/1998	5.79%
3/23/1999	5.541	5.54%	5.33%	9/14/1998	5.79%
3/22/1999	5.568	5.57%	5.33%	9/15/1998	5.78%
3/19/1999	5.56	5.56%	5.33%	9/16/1998	5.78%
3/18/1999	5.488	5.49%	5.33%	9/17/1998	5.77%
3/17/1999	5.507	5.51%	5.33%	9/18/1998	5.77%
3/16/1999	5.476	5.48%	5.33%	9/21/1998	5.76%
3/15/1999	5.521	5.52%	5.33%	9/22/1998	5.76%
3/12/1999	5.526	5.53%	5.33%	9/23/1998	5.76%
3/11/1999	5.563	5.56%	5.33%	9/24/1998	5.75%
3/10/1999	5.555	5.56%	5.33%	9/25/1998	5.75%
3/9/1999	5.531	5.53%	5.33%	9/28/1998	5.75%
3/8/1999	5.588	5.59%	5.34%	9/29/1998	5.74%
3/5/1999	5.596	5.60%	5.34%	9/30/1998	5.74%
3/4/1999	5.701	5.70%	5.34%	10/1/1998	5.73%
3/3/1999	5.696	5.70%	5.34%	10/2/1998	5.73%
3/2/1999	5.614	5.61%	5.34%	10/5/1998	5.72%
3/1/1999	5.67	5.67%	5.34%	10/6/1998	5.71%
2/26/1999	5.576	5.58%	5.34%	10/7/1998	5.71%
2/25/1999	5.653	5.65%	5.34%	10/8/1998	5.70%
2/24/1999	5.508	5.51%	5.34%	10/9/1998	5.70%
2/23/1999	5.43	5.43%	5.35%	10/12/1998	5.70%
2/22/1999	5.355	5.36%	5.35%	10/13/1998	5.69%
2/19/1999	5.387	5.39%	5.35%	10/14/1998	5.69%
2/18/1999	5.378	5.38%	5.36%	10/15/1998	5.69%
2/17/1999	5.308	5.31%	5.36%	10/16/1998	5.68%
2/16/1999	5.341	5.34%	5.36%	10/19/1998	5.68%
2/15/1999	5.427	5.43%	5.36%	10/20/1998	5.68%
2/12/1999	5.422	5.42%	5.37%	10/21/1998	5.67%
2/11/1999	5.366	5.37%	5.37%	10/22/1998	5.67%
2/10/1999	5.366	5.37%	5.37%	10/23/1998	5.67%

2/9/1999	5.302	5.30%	5.38%	10/26/1998	5.66%
2/8/1999	5.341	5.34%	5.38%	10/27/1998	5.66%
2/5/1999	5.349	5.35%	5.38%	10/28/1998	5.66%
2/4/1999	5.288	5.29%	5.39%	10/29/1998	5.65%
2/3/1999	5.254	5.25%	5.39%	10/30/1998	5.65%
2/2/1999	5.239	5.24%	5.39%	11/2/1998	5.64%
2/1/1999	5.183	5.18%	5.40%	11/3/1998	5.64%
1/29/1999	5.086	5.09%	5.40%	11/4/1998	5.64%
1/28/1999	5.107	5.11%	5.41%	11/5/1998	5.64%
1/27/1999	5.127	5.13%	5.41%	11/6/1998	5.63%
1/26/1999	5.129	5.13%	5.41%	11/9/1998	5.63%
1/25/1999	5.116	5.12%	5.42%	11/10/1998	5.63%
1/22/1999	5.082	5.08%	5.42%	11/11/1998	5.62%
1/21/1999	5.131	5.13%	5.43%	11/12/1998	5.62%
1/20/1999	5.168	5.17%	5.43%	11/13/1998	5.62%
1/19/1999	5.149	5.15%	5.43%	11/16/1998	5.61%
1/18/1999	5.115	5.12%	5.44%	11/17/1998	5.61%
1/15/1999	5.107	5.11%	5.44%	11/18/1998	5.61%
1/14/1999	5.057	5.06%	5.45%	11/19/1998	5.61%
1/13/1999	5.132	5.13%	5.45%	11/20/1998	5.60%
1/12/1999	5.22	5.22%	5.45%	11/23/1998	5.60%
1/11/1999	5.306	5.31%	5.46%	11/24/1998	5.60%
1/8/1999	5.273	5.27%	5.46%	11/25/1998	5.59%
1/7/1999	5.224	5.22%	5.46%	11/26/1998	5.59%
1/6/1999	5.163	5.16%	5.46%	11/27/1998	5.59%
1/5/1999	5.208	5.21%	5.47%	11/30/1998	5.58%
1/4/1999	5.151	5.15%	5.47%	12/1/1998	5.58%
1/1/1999	5.095	5.10%	5.48%	12/2/1998	5.57%
12/31/1998	5.095	5.10%	5.48%	12/3/1998	5.57%
12/30/1998	5.087	5.09%	5.48%	12/4/1998	5.56%
12/29/1998	5.1	5.10%	5.49%	12/7/1998	5.56%
12/28/1998	5.152	5.15%	5.49%	12/8/1998	5.55%
12/25/1998	5.216	5.22%	5.50%	12/9/1998	5.55%
12/24/1998	5.213	5.21%	5.50%	12/10/1998	5.54%
12/23/1998	5.177	5.18%	5.50%	12/11/1998	5.54%
12/22/1998	5.138	5.14%	5.51%	12/14/1998	5.53%
12/21/1998	5.06	5.06%	5.51%	12/15/1998	5.53%
12/18/1998	4.998	5.00%	5.51%	12/16/1998	5.52%
12/17/1998	5.012	5.01%	5.52%	12/17/1998	5.52%
12/16/1998	4.994	4.99%	5.52%	12/18/1998	5.51%
12/15/1998	5.025	5.03%	5.53%	12/21/1998	5.51%
12/14/1998	4.99	4.99%	5.53%	12/22/1998	5.51%
12/11/1998	5.024	5.02%	5.54%	12/23/1998	5.50%
12/10/1998	4.955	4.96%	5.54%	12/24/1998	5.50%
12/9/1998	4.982	4.98%	5.55%	12/25/1998	5.50%
12/8/1998	4.993	4.99%	5.55%	12/28/1998	5.49%
12/7/1998	5.034	5.03%	5.56%	12/29/1998	5.49%

12/4/1998	5.04	5.04%	5.56%	12/30/1998	5.48%
12/3/1998	5.003	5.00%	5.57%	12/31/1998	5.48%
12/2/1998	5.023	5.02%	5.57%	1/1/1999	5.48%
12/1/1998	5.036	5.04%	5.58%	1/4/1999	5.47%
11/30/1998	5.063	5.06%	5.58%	1/5/1999	5.47%
11/27/1998	5.159	5.16%	5.59%	1/6/1999	5.46%
11/26/1998	5.186	5.19%	5.59%	1/7/1999	5.46%
11/25/1998	5.187	5.19%	5.59%	1/8/1999	5.46%
11/24/1998	5.217	5.22%	5.60%	1/11/1999	5.46%
11/23/1998	5.252	5.25%	5.60%	1/12/1999	5.45%
11/20/1998	5.218	5.22%	5.60%	1/13/1999	5.45%
11/19/1998	5.243	5.24%	5.61%	1/14/1999	5.45%
11/18/1998	5.249	5.25%	5.61%	1/15/1999	5.44%
11/17/1998	5.294	5.29%	5.61%	1/18/1999	5.44%
11/16/1998	5.288	5.29%	5.61%	1/19/1999	5.43%
11/13/1998	5.25	5.25%	5.62%	1/20/1999	5.43%
11/12/1998	5.249	5.25%	5.62%	1/21/1999	5.43%
11/11/1998	5.288	5.29%	5.62%	1/22/1999	5.42%
11/10/1998	5.289	5.29%	5.63%	1/25/1999	5.42%
11/9/1998	5.289	5.29%	5.63%	1/26/1999	5.41%
11/6/1998	5.387	5.39%	5.63%	1/27/1999	5.41%
11/5/1998	5.355	5.36%	5.64%	1/28/1999	5.41%
11/4/1998	5.325	5.33%	5.64%	1/29/1999	5.40%
11/3/1998	5.215	5.22%	5.64%	2/1/1999	5.40%
11/2/1998	5.244	5.24%	5.64%	2/2/1999	5.39%
10/30/1998	5.157	5.16%	5.65%	2/3/1999	5.39%
10/29/1998	5.078	5.08%	5.65%	2/4/1999	5.39%
10/28/1998	5.12	5.12%	5.66%	2/5/1999	5.38%
10/27/1998	5.089	5.09%	5.66%	2/8/1999	5.38%
10/26/1998	5.107	5.11%	5.66%	2/9/1999	5.38%
10/23/1998	5.178	5.18%	5.67%	2/10/1999	5.37%
10/22/1998	5.137	5.14%	5.67%	2/11/1999	5.37%
10/21/1998	5.071	5.07%	5.67%	2/12/1999	5.37%
10/20/1998	5.069	5.07%	5.68%	2/15/1999	5.36%
10/19/1998	4.983	4.98%	5.68%	2/16/1999	5.36%
10/16/1998	4.978	4.98%	5.68%	2/17/1999	5.36%
10/15/1998	4.967	4.97%	5.69%	2/18/1999	5.36%
10/14/1998	5.031	5.03%	5.69%	2/19/1999	5.35%
10/13/1998	5.089	5.09%	5.69%	2/22/1999	5.35%
10/12/1998	5.117	5.12%	5.70%	2/23/1999	5.35%
10/9/1998	5.115	5.12%	5.70%	2/24/1999	5.34%
10/8/1998	4.999	5.00%	5.70%	2/25/1999	5.34%
10/7/1998	4.86	4.86%	5.71%	2/26/1999	5.34%
10/6/1998	4.735	4.74%	5.71%	3/1/1999	5.34%
10/5/1998	4.716	4.72%	5.72%	3/2/1999	5.34%
10/2/1998	4.84	4.84%	5.73%	3/3/1999	5.34%
10/1/1998	4.882	4.88%	5.73%	3/4/1999	5.34%

9/30/1998	4.978	4.98%	5.74%	3/5/1999	5.34%
9/29/1998	5.094	5.09%	5.74%	3/8/1999	5.34%
9/28/1998	5.141	5.14%	5.75%	3/9/1999	5.33%
9/25/1998	5.109	5.11%	5.75%	3/10/1999	5.33%
9/24/1998	5.164	5.16%	5.75%	3/11/1999	5.33%
9/23/1998	5.168	5.17%	5.76%	3/12/1999	5.33%
9/22/1998	5.152	5.15%	5.76%	3/15/1999	5.33%
9/21/1998	5.125	5.13%	5.76%	3/16/1999	5.33%
9/18/1998	5.147	5.15%	5.77%	3/17/1999	5.33%
9/17/1998	5.179	5.18%	5.77%	3/18/1999	5.33%
9/16/1998	5.221	5.22%	5.78%	3/19/1999	5.33%
9/15/1998	5.26	5.26%	5.78%	3/22/1999	5.33%
9/14/1998	5.23	5.23%	5.79%	3/23/1999	5.33%
9/11/1998	5.229	5.23%	5.79%	3/24/1999	5.32%
9/10/1998	5.204	5.20%	5.79%	3/25/1999	5.32%
9/9/1998	5.262	5.26%	5.80%	3/26/1999	5.32%
9/8/1998	5.363	5.36%	5.80%	3/29/1999	5.32%
9/7/1998	5.284	5.28%	5.81%	3/30/1999	5.32%
9/4/1998	5.288	5.29%	5.81%	3/31/1999	5.32%
9/3/1998	5.303	5.30%	5.81%	4/1/1999	5.32%
9/2/1998	5.333	5.33%	5.82%	4/2/1999	5.32%
9/1/1998	5.341	5.34%	5.82%	4/5/1999	5.32%
8/31/1998	5.267	5.27%	5.82%	4/6/1999	5.32%
8/28/1998	5.338	5.34%	5.83%	4/7/1999	5.32%
8/27/1998	5.344	5.34%	5.83%	4/8/1999	5.32%
8/26/1998	5.417	5.42%	5.84%	4/9/1999	5.32%
8/25/1998	5.428	5.43%	5.84%	4/12/1999	5.32%
8/24/1998	5.471	5.47%	5.84%	4/13/1999	5.32%
8/21/1998	5.433	5.43%	5.84%	4/14/1999	5.32%
8/20/1998	5.513	5.51%	5.85%	4/15/1999	5.32%
8/19/1998	5.556	5.56%	5.85%	4/16/1999	5.32%
8/18/1998	5.556	5.56%	5.85%	4/19/1999	5.32%
8/17/1998	5.546	5.55%	5.86%	4/20/1999	5.32%
8/14/1998	5.54	5.54%	5.86%	4/21/1999	5.31%
8/13/1998	5.65	5.65%	5.86%	4/22/1999	5.31%
8/12/1998	5.609	5.61%	5.87%	4/23/1999	5.31%
8/11/1998	5.602	5.60%	5.87%	4/26/1999	5.31%
8/10/1998	5.624	5.62%	5.87%	4/27/1999	5.31%
8/7/1998	5.631	5.63%	5.87%	4/28/1999	5.31%
8/6/1998	5.671	5.67%	5.88%	4/29/1999	5.31%
8/5/1998	5.671	5.67%	5.88%	4/30/1999	5.31%
8/4/1998	5.631	5.63%	5.88%	5/3/1999	5.31%
8/3/1998	5.659	5.66%	5.89%	5/4/1999	5.31%
7/31/1998	5.713	5.71%	5.89%	5/5/1999	5.31%
7/30/1998	5.722	5.72%	5.89%	5/6/1999	5.31%
7/29/1998	5.769	5.77%	5.89%	5/7/1999	5.31%
7/28/1998	5.74	5.74%	5.90%	5/10/1999	5.31%

7/27/1998	5.708	5.71%	5.90%	5/11/1999	5.31%
7/24/1998	5.686	5.69%	5.90%	5/12/1999	5.31%
7/23/1998	5.657	5.66%	5.91%	5/13/1999	5.31%
7/22/1998	5.681	5.68%	5.91%	5/14/1999	5.32%
7/21/1998	5.663	5.66%	5.91%	5/17/1999	5.32%
7/20/1998	5.713	5.71%	5.92%	5/18/1999	5.32%
7/17/1998	5.746	5.75%	5.92%	5/19/1999	5.32%
7/16/1998	5.727	5.73%	5.93%	5/20/1999	5.32%
7/15/1998	5.705	5.71%	5.93%	5/21/1999	5.32%
7/14/1998	5.717	5.72%	5.93%	5/24/1999	5.32%
7/13/1998	5.693	5.69%	5.93%	5/25/1999	5.32%
7/10/1998	5.625	5.63%	5.94%	5/26/1999	5.32%
7/9/1998	5.605	5.61%	5.94%	5/27/1999	5.33%
7/8/1998	5.626	5.63%	5.94%	5/28/1999	5.33%
7/7/1998	5.603	5.60%	5.95%	5/31/1999	5.33%
7/6/1998	5.572	5.57%	5.95%	6/1/1999	5.33%
7/3/1998	5.599	5.60%	5.96%	6/2/1999	5.33%
7/2/1998	5.6	5.60%	5.96%	6/3/1999	5.34%
7/1/1998	5.629	5.63%	5.96%	6/4/1999	5.34%
6/30/1998	5.627	5.63%	5.97%	6/7/1999	5.34%
6/29/1998	5.643	5.64%	5.97%	6/8/1999	5.35%
6/26/1998	5.632	5.63%	5.97%	6/9/1999	5.35%
6/25/1998	5.655	5.66%	5.98%	6/10/1999	5.35%
6/24/1998	5.658	5.66%	5.98%	6/11/1999	5.36%
6/23/1998	5.643	5.64%	5.99%	6/14/1999	5.36%
6/22/1998	5.669	5.67%	5.99%	6/15/1999	5.37%
6/19/1998	5.669	5.67%	5.99%	6/16/1999	5.37%
6/18/1998	5.7	5.70%	6.00%	6/17/1999	5.37%
6/17/1998	5.747	5.75%	6.00%	6/18/1999	5.38%
6/16/1998	5.649	5.65%	6.01%	6/21/1999	5.38%
6/15/1998	5.574	5.57%	6.01%	6/22/1999	5.39%
6/12/1998	5.662	5.66%	6.02%	6/23/1999	5.39%
6/11/1998	5.654	5.65%	6.02%	6/24/1999	5.40%
6/10/1998	5.702	5.70%	6.03%	6/25/1999	5.40%
6/9/1998	5.788	5.79%	6.03%	6/28/1999	5.41%
6/8/1998	5.779	5.78%	6.04%	6/29/1999	5.41%
6/5/1998	5.787	5.79%	6.04%	6/30/1999	5.41%
6/4/1998	5.817	5.82%	6.04%	7/1/1999	5.42%
6/3/1998	5.782	5.78%	6.05%	7/2/1999	5.42%
6/2/1998	5.79	5.79%	6.05%	7/5/1999	5.43%
6/1/1998	5.777	5.78%	6.06%	7/6/1999	5.43%
5/29/1998	5.802	5.80%	6.06%	7/7/1999	5.44%
5/28/1998	5.825	5.83%	6.07%	7/8/1999	5.44%
5/27/1998	5.846	5.85%	6.07%	7/9/1999	5.45%
5/26/1998	5.836	5.84%	6.07%	7/12/1999	5.45%
5/25/1998	5.9	5.90%	6.08%	7/13/1999	5.46%
5/22/1998	5.9	5.90%	6.08%	7/14/1999	5.47%

5/21/1998	5.923	5.92%	6.08%	7/15/1999	5.47%
5/20/1998	5.895	5.90%	6.09%	7/16/1999	5.47%
5/19/1998	5.934	5.93%	6.09%	7/19/1999	5.48%
5/18/1998	5.923	5.92%	6.09%	7/20/1999	5.48%
5/15/1998	5.972	5.97%	6.10%	7/21/1999	5.49%
5/14/1998	5.984	5.98%	6.10%	7/22/1999	5.49%
5/13/1998	5.939	5.94%	6.10%	7/23/1999	5.50%
5/12/1998	5.972	5.97%	6.11%	7/26/1999	5.50%
5/11/1998	6.029	6.03%	6.11%	7/27/1999	5.51%
5/8/1998	5.977	5.98%	6.11%	7/28/1999	5.51%
5/7/1998	5.953	5.95%	6.11%	7/29/1999	5.52%
5/6/1998	5.94	5.94%	6.11%	7/30/1999	5.52%
5/5/1998	5.987	5.99%	6.12%	8/2/1999	5.53%
5/4/1998	5.937	5.94%	6.12%	8/3/1999	5.53%
5/1/1998	5.933	5.93%	6.12%	8/4/1999	5.54%
4/30/1998	5.949	5.95%	6.12%	8/5/1999	5.54%
4/29/1998	6.075	6.08%	6.13%	8/6/1999	5.55%
4/28/1998	6.069	6.07%	6.13%	8/9/1999	5.55%
4/27/1998	6.053	6.05%	6.13%	8/10/1999	5.56%
4/24/1998	5.945	5.95%	6.13%	8/11/1999	5.56%
4/23/1998	5.981	5.98%	6.13%	8/12/1999	5.57%
4/22/1998	5.956	5.96%	6.14%	8/13/1999	5.57%
4/21/1998	5.948	5.95%	6.14%	8/16/1999	5.57%
4/20/1998	5.925	5.93%	6.14%	8/17/1999	5.58%
4/17/1998	5.876	5.88%	6.15%	8/18/1999	5.58%
4/16/1998	5.871	5.87%	6.15%	8/19/1999	5.58%
4/15/1998	5.883	5.88%	6.15%	8/20/1999	5.59%
4/14/1998	5.899	5.90%	6.16%	8/23/1999	5.59%
4/13/1998	5.926	5.93%	6.16%	8/24/1999	5.59%
4/10/1998	5.881	5.88%	6.16%	8/25/1999	5.60%
4/9/1998	5.879	5.88%	6.17%	8/26/1999	5.60%
4/8/1998	5.896	5.90%	6.17%	8/27/1999	5.60%
4/7/1998	5.843	5.84%	6.17%	8/30/1999	5.61%
4/6/1998	5.824	5.82%	6.18%	8/31/1999	5.61%
4/3/1998	5.794	5.79%	6.18%	9/1/1999	5.62%
4/2/1998	5.841	5.84%	6.19%	9/2/1999	5.62%
4/1/1998	5.881	5.88%	6.19%	9/3/1999	5.63%
3/31/1998	5.933	5.93%	6.20%	9/6/1999	5.63%
3/30/1998	5.979	5.98%	6.20%	9/7/1999	5.64%
3/27/1998	5.958	5.96%	6.20%	9/8/1999	5.64%
3/26/1998	5.975	5.98%	6.21%	9/9/1999	5.65%
3/25/1998	5.942	5.94%	6.21%	9/10/1999	5.65%
3/24/1998	5.88	5.88%	6.22%	9/13/1999	5.66%
3/23/1998	5.883	5.88%	6.22%	9/14/1999	5.66%
3/20/1998	5.885	5.89%	6.22%	9/15/1999	5.67%
3/19/1998	5.9	5.90%	6.23%	9/16/1999	5.67%
3/18/1998	5.907	5.91%	6.23%	9/17/1999	5.68%

3/17/1998	5.89	5.89%	6.24%	9/20/1999	5.68%
3/16/1998	5.862	5.86%	6.24%	9/21/1999	5.69%
3/13/1998	5.893	5.89%	6.25%	9/22/1999	5.69%
3/12/1998	5.866	5.87%	6.25%	9/23/1999	5.70%
3/11/1998	5.939	5.94%	6.26%	9/24/1999	5.70%
3/10/1998	5.96	5.96%	6.26%	9/27/1999	5.71%
3/9/1998	5.962	5.96%	6.27%	9/28/1999	5.71%
3/6/1998	6.019	6.02%	6.27%	9/29/1999	5.72%
3/5/1998	6.063	6.06%	6.27%	9/30/1999	5.72%
3/4/1998	6.023	6.02%	6.28%	10/1/1999	5.73%
3/3/1998	6.073	6.07%	6.28%	10/4/1999	5.73%
3/2/1998	6.011	6.01%	6.29%	10/5/1999	5.74%
2/27/1998	5.923	5.92%	6.29%	10/6/1999	5.74%
2/26/1998	5.947	5.95%	6.30%	10/7/1999	5.75%
2/25/1998	5.921	5.92%	6.30%	10/8/1999	5.75%
2/24/1998	5.961	5.96%	6.31%	10/11/1999	5.76%
2/23/1998	5.9	5.90%	6.31%	10/12/1999	5.76%
2/20/1998	5.871	5.87%	6.32%	10/13/1999	5.77%
2/19/1998	5.851	5.85%	6.32%	10/14/1999	5.78%
2/18/1998	5.837	5.84%	6.33%	10/15/1999	5.78%
2/17/1998	5.796	5.80%	6.33%	10/18/1999	5.79%
2/16/1998	5.848	5.85%	6.34%	10/19/1999	5.79%
2/13/1998	5.849	5.85%	6.35%	10/20/1999	5.80%
2/12/1998	5.865	5.87%	6.35%	10/21/1999	5.80%
2/11/1998	5.846	5.85%	6.36%	10/22/1999	5.81%
2/10/1998	5.922	5.92%	6.36%	10/25/1999	5.82%
2/9/1998	5.943	5.94%	6.37%	10/26/1999	5.82%
2/6/1998	5.92	5.92%	6.37%	10/27/1999	5.83%
2/5/1998	5.933	5.93%	6.38%	10/28/1999	5.83%
2/4/1998	5.862	5.86%	6.38%	10/29/1999	5.84%
2/3/1998	5.863	5.86%	6.39%	11/1/1999	5.84%
2/2/1998	5.878	5.88%	6.39%	11/2/1999	5.85%
1/30/1998	5.8	5.80%	6.40%	11/3/1999	5.85%
1/29/1998	5.841	5.84%	6.40%	11/4/1999	5.86%
1/28/1998	5.942	5.94%	6.41%	11/5/1999	5.86%
1/27/1998	5.94	5.94%	6.42%	11/8/1999	5.87%
1/26/1998	5.897	5.90%	6.42%	11/9/1999	5.87%
1/23/1998	5.97	5.97%	6.43%	11/10/1999	5.88%
1/22/1998	5.866	5.87%	6.43%	11/11/1999	5.88%
1/21/1998	5.811	5.81%	6.44%	11/12/1999	5.88%
1/20/1998	5.845	5.85%	6.45%	11/15/1999	5.89%
1/19/1998	5.809	5.81%	6.45%	11/16/1999	5.89%
1/16/1998	5.809	5.81%	6.46%	11/17/1999	5.90%
1/15/1998	5.739	5.74%	6.47%	11/18/1999	5.90%
1/14/1998	5.733	5.73%	6.47%	11/19/1999	5.90%
1/13/1998	5.738	5.74%	6.48%	11/22/1999	5.91%
1/12/1998	5.689	5.69%	6.49%	11/23/1999	5.91%

1/9/1998	5.728	5.73%	6.49%	11/24/1999	5.92%
1/8/1998	5.75	5.75%	6.50%	11/25/1999	5.92%
1/7/1998	5.787	5.79%	6.51%	11/26/1999	5.92%
1/6/1998	5.718	5.72%	6.51%	11/29/1999	5.93%
1/5/1998	5.735	5.74%	6.52%	11/30/1999	5.93%
1/2/1998	5.838	5.84%	6.53%	12/1/1999	5.94%
1/1/1998	5.925	5.93%	6.53%	12/2/1999	5.94%
12/31/1997	5.923	5.92%	6.54%	12/3/1999	5.94%
12/30/1997	5.97	5.97%	6.54%	12/6/1999	5.95%
12/29/1997	5.925	5.93%	6.55%	12/7/1999	5.95%
12/26/1997	5.9	5.90%	6.55%	12/8/1999	5.95%
12/25/1997	5.911	5.91%	6.56%	12/9/1999	5.95%
12/24/1997	5.913	5.91%	6.56%	12/10/1999	5.96%
12/23/1997	5.873	5.87%	6.57%	12/13/1999	5.96%
12/22/1997	5.886	5.89%	6.58%	12/14/1999	5.96%
12/19/1997	5.922	5.92%	6.58%	12/15/1999	5.97%
12/18/1997	5.934	5.93%	6.59%	12/16/1999	5.97%
12/17/1997	5.997	6.00%	6.59%	12/17/1999	5.98%
12/16/1997	5.963	5.96%	6.60%	12/20/1999	5.98%
12/15/1997	5.973	5.97%	6.60%	12/21/1999	5.99%
12/12/1997	5.925	5.93%	6.60%	12/22/1999	5.99%
12/11/1997	5.994	5.99%	6.61%	12/23/1999	6.00%
12/10/1997	6.07	6.07%	6.61%	12/24/1999	6.00%
12/9/1997	6.117	6.12%	6.62%	12/27/1999	6.01%
12/8/1997	6.143	6.14%	6.62%	12/28/1999	6.01%
12/5/1997	6.084	6.08%	6.62%	12/29/1999	6.01%
12/4/1997	6.049	6.05%	6.63%	12/30/1999	6.02%
12/3/1997	6.015	6.02%	6.63%	12/31/1999	6.02%
12/2/1997	6.036	6.04%	6.64%	1/3/2000	6.03%
12/1/1997	6.038	6.04%	6.64%	1/4/2000	6.03%
11/28/1997	6.054	6.05%	6.64%	1/5/2000	6.04%
11/27/1997	6.05	6.05%	6.64%	1/6/2000	6.04%
11/26/1997	6.047	6.05%	6.65%	1/7/2000	6.05%
11/25/1997	6.06	6.06%	6.65%	1/10/2000	6.05%
11/24/1997	6.067	6.07%	6.65%	1/11/2000	6.06%
11/21/1997	6.033	6.03%	6.65%	1/12/2000	6.06%
11/20/1997	6.062	6.06%	6.66%	1/13/2000	6.07%
11/19/1997	6.039	6.04%	6.66%	1/14/2000	6.08%
11/18/1997	6.073	6.07%	6.66%	1/17/2000	6.08%
11/17/1997	6.067	6.07%	6.67%	1/18/2000	6.09%
11/14/1997	6.113	6.11%	6.67%	1/19/2000	6.09%
11/13/1997	6.098	6.10%	6.67%	1/20/2000	6.10%
11/12/1997	6.102	6.10%	6.68%	1/21/2000	6.11%
11/11/1997	6.143	6.14%	6.68%	1/24/2000	6.11%
11/10/1997	6.143	6.14%	6.68%	1/25/2000	6.12%
11/7/1997	6.155	6.16%	6.69%	1/26/2000	6.12%
11/6/1997	6.183	6.18%	6.69%	1/27/2000	6.13%

11/5/1997	6.218	6.22%	6.69%	1/28/2000	6.13%
11/4/1997	6.252	6.25%	6.70%	1/31/2000	6.14%
11/3/1997	6.209	6.21%	6.70%	2/1/2000	6.14%
10/31/1997	6.153	6.15%	6.70%	2/2/2000	6.14%
10/30/1997	6.14	6.14%	6.71%	2/3/2000	6.15%
10/29/1997	6.203	6.20%	6.71%	2/4/2000	6.15%
10/28/1997	6.289	6.29%	6.71%	2/7/2000	6.15%
10/27/1997	6.133	6.13%	6.72%	2/8/2000	6.16%
10/24/1997	6.273	6.27%	6.72%	2/9/2000	6.16%
10/23/1997	6.309	6.31%	6.72%	2/10/2000	6.16%
10/22/1997	6.419	6.42%	6.72%	2/11/2000	6.16%
10/21/1997	6.41	6.41%	6.73%	2/14/2000	6.17%
10/20/1997	6.423	6.42%	6.73%	2/15/2000	6.17%
10/17/1997	6.439	6.44%	6.73%	2/16/2000	6.17%
10/16/1997	6.392	6.39%	6.73%	2/17/2000	6.17%
10/15/1997	6.397	6.40%	6.73%	2/18/2000	6.17%
10/14/1997	6.356	6.36%	6.74%	2/21/2000	6.18%
10/13/1997	6.432	6.43%	6.74%	2/22/2000	6.18%
10/10/1997	6.43	6.43%	6.74%	2/23/2000	6.18%
10/9/1997	6.354	6.35%	6.74%	2/24/2000	6.18%
10/8/1997	6.373	6.37%	6.74%	2/25/2000	6.18%
10/7/1997	6.233	6.23%	6.74%	2/28/2000	6.18%
10/6/1997	6.259	6.26%	6.75%	2/29/2000	6.19%
10/3/1997	6.294	6.29%	6.75%	3/1/2000	6.19%
10/2/1997	6.295	6.30%	6.75%	3/2/2000	6.19%
10/1/1997	6.322	6.32%	6.75%	3/3/2000	6.19%
9/30/1997	6.399	6.40%	6.75%	3/6/2000	6.19%
9/29/1997	6.384	6.38%	6.75%	3/7/2000	6.19%
9/26/1997	6.367	6.37%	6.75%	3/8/2000	6.19%
9/25/1997	6.403	6.40%	6.76%	3/9/2000	6.20%
9/24/1997	6.316	6.32%	6.76%	3/10/2000	6.20%
9/23/1997	6.385	6.39%	6.76%	3/13/2000	6.20%
9/22/1997	6.352	6.35%	6.76%	3/14/2000	6.20%
9/19/1997	6.378	6.38%	6.76%	3/15/2000	6.20%
9/18/1997	6.401	6.40%	6.76%	3/16/2000	6.20%
9/17/1997	6.399	6.40%	6.76%	3/17/2000	6.20%
9/16/1997	6.406	6.41%	6.76%	3/20/2000	6.20%
9/15/1997	6.574	6.57%	6.76%	3/21/2000	6.20%
9/12/1997	6.587	6.59%	6.76%	3/22/2000	6.20%
9/11/1997	6.692	6.69%	6.76%	3/23/2000	6.20%
9/10/1997	6.658	6.66%	6.76%	3/24/2000	6.20%
9/9/1997	6.626	6.63%	6.76%	3/27/2000	6.20%
9/8/1997	6.612	6.61%	6.76%	3/28/2000	6.20%
9/5/1997	6.642	6.64%	6.76%	3/29/2000	6.19%
9/4/1997	6.611	6.61%	6.76%	3/30/2000	6.19%
9/3/1997	6.601	6.60%	6.76%	3/31/2000	6.19%
9/2/1997	6.559	6.56%	6.76%	4/3/2000	6.19%

9/1/1997	6.607	6.61%	6.75%	4/4/2000	6.19%
8/29/1997	6.611	6.61%	6.75%	4/5/2000	6.19%
8/28/1997	6.573	6.57%	6.75%	4/6/2000	6.19%
8/27/1997	6.651	6.65%	6.75%	4/7/2000	6.18%
8/26/1997	6.645	6.65%	6.75%	4/10/2000	6.18%
8/25/1997	6.668	6.67%	6.75%	4/11/2000	6.18%
8/22/1997	6.649	6.65%	6.75%	4/12/2000	6.18%
8/21/1997	6.621	6.62%	6.75%	4/13/2000	6.18%
8/20/1997	6.54	6.54%	6.75%	4/14/2000	6.18%
8/19/1997	6.51	6.51%	6.75%	4/17/2000	6.18%
8/18/1997	6.523	6.52%	6.75%	4/18/2000	6.18%
8/15/1997	6.546	6.55%	6.75%	4/19/2000	6.18%
8/14/1997	6.55	6.55%	6.75%	4/20/2000	6.18%
8/13/1997	6.626	6.63%	6.75%	4/21/2000	6.18%
8/12/1997	6.671	6.67%	6.75%	4/24/2000	6.18%
8/11/1997	6.636	6.64%	6.75%	4/25/2000	6.18%
8/8/1997	6.635	6.64%	6.75%	4/26/2000	6.18%
8/7/1997	6.529	6.53%	6.75%	4/27/2000	6.18%
8/6/1997	6.479	6.48%	6.75%	4/28/2000	6.18%
8/5/1997	6.491	6.49%	6.75%	5/1/2000	6.18%
8/4/1997	6.478	6.48%	6.75%	5/2/2000	6.18%
8/1/1997	6.454	6.45%	6.75%	5/3/2000	6.18%
7/31/1997	6.298	6.30%	6.75%	5/4/2000	6.18%
7/30/1997	6.324	6.32%	6.75%	5/5/2000	6.18%
7/29/1997	6.385	6.39%	6.76%	5/8/2000	6.18%
7/28/1997	6.405	6.41%	6.76%	5/9/2000	6.18%
7/25/1997	6.454	6.45%	6.76%	5/10/2000	6.18%
7/24/1997	6.437	6.44%	6.76%	5/11/2000	6.18%
7/23/1997	6.436	6.44%	6.77%	5/12/2000	6.18%
7/22/1997	6.419	6.42%	6.77%	5/15/2000	6.18%
7/21/1997	6.54	6.54%	6.77%	5/16/2000	6.18%
7/18/1997	6.53	6.53%	6.77%	5/17/2000	6.18%
7/17/1997	6.492	6.49%	6.77%	5/18/2000	6.18%
7/16/1997	6.478	6.48%	6.77%	5/19/2000	6.18%
7/15/1997	6.543	6.54%	6.78%	5/22/2000	6.18%
7/14/1997	6.556	6.56%	6.78%	5/23/2000	6.18%
7/11/1997	6.529	6.53%	6.78%	5/24/2000	6.18%
7/10/1997	6.562	6.56%	6.78%	5/25/2000	6.18%
7/9/1997	6.565	6.57%	6.78%	5/26/2000	6.18%
7/8/1997	6.581	6.58%	6.78%	5/29/2000	6.18%
7/7/1997	6.579	6.58%	6.78%	5/30/2000	6.18%
7/4/1997	6.627	6.63%	6.79%	5/31/2000	6.18%
7/3/1997	6.627	6.63%	6.79%	6/1/2000	6.18%
7/2/1997	6.706	6.71%	6.79%	6/2/2000	6.18%
7/1/1997	6.741	6.74%	6.79%	6/5/2000	6.18%
6/30/1997	6.785	6.79%	6.79%	6/6/2000	6.18%
6/27/1997	6.742	6.74%	6.79%	6/7/2000	6.18%

6/26/1997	6.783	6.78%	6.79%	6/8/2000	6.18%
6/25/1997	6.737	6.74%	6.79%	6/9/2000	6.18%
6/24/1997	6.692	6.69%	6.80%	6/12/2000	6.18%
6/23/1997	6.708	6.71%	6.80%	6/13/2000	6.18%
6/20/1997	6.661	6.66%	6.80%	6/14/2000	6.18%
6/19/1997	6.679	6.68%	6.80%	6/15/2000	6.18%
6/18/1997	6.685	6.69%	6.80%	6/16/2000	6.18%
6/17/1997	6.724	6.72%	6.80%	6/19/2000	6.18%
6/16/1997	6.699	6.70%	6.81%	6/20/2000	6.17%
6/13/1997	6.724	6.72%	6.81%	6/21/2000	6.17%
6/12/1997	6.777	6.78%	6.81%	6/22/2000	6.17%
6/11/1997	6.831	6.83%	6.81%	6/23/2000	6.17%
6/10/1997	6.84	6.84%	6.81%	6/26/2000	6.17%
6/9/1997	6.826	6.83%	6.81%	6/27/2000	6.17%
6/6/1997	6.774	6.77%	6.82%	6/28/2000	6.17%
6/5/1997	6.879	6.88%	6.82%	6/29/2000	6.17%
6/4/1997	6.881	6.88%	6.82%	6/30/2000	6.17%
6/3/1997	6.87	6.87%	6.82%	7/3/2000	6.17%
6/2/1997	6.901	6.90%	6.82%	7/5/2000	6.17%
5/30/1997	6.906	6.91%	6.82%	7/6/2000	6.17%
5/29/1997	6.976	6.98%	6.82%	7/7/2000	6.17%
5/28/1997	7.03	7.03%	6.82%	7/10/2000	6.17%
5/27/1997	7.026	7.03%	6.82%	7/11/2000	6.16%
5/26/1997	6.986	6.99%	6.82%	7/12/2000	6.16%
5/23/1997	6.987	6.99%	6.82%	7/13/2000	6.16%
5/22/1997	6.988	6.99%	6.82%	7/14/2000	6.16%
5/21/1997	6.961	6.96%	6.81%	7/17/2000	6.16%
5/20/1997	6.904	6.90%	6.81%	7/18/2000	6.16%
5/19/1997	6.92	6.92%	6.81%	7/19/2000	6.16%
5/16/1997	6.9	6.90%	6.81%	7/20/2000	6.15%
5/15/1997	6.869	6.87%	6.81%	7/21/2000	6.15%
5/14/1997	6.879	6.88%	6.81%	7/24/2000	6.15%
5/13/1997	6.923	6.92%	6.81%	7/25/2000	6.15%
5/12/1997	6.886	6.89%	6.81%	7/26/2000	6.14%
5/9/1997	6.891	6.89%	6.81%	7/27/2000	6.14%
5/8/1997	6.93	6.93%	6.81%	7/28/2000	6.14%
5/7/1997	6.962	6.96%	6.81%	7/31/2000	6.13%
5/6/1997	6.884	6.88%	6.81%	8/1/2000	6.13%
5/5/1997	6.876	6.88%	6.81%	8/2/2000	6.13%
5/2/1997	6.875	6.88%	6.81%	8/3/2000	6.12%
5/1/1997	6.916	6.92%	6.81%	8/4/2000	6.12%
4/30/1997	6.957	6.96%	6.81%	8/7/2000	6.12%
4/29/1997	6.985	6.99%	6.81%	8/8/2000	6.12%
4/28/1997	7.114	7.11%	6.81%	8/9/2000	6.12%
4/25/1997	7.142	7.14%	6.81%	8/10/2000	6.11%
4/24/1997	7.133	7.13%	6.81%	8/11/2000	6.11%
4/23/1997	7.092	7.09%	6.81%	8/14/2000	6.11%

4/22/1997	7.039	7.04%	6.81%	8/15/2000	6.11%
4/21/1997	7.092	7.09%	6.81%	8/16/2000	6.11%
4/18/1997	7.053	7.05%	6.81%	8/17/2000	6.10%
4/17/1997	7.069	7.07%	6.81%	8/18/2000	6.10%
4/16/1997	7.1	7.10%	6.81%	8/21/2000	6.10%
4/15/1997	7.093	7.09%	6.81%	8/22/2000	6.10%
4/14/1997	7.169	7.17%	6.81%	8/23/2000	6.10%
4/11/1997	7.166	7.17%	6.81%	8/24/2000	6.09%
4/10/1997	7.109	7.11%	6.81%	8/25/2000	6.09%
4/9/1997	7.102	7.10%	6.81%	8/28/2000	6.09%
4/8/1997	7.1	7.10%	6.81%	8/29/2000	6.09%
4/7/1997	7.072	7.07%	6.81%	8/30/2000	6.09%
4/4/1997	7.124	7.12%	6.80%	8/31/2000	6.08%
4/3/1997	7.07	7.07%	6.80%	9/1/2000	6.08%
4/2/1997	7.077	7.08%	6.80%	9/4/2000	6.08%
4/1/1997	7.076	7.08%	6.80%	9/5/2000	6.07%
3/31/1997	7.096	7.10%	6.80%	9/6/2000	6.07%
3/28/1997	7.088	7.09%	6.80%	9/7/2000	6.07%
3/27/1997	7.09	7.09%	6.80%	9/8/2000	6.07%
3/26/1997	6.979	6.98%	6.80%	9/11/2000	6.06%
3/25/1997	6.968	6.97%	6.80%	9/12/2000	6.06%
3/24/1997	6.925	6.93%	6.80%	9/13/2000	6.06%
3/21/1997	6.968	6.97%	6.80%	9/14/2000	6.06%
3/20/1997	6.956	6.96%	6.81%	9/15/2000	6.05%
3/19/1997	6.988	6.99%	6.81%	9/18/2000	6.05%
3/18/1997	6.959	6.96%	6.81%	9/19/2000	6.05%
3/17/1997	6.957	6.96%	6.81%	9/20/2000	6.05%
3/14/1997	6.941	6.94%	6.81%	9/21/2000	6.05%
3/13/1997	6.959	6.96%	6.81%	9/22/2000	6.05%
3/12/1997	6.885	6.89%	6.81%	9/25/2000	6.04%
3/11/1997	6.852	6.85%	6.81%	9/26/2000	6.04%
3/10/1997	6.814	6.81%	6.81%	9/27/2000	6.04%
3/7/1997	6.814	6.81%	6.81%	9/28/2000	6.03%
3/6/1997	6.885	6.89%	6.81%	9/29/2000	6.03%
3/5/1997	6.828	6.83%	6.81%	10/2/2000	6.03%
3/4/1997	6.869	6.87%	6.81%	10/3/2000	6.03%
3/3/1997	6.832	6.83%	6.81%	10/4/2000	6.02%
2/28/1997	6.803	6.80%	6.81%	10/5/2000	6.02%
2/27/1997	6.805	6.81%	6.81%	10/6/2000	6.02%
2/26/1997	6.778	6.78%	6.81%	10/9/2000	6.01%
2/25/1997	6.658	6.66%	6.81%	10/10/2000	6.01%
2/24/1997	6.655	6.66%	6.81%	10/11/2000	6.01%
2/21/1997	6.643	6.64%	6.82%	10/12/2000	6.00%
2/20/1997	6.656	6.66%	6.82%	10/13/2000	6.00%
2/19/1997	6.582	6.58%	6.82%	10/16/2000	6.00%
2/18/1997	6.546	6.55%	6.82%	10/17/2000	5.99%
2/17/1997	6.53	6.53%	6.82%	10/18/2000	5.99%

2/14/1997	6.525	6.53%	6.82%	10/19/2000	5.98%
2/13/1997	6.625	6.63%	6.82%	10/20/2000	5.98%
2/12/1997	6.708	6.71%	6.83%	10/23/2000	5.97%
2/11/1997	6.705	6.71%	6.83%	10/24/2000	5.97%
2/10/1997	6.703	6.70%	6.83%	10/25/2000	5.96%
2/7/1997	6.704	6.70%	6.83%	10/26/2000	5.96%
2/6/1997	6.757	6.76%	6.83%	10/27/2000	5.95%
2/5/1997	6.755	6.76%	6.83%	10/30/2000	5.95%
2/4/1997	6.705	6.71%	6.84%	10/31/2000	5.94%
2/3/1997	6.739	6.74%	6.84%	11/1/2000	5.94%
1/31/1997	6.789	6.79%	6.84%	11/2/2000	5.94%
1/30/1997	6.872	6.87%	6.84%	11/3/2000	5.93%
1/29/1997	6.909	6.91%	6.84%	11/6/2000	5.93%
1/28/1997	6.922	6.92%	6.84%	11/7/2000	5.93%
1/27/1997	6.942	6.94%	6.84%	11/8/2000	5.92%
1/24/1997	6.89	6.89%	6.83%	11/9/2000	5.92%
1/23/1997	6.86	6.86%	6.83%	11/10/2000	5.92%
1/22/1997	6.834	6.83%	6.83%	11/13/2000	5.92%
1/21/1997	6.784	6.78%	6.83%	11/14/2000	5.92%
1/20/1997	6.828	6.83%	6.83%	11/15/2000	5.91%
1/17/1997	6.822	6.82%	6.83%	11/16/2000	5.91%
1/16/1997	6.825	6.83%	6.83%	11/17/2000	5.91%
1/15/1997	6.793	6.79%	6.83%	11/20/2000	5.90%
1/14/1997	6.772	6.77%	6.83%	11/21/2000	5.90%
1/13/1997	6.853	6.85%	6.83%	11/22/2000	5.90%
1/10/1997	6.845	6.85%	6.83%	11/23/2000	5.90%
1/9/1997	6.759	6.76%	6.83%	11/24/2000	5.89%
1/8/1997	6.845	6.85%	6.83%	11/27/2000	5.89%
1/7/1997	6.789	6.79%	6.83%	11/28/2000	5.89%
1/6/1997	6.773	6.77%	6.83%	11/29/2000	5.89%
1/3/1997	6.732	6.73%	6.83%	11/30/2000	5.88%
1/2/1997	6.739	6.74%	6.83%	12/1/2000	5.88%
1/1/1997	6.641	6.64%	6.83%	12/4/2000	5.88%
12/31/1996	6.642	6.64%	6.83%	12/5/2000	5.88%
12/30/1996	6.54	6.54%	6.83%	12/6/2000	5.87%
12/27/1996	6.562	6.56%	6.83%	12/7/2000	5.87%
12/26/1996	6.584	6.58%	6.83%	12/8/2000	5.87%
12/25/1996	6.583	6.58%	6.83%	12/11/2000	5.86%
12/24/1996	6.585	6.59%	6.83%	12/12/2000	5.86%
12/23/1996	6.581	6.58%	6.83%	12/13/2000	5.86%
12/20/1996	6.606	6.61%	6.83%	12/14/2000	5.85%
12/19/1996	6.582	6.58%	6.83%	12/15/2000	5.85%
12/18/1996	6.703	6.70%	6.83%	12/18/2000	5.85%
12/17/1996	6.655	6.66%	6.83%	12/19/2000	5.84%
12/16/1996	6.625	6.63%	6.83%	12/20/2000	5.84%
12/13/1996	6.572	6.57%	6.83%	12/21/2000	5.84%
12/12/1996	6.625	6.63%	6.84%	12/22/2000	5.83%

12/11/1996	6.63	6.63%	6.83%	12/25/2000	5.83%
12/10/1996	6.496	6.50%	6.83%	12/26/2000	5.83%
12/9/1996	6.462	6.46%	6.83%	12/27/2000	5.82%
12/6/1996	6.511	6.51%	6.83%	12/28/2000	5.82%
12/5/1996	6.508	6.51%	6.83%	12/29/2000	5.82%
12/4/1996	6.394	6.39%	6.83%	1/1/2001	5.82%
12/3/1996	6.362	6.36%	6.83%	1/2/2001	5.81%
12/2/1996	6.36	6.36%	6.83%	1/3/2001	5.81%
11/29/1996	6.35	6.35%	6.83%	1/4/2001	5.81%
11/28/1996	6.435	6.44%	6.83%	1/5/2001	5.81%
11/27/1996	6.432	6.43%	6.83%	1/8/2001	5.80%
11/26/1996	6.445	6.45%	6.83%	1/9/2001	5.80%
11/25/1996	6.426	6.43%	6.83%	1/10/2001	5.80%
11/22/1996	6.436	6.44%	6.83%	1/11/2001	5.80%
11/21/1996	6.415	6.42%	6.83%	1/12/2001	5.80%
11/20/1996	6.409	6.41%	6.83%	1/16/2001	5.80%
11/19/1996	6.433	6.43%	6.83%	1/17/2001	5.80%
11/18/1996	6.466	6.47%	6.83%	1/18/2001	5.80%
11/15/1996	6.457	6.46%	6.82%	1/19/2001	5.79%
11/14/1996	6.419	6.42%	6.82%	1/22/2001	5.79%
11/13/1996	6.455	6.46%	6.82%	1/23/2001	5.79%
11/12/1996	6.443	6.44%	6.82%	1/24/2001	5.79%
11/11/1996	6.512	6.51%	6.82%	1/25/2001	5.79%
11/8/1996	6.506	6.51%	6.82%	1/26/2001	5.79%
11/7/1996	6.531	6.53%	6.81%	1/29/2001	5.79%
11/6/1996	6.615	6.62%	6.81%	1/30/2001	5.79%
11/5/1996	6.585	6.59%	6.81%	1/31/2001	5.79%
11/4/1996	6.66	6.66%	6.81%	2/1/2001	5.78%
11/1/1996	6.679	6.68%	6.80%	2/2/2001	5.78%
10/31/1996	6.642	6.64%	6.80%	2/5/2001	5.78%
10/30/1996	6.703	6.70%	6.80%	2/6/2001	5.78%
10/29/1996	6.678	6.68%	6.79%	2/7/2001	5.77%
10/28/1996	6.834	6.83%	6.79%	2/8/2001	5.77%
10/25/1996	6.815	6.82%	6.79%	2/9/2001	5.77%
10/24/1996	6.852	6.85%	6.78%	2/12/2001	5.76%
10/23/1996	6.826	6.83%	6.78%	2/13/2001	5.76%
10/22/1996	6.849	6.85%	6.77%	2/14/2001	5.76%
10/21/1996	6.808	6.81%	6.77%	2/15/2001	5.75%
10/18/1996	6.801	6.80%	6.77%	2/16/2001	5.75%
10/17/1996	6.793	6.79%	6.76%	2/19/2001	5.75%
10/16/1996	6.857	6.86%	6.76%	2/20/2001	5.74%
10/15/1996	6.84	6.84%	6.76%	2/21/2001	5.74%
10/14/1996	6.844	6.84%	6.75%	2/22/2001	5.74%
10/11/1996	6.845	6.85%	6.75%	2/23/2001	5.73%
10/10/1996	6.882	6.88%	6.75%	2/26/2001	5.73%
10/9/1996	6.829	6.83%	6.74%	2/27/2001	5.72%
10/8/1996	6.804	6.80%	6.74%	2/28/2001	5.72%

10/7/1996	6.788	6.79%	6.73%	3/1/2001	5.72%
10/4/1996	6.741	6.74%	6.73%	3/2/2001	5.71%
10/3/1996	6.833	6.83%	6.72%	3/5/2001	5.71%
10/2/1996	6.839	6.84%	6.72%	3/6/2001	5.70%
10/1/1996	6.874	6.87%	6.72%	3/7/2001	5.70%
9/30/1996	6.923	6.92%	6.71%	3/8/2001	5.70%
9/27/1996	6.908	6.91%	6.71%	3/9/2001	5.69%
9/26/1996	6.888	6.89%	6.70%	3/12/2001	5.69%
9/25/1996	6.925	6.93%	6.70%	3/13/2001	5.69%
9/24/1996	6.984	6.98%	6.70%	3/14/2001	5.68%
9/23/1996	7.025	7.03%	6.69%	3/15/2001	5.68%
9/20/1996	7.043	7.04%	6.69%	3/16/2001	5.68%
9/19/1996	7.043	7.04%	6.68%	3/19/2001	5.67%
9/18/1996	7.009	7.01%	6.68%	3/20/2001	5.67%
9/17/1996	7.024	7.02%	6.67%	3/21/2001	5.67%
9/16/1996	6.95	6.95%	6.67%	3/22/2001	5.66%
9/13/1996	6.948	6.95%	6.66%	3/23/2001	5.66%
9/12/1996	7.075	7.08%	6.66%	3/26/2001	5.66%
9/11/1996	7.107	7.11%	6.65%	3/27/2001	5.66%
9/10/1996	7.111	7.11%	6.65%	3/28/2001	5.65%
9/9/1996	7.069	7.07%	6.64%	3/29/2001	5.65%
9/6/1996	7.11	7.11%	6.64%	3/30/2001	5.65%
9/5/1996	7.152	7.15%	6.63%	4/2/2001	5.65%
9/4/1996	7.098	7.10%	6.63%	4/3/2001	5.64%
9/3/1996	7.053	7.05%	6.62%	4/4/2001	5.64%
9/2/1996	7.115	7.12%	6.62%	4/5/2001	5.64%
8/30/1996	7.118	7.12%	6.61%	4/6/2001	5.64%
8/29/1996	7.038	7.04%	6.61%	4/9/2001	5.64%
8/28/1996	6.977	6.98%	6.61%	4/10/2001	5.63%
8/27/1996	6.97	6.97%	6.60%	4/11/2001	5.63%
8/26/1996	6.997	7.00%	6.60%	4/12/2001	5.63%
8/23/1996	6.955	6.96%	6.60%	4/13/2001	5.63%
8/22/1996	6.841	6.84%	6.59%	4/16/2001	5.63%
8/21/1996	6.836	6.84%	6.59%	4/17/2001	5.63%
8/20/1996	6.796	6.80%	6.59%	4/18/2001	5.63%
8/19/1996	6.795	6.80%	6.58%	4/19/2001	5.63%
8/16/1996	6.768	6.77%	6.58%	4/20/2001	5.63%
8/15/1996	6.804	6.80%	6.58%	4/23/2001	5.63%
8/14/1996	6.788	6.79%	6.58%	4/24/2001	5.63%
8/13/1996	6.792	6.79%	6.57%	4/25/2001	5.62%
8/12/1996	6.693	6.69%	6.57%	4/26/2001	5.62%
8/9/1996	6.69	6.69%	6.57%	4/27/2001	5.62%
8/8/1996	6.785	6.79%	6.57%	4/30/2001	5.62%
8/7/1996	6.773	6.77%	6.56%	5/1/2001	5.62%
8/6/1996	6.76	6.76%	6.56%	5/2/2001	5.62%
8/5/1996	6.769	6.77%	6.56%	5/3/2001	5.62%
8/2/1996	6.743	6.74%	6.56%	5/4/2001	5.62%

8/1/1996	6.837	6.84%	6.56%	5/7/2001	5.62%
7/31/1996	6.97	6.97%	6.55%	5/8/2001	5.62%
7/30/1996	7.036	7.04%	6.55%	5/9/2001	5.62%
7/29/1996	7.095	7.10%	6.55%	5/10/2001	5.62%
7/26/1996	7.008	7.01%	6.54%	5/11/2001	5.62%
7/25/1996	7.01	7.01%	6.54%	5/14/2001	5.62%
7/24/1996	7.043	7.04%	6.54%	5/15/2001	5.62%
7/23/1996	6.975	6.98%	6.53%	5/16/2001	5.62%
7/22/1996	7.008	7.01%	6.53%	5/17/2001	5.62%
7/19/1996	6.974	6.97%	6.53%	5/18/2001	5.62%
7/18/1996	6.931	6.93%	6.52%	5/21/2001	5.62%
7/17/1996	7.03	7.03%	6.52%	5/22/2001	5.62%
7/16/1996	7.03	7.03%	6.52%	5/23/2001	5.62%
7/15/1996	7.073	7.07%	6.51%	5/24/2001	5.62%
7/12/1996	7.03	7.03%	6.51%	5/25/2001	5.63%
7/11/1996	7.058	7.06%	6.51%	5/28/2001	5.63%
7/10/1996	7.077	7.08%	6.50%	5/29/2001	5.63%
7/9/1996	7.13	7.13%	6.50%	5/30/2001	5.63%
7/8/1996	7.181	7.18%	6.50%	5/31/2001	5.63%
7/5/1996	7.192	7.19%	6.49%	6/1/2001	5.63%
7/4/1996	6.933	6.93%	6.49%	6/4/2001	5.63%
7/3/1996	6.936	6.94%	6.49%	6/5/2001	5.63%
7/2/1996	6.939	6.94%	6.49%	6/6/2001	5.63%
7/1/1996	6.911	6.91%	6.49%	6/7/2001	5.63%
6/28/1996	6.871	6.87%	6.48%	6/8/2001	5.63%
6/27/1996	6.992	6.99%	6.48%	6/11/2001	5.63%
6/26/1996	7.041	7.04%	6.48%	6/12/2001	5.63%
6/25/1996	7.046	7.05%	6.48%	6/13/2001	5.63%
6/24/1996	7.088	7.09%	6.47%	6/14/2001	5.63%
6/21/1996	7.096	7.10%	6.47%	6/15/2001	5.63%
6/20/1996	7.109	7.11%	6.47%	6/18/2001	5.63%
6/19/1996	7.108	7.11%	6.47%	6/19/2001	5.63%
6/18/1996	7.103	7.10%	6.46%	6/20/2001	5.63%
6/17/1996	7.071	7.07%	6.46%	6/21/2001	5.63%
6/14/1996	7.089	7.09%	6.46%	6/22/2001	5.63%
6/13/1996	7.129	7.13%	6.45%	6/25/2001	5.62%
6/12/1996	7.192	7.19%	6.45%	6/26/2001	5.62%
6/11/1996	7.123	7.12%	6.45%	6/27/2001	5.62%
6/10/1996	7.127	7.13%	6.45%	6/28/2001	5.62%
6/7/1996	7.031	7.03%	6.44%	6/29/2001	5.62%
6/6/1996	6.896	6.90%	6.44%	7/2/2001	5.62%
6/5/1996	6.948	6.95%	6.44%	7/3/2001	5.62%
6/4/1996	7.001	7.00%	6.44%	7/4/2001	5.62%
6/3/1996	7.008	7.01%	6.44%	7/5/2001	5.62%
5/31/1996	6.989	6.99%	6.44%	7/6/2001	5.61%
5/30/1996	6.932	6.93%	6.43%	7/9/2001	5.61%
5/29/1996	6.941	6.94%	6.43%	7/10/2001	5.61%

5/28/1996	6.855	6.86%	6.43%	7/11/2001	5.61%
5/27/1996	6.836	6.84%	6.43%	7/12/2001	5.61%
5/24/1996	6.834	6.83%	6.43%	7/13/2001	5.61%
5/23/1996	6.859	6.86%	6.43%	7/16/2001	5.61%
5/22/1996	6.815	6.82%	6.43%	7/17/2001	5.61%
5/21/1996	6.85	6.85%	6.44%	7/18/2001	5.60%
5/20/1996	6.837	6.84%	6.44%	7/19/2001	5.60%
5/17/1996	6.833	6.83%	6.44%	7/20/2001	5.60%
5/16/1996	6.913	6.91%	6.44%	7/23/2001	5.60%
5/15/1996	6.845	6.85%	6.44%	7/24/2001	5.60%
5/14/1996	6.845	6.85%	6.44%	7/25/2001	5.60%
5/13/1996	6.897	6.90%	6.44%	7/26/2001	5.60%
5/10/1996	6.928	6.93%	6.44%	7/27/2001	5.60%
5/9/1996	7.017	7.02%	6.44%	7/30/2001	5.59%
5/8/1996	6.96	6.96%	6.44%	7/31/2001	5.59%
5/7/1996	7.078	7.08%	6.44%	8/1/2001	5.59%
5/6/1996	7.059	7.06%	6.44%	8/2/2001	5.59%
5/3/1996	7.117	7.12%	6.43%	8/3/2001	5.59%
5/2/1996	7.059	7.06%	6.43%	8/6/2001	5.59%
5/1/1996	6.91	6.91%	6.43%	8/7/2001	5.59%
4/30/1996	6.906	6.91%	6.43%	8/8/2001	5.59%
4/29/1996	6.836	6.84%	6.43%	8/9/2001	5.59%
4/26/1996	6.789	6.79%	6.43%	8/10/2001	5.59%
4/25/1996	6.795	6.80%	6.43%	8/13/2001	5.58%
4/24/1996	6.822	6.82%	6.43%	8/14/2001	5.58%
4/23/1996	6.779	6.78%	6.43%	8/15/2001	5.58%
4/22/1996	6.75	6.75%	6.43%	8/16/2001	5.58%
4/19/1996	6.786	6.79%	6.43%	8/17/2001	5.58%
4/18/1996	6.829	6.83%	6.43%	8/20/2001	5.57%
4/17/1996	6.806	6.81%	6.43%	8/21/2001	5.57%
4/16/1996	6.792	6.79%	6.43%	8/22/2001	5.57%
4/15/1996	6.79	6.79%	6.43%	8/23/2001	5.57%
4/12/1996	6.802	6.80%	6.43%	8/24/2001	5.57%
4/11/1996	6.935	6.94%	6.43%	8/27/2001	5.57%
4/10/1996	6.947	6.95%	6.42%	8/28/2001	5.56%
4/9/1996	6.832	6.83%	6.42%	8/29/2001	5.56%
4/8/1996	6.87	6.87%	6.42%	8/30/2001	5.56%
4/5/1996	6.824	6.82%	6.42%	8/31/2001	5.56%
4/4/1996	6.67	6.67%	6.42%	9/3/2001	5.56%
4/3/1996	6.625	6.63%	6.42%	9/4/2001	5.56%
4/2/1996	6.597	6.60%	6.42%	9/5/2001	5.56%
4/1/1996	6.631	6.63%	6.42%	9/6/2001	5.55%
3/29/1996	6.667	6.67%	6.42%	9/7/2001	5.55%
3/28/1996	6.723	6.72%	6.42%	9/10/2001	5.55%
3/27/1996	6.679	6.68%	6.41%	9/11/2001	5.55%
3/26/1996	6.579	6.58%	6.41%	9/13/2001	5.55%
3/25/1996	6.58	6.58%	6.41%	9/14/2001	5.55%

3/22/1996	6.655	6.66%	6.41%	9/17/2001	5.55%
3/21/1996	6.62	6.62%	6.41%	9/18/2001	5.55%
3/20/1996	6.634	6.63%	6.41%	9/19/2001	5.55%
3/19/1996	6.715	6.72%	6.41%	9/20/2001	5.55%
3/18/1996	6.705	6.71%	6.41%	9/21/2001	5.55%
3/15/1996	6.739	6.74%	6.41%	9/24/2001	5.55%
3/14/1996	6.689	6.69%	6.41%	9/25/2001	5.55%
3/13/1996	6.68	6.68%	6.41%	9/26/2001	5.55%
3/12/1996	6.665	6.67%	6.41%	9/27/2001	5.55%
3/11/1996	6.636	6.64%	6.41%	9/28/2001	5.55%
3/8/1996	6.711	6.71%	6.41%	10/1/2001	5.55%
3/7/1996	6.459	6.46%	6.41%	10/2/2001	5.55%
3/6/1996	6.453	6.45%	6.41%	10/3/2001	5.55%
3/5/1996	6.382	6.38%	6.41%	10/4/2001	5.55%
3/4/1996	6.333	6.33%	6.41%	10/5/2001	5.55%
3/1/1996	6.367	6.37%	6.41%	10/8/2001	5.55%
2/29/1996	6.469	6.47%	6.42%	10/9/2001	5.55%
2/28/1996	6.473	6.47%	6.42%	10/10/2001	5.55%
2/27/1996	6.476	6.48%	6.42%	10/11/2001	5.55%
2/26/1996	6.454	6.45%	6.42%	10/12/2001	5.55%
2/23/1996	6.405	6.41%	6.42%	10/15/2001	5.55%
2/22/1996	6.343	6.34%	6.43%	10/16/2001	5.55%
2/21/1996	6.371	6.37%	6.43%	10/17/2001	5.55%
2/20/1996	6.395	6.40%	6.43%	10/18/2001	5.55%
2/19/1996	6.239	6.24%	6.43%	10/19/2001	5.54%
2/16/1996	6.243	6.24%	6.44%	10/22/2001	5.54%
2/15/1996	6.167	6.17%	6.44%	10/23/2001	5.54%
2/14/1996	6.089	6.09%	6.44%	10/24/2001	5.54%
2/13/1996	6.03	6.03%	6.45%	10/25/2001	5.54%
2/12/1996	6.034	6.03%	6.45%	10/26/2001	5.54%
2/9/1996	6.098	6.10%	6.46%	10/29/2001	5.54%
2/8/1996	6.147	6.15%	6.46%	10/30/2001	5.54%
2/7/1996	6.155	6.16%	6.47%	10/31/2001	5.53%
2/6/1996	6.13	6.13%	6.47%	11/1/2001	5.53%
2/5/1996	6.158	6.16%	6.48%	11/2/2001	5.52%
2/2/1996	6.163	6.16%	6.49%	11/5/2001	5.52%
2/1/1996	6.07	6.07%	6.49%	11/6/2001	5.52%
1/31/1996	6.028	6.03%	6.50%	11/7/2001	5.51%
1/30/1996	6.036	6.04%	6.50%	11/8/2001	5.51%
1/29/1996	6.093	6.09%	6.51%	11/9/2001	5.51%
1/26/1996	6.044	6.04%	6.52%	11/12/2001	5.50%
1/25/1996	6.113	6.11%	6.52%	11/13/2001	5.50%
1/24/1996	6.036	6.04%	6.53%	11/14/2001	5.50%
1/23/1996	6.093	6.09%	6.54%	11/15/2001	5.50%
1/22/1996	6.043	6.04%	6.54%	11/16/2001	5.49%
1/19/1996	5.973	5.97%	6.55%	11/19/2001	5.49%
1/18/1996	5.985	5.99%	6.56%	11/20/2001	5.49%

1/17/1996	6.01	6.01%	6.56%	11/21/2001	5.49%
1/16/1996	6.057	6.06%	6.57%	11/22/2001	5.49%
1/15/1996	6.148	6.15%	6.58%	11/23/2001	5.49%
1/12/1996	6.147	6.15%	6.58%	11/26/2001	5.49%
1/11/1996	6.149	6.15%	6.59%	11/27/2001	5.49%
1/10/1996	6.182	6.18%	6.59%	11/28/2001	5.49%
1/9/1996	6.112	6.11%	6.60%	11/29/2001	5.49%
1/8/1996	6.043	6.04%	6.61%	11/30/2001	5.49%
1/5/1996	6.044	6.04%	6.61%	12/3/2001	5.49%
1/4/1996	6.032	6.03%	6.62%	12/4/2001	5.49%
1/3/1996	5.957	5.96%	6.63%	12/5/2001	5.49%
1/2/1996	5.962	5.96%	6.63%	12/6/2001	5.49%
1/1/1996	5.95	5.95%	6.64%	12/7/2001	5.49%
12/29/1995	5.948	5.95%	6.65%	12/10/2001	5.49%
12/28/1995	5.984	5.98%	6.66%	12/11/2001	5.49%
12/27/1995	6.009	6.01%	6.66%	12/12/2001	5.49%
12/26/1995	6.039	6.04%	6.67%	12/13/2001	5.49%
12/25/1995	6.066	6.07%	6.68%	12/14/2001	5.49%
12/22/1995	6.063	6.06%	6.68%	12/17/2001	5.49%
12/21/1995	6.088	6.09%	6.69%	12/18/2001	5.49%
12/20/1995	6.123	6.12%	6.70%	12/19/2001	5.50%
12/19/1995	6.114	6.11%	6.70%	12/20/2001	5.50%
12/18/1995	6.2	6.20%	6.71%	12/21/2001	5.50%
12/15/1995	6.097	6.10%	6.72%	12/24/2001	5.50%
12/14/1995	6.086	6.09%	6.72%	12/25/2001	5.50%
12/13/1995	6.082	6.08%	6.73%	12/26/2001	5.50%
12/12/1995	6.051	6.05%	6.74%	12/27/2001	5.50%
12/11/1995	6.046	6.05%	6.74%	12/28/2001	5.50%
12/8/1995	6.053	6.05%	6.75%	12/31/2001	5.50%
12/7/1995	6.077	6.08%	6.76%	1/1/2002	5.50%
12/6/1995	6.032	6.03%	6.77%	1/2/2002	5.50%
12/5/1995	6.05	6.05%	6.77%	1/3/2002	5.51%
12/4/1995	6.026	6.03%	6.78%	1/4/2002	5.51%
12/1/1995	6.086	6.09%	6.79%	1/7/2002	5.51%
11/30/1995	6.131	6.13%	6.80%	1/8/2002	5.51%
11/29/1995	6.197	6.20%	6.80%	1/9/2002	5.51%
11/28/1995	6.228	6.23%	6.81%	1/10/2002	5.51%
11/27/1995	6.222	6.22%	6.82%	1/11/2002	5.50%
11/24/1995	6.249	6.25%	6.82%	1/14/2002	5.50%
11/23/1995	6.278	6.28%	6.83%	1/15/2002	5.50%
11/22/1995	6.281	6.28%	6.84%	1/16/2002	5.50%
11/21/1995	6.266	6.27%	6.84%	1/17/2002	5.50%
11/20/1995	6.246	6.25%	6.85%	1/18/2002	5.50%
11/17/1995	6.232	6.23%	6.86%	1/21/2002	5.50%
11/16/1995	6.223	6.22%	6.86%	1/22/2002	5.50%
11/15/1995	6.291	6.29%	6.87%	1/23/2002	5.50%
11/14/1995	6.285	6.29%	6.88%	1/24/2002	5.50%

11/13/1995	6.277	6.28%	6.88%	1/25/2002	5.49%
11/10/1995	6.337	6.34%	6.89%	1/28/2002	5.49%
11/9/1995	6.283	6.28%	6.90%	1/29/2002	5.49%
11/8/1995	6.254	6.25%	6.90%	1/30/2002	5.49%
11/7/1995	6.308	6.31%	6.91%	1/31/2002	5.49%
11/6/1995	6.293	6.29%	6.92%	2/1/2002	5.49%
11/3/1995	6.283	6.28%	6.93%	2/4/2002	5.48%
11/2/1995	6.244	6.24%	6.93%	2/5/2002	5.48%
11/1/1995	6.297	6.30%	6.94%	2/6/2002	5.48%
10/31/1995	6.328	6.33%	6.95%	2/7/2002	5.48%
10/30/1995	6.353	6.35%	6.96%	2/8/2002	5.48%
10/27/1995	6.355	6.36%	6.97%	2/11/2002	5.47%
10/26/1995	6.392	6.39%	6.97%	2/12/2002	5.47%
10/25/1995	6.324	6.32%	6.98%	2/13/2002	5.47%
10/24/1995	6.326	6.33%	6.99%	2/14/2002	5.47%
10/23/1995	6.393	6.39%	6.99%	2/15/2002	5.47%
10/20/1995	6.361	6.36%	7.00%	2/18/2002	5.47%
10/19/1995	6.306	6.31%	7.01%	2/19/2002	5.46%
10/18/1995	6.33	6.33%	7.02%	2/20/2002	5.46%
10/17/1995	6.284	6.28%	7.02%	2/21/2002	5.46%
10/16/1995	6.304	6.30%	7.03%	2/22/2002	5.46%
10/13/1995	6.304	6.30%	7.04%	2/25/2002	5.46%
10/12/1995	6.386	6.39%	7.05%	2/26/2002	5.45%
10/11/1995	6.433	6.43%	7.06%	2/27/2002	5.45%
10/10/1995	6.441	6.44%	7.06%	2/28/2002	5.45%
10/9/1995	6.419	6.42%	7.07%	3/1/2002	5.45%
10/6/1995	6.42	6.42%	7.08%	3/4/2002	5.45%
10/5/1995	6.417	6.42%	7.08%	3/5/2002	5.44%
10/4/1995	6.431	6.43%	7.09%	3/6/2002	5.44%
10/3/1995	6.455	6.46%	7.10%	3/7/2002	5.44%
10/2/1995	6.476	6.48%	7.10%	3/8/2002	5.44%
9/29/1995	6.501	6.50%	7.11%	3/11/2002	5.44%
9/28/1995	6.586	6.59%	7.12%	3/12/2002	5.44%
9/27/1995	6.577	6.58%	7.12%	3/13/2002	5.44%
9/26/1995	6.575	6.58%	7.13%	3/14/2002	5.44%
9/25/1995	6.58	6.58%	7.14%	3/15/2002	5.44%
9/22/1995	6.584	6.58%	7.14%	3/18/2002	5.44%
9/21/1995	6.556	6.56%	7.15%	3/19/2002	5.44%
9/20/1995	6.469	6.47%	7.16%	3/20/2002	5.44%
9/19/1995	6.485	6.49%	7.16%	3/21/2002	5.45%
9/18/1995	6.53	6.53%	7.17%	3/22/2002	5.45%
9/15/1995	6.479	6.48%	7.18%	3/25/2002	5.45%
9/14/1995	6.467	6.47%	7.18%	3/26/2002	5.45%
9/13/1995	6.521	6.52%	7.19%	3/27/2002	5.45%
9/12/1995	6.501	6.50%	7.20%	3/28/2002	5.45%
9/11/1995	6.588	6.59%	7.20%	3/29/2002	5.45%
9/8/1995	6.587	6.59%	7.21%	4/1/2002	5.45%

9/7/1995	6.599	6.60%	7.22%	4/2/2002	5.45%
9/6/1995	6.593	6.59%	7.23%	4/3/2002	5.45%
9/5/1995	6.566	6.57%	7.23%	4/4/2002	5.45%
9/4/1995	6.61	6.61%	7.24%	4/5/2002	5.45%
9/1/1995	6.616	6.62%	7.25%	4/8/2002	5.45%
8/31/1995	6.647	6.65%	7.25%	4/9/2002	5.45%
8/30/1995	6.698	6.70%	7.26%	4/10/2002	5.45%
8/29/1995	6.714	6.71%	7.27%	4/11/2002	5.45%
8/28/1995	6.702	6.70%	7.27%	4/12/2002	5.45%
8/25/1995	6.704	6.70%	7.28%	4/15/2002	5.45%
8/24/1995	6.814	6.81%	7.29%	4/16/2002	5.45%
8/23/1995	6.908	6.91%	7.29%	4/17/2002	5.45%
8/22/1995	6.885	6.89%	7.30%	4/18/2002	5.45%
8/21/1995	6.871	6.87%	7.31%	4/19/2002	5.45%
8/18/1995	6.897	6.90%	7.31%	4/22/2002	5.45%
8/17/1995	6.899	6.90%	7.32%	4/23/2002	5.45%
8/16/1995	6.886	6.89%	7.32%	4/24/2002	5.45%
8/15/1995	6.894	6.89%	7.33%	4/25/2002	5.45%
8/14/1995	6.954	6.95%	7.34%	4/26/2002	5.45%
8/11/1995	6.99	6.99%	7.34%	4/29/2002	5.45%
8/10/1995	6.953	6.95%	7.35%	4/30/2002	5.45%
8/9/1995	6.919	6.92%	7.35%	5/1/2002	5.45%
8/8/1995	6.886	6.89%	7.36%	5/2/2002	5.45%
8/7/1995	6.89	6.89%	7.37%	5/3/2002	5.45%
8/4/1995	6.908	6.91%	7.37%	5/6/2002	5.45%
8/3/1995	6.931	6.93%	7.38%	5/7/2002	5.45%
8/2/1995	6.859	6.86%	7.38%	5/8/2002	5.45%
8/1/1995	6.898	6.90%	7.39%	5/9/2002	5.45%
7/31/1995	6.846	6.85%	7.39%	5/10/2002	5.45%
7/28/1995	6.9	6.90%	7.40%	5/13/2002	5.45%
7/27/1995	6.844	6.84%	7.40%	5/14/2002	5.46%
7/26/1995	6.881	6.88%	7.41%	5/15/2002	5.46%
7/25/1995	6.822	6.82%	7.42%	5/16/2002	5.46%
7/24/1995	6.879	6.88%	7.42%	5/17/2002	5.46%
7/21/1995	6.962	6.96%	7.43%	5/20/2002	5.46%
7/20/1995	6.863	6.86%	7.43%	5/21/2002	5.46%
7/19/1995	6.861	6.86%	7.43%	5/22/2002	5.46%
7/18/1995	6.758	6.76%	7.44%	5/23/2002	5.46%
7/17/1995	6.676	6.68%	7.45%	5/24/2002	5.46%
7/14/1995	6.604	6.60%	7.45%	5/27/2002	5.46%
7/13/1995	6.555	6.56%	7.46%	5/28/2002	5.46%
7/12/1995	6.543	6.54%	7.46%	5/29/2002	5.47%
7/11/1995	6.581	6.58%	7.47%	5/30/2002	5.47%
7/10/1995	6.519	6.52%	7.48%	5/31/2002	5.47%
7/7/1995	6.524	6.52%	7.49%	6/3/2002	5.47%
7/6/1995	6.507	6.51%	7.49%	6/4/2002	5.47%
7/5/1995	6.603	6.60%	7.50%	6/5/2002	5.47%

7/4/1995	6.634	6.63%	7.50%	6/6/2002	5.47%
7/3/1995	6.632	6.63%	7.51%	6/7/2002	5.47%
6/30/1995	6.617	6.62%	7.52%	6/10/2002	5.47%
6/29/1995	6.642	6.64%	7.52%	6/11/2002	5.47%
6/28/1995	6.509	6.51%	7.53%	6/12/2002	5.47%
6/27/1995	6.55	6.55%	7.53%	6/13/2002	5.47%
6/26/1995	6.549	6.55%	7.54%	6/14/2002	5.47%
6/23/1995	6.5	6.50%	7.55%	6/17/2002	5.48%
6/22/1995	6.468	6.47%	7.55%	6/18/2002	5.48%
6/21/1995	6.548	6.55%	7.56%	6/19/2002	5.48%
6/20/1995	6.584	6.58%	7.56%	6/20/2002	5.48%
6/19/1995	6.571	6.57%	7.57%	6/21/2002	5.48%
6/16/1995	6.615	6.62%	7.58%	6/24/2002	5.48%
6/15/1995	6.604	6.60%	7.58%	6/25/2002	5.48%
6/14/1995	6.572	6.57%	7.59%	6/26/2002	5.47%
6/13/1995	6.549	6.55%	7.59%	6/27/2002	5.47%
6/12/1995	6.703	6.70%	7.60%	6/28/2002	5.47%
6/9/1995	6.726	6.73%	7.60%	7/1/2002	5.47%
6/8/1995	6.608	6.61%	7.60%	7/2/2002	5.47%
6/7/1995	6.548	6.55%	7.61%	7/3/2002	5.47%
6/6/1995	6.506	6.51%	7.61%	7/4/2002	5.47%
6/5/1995	6.516	6.52%	7.62%	7/5/2002	5.47%
6/2/1995	6.529	6.53%	7.62%	7/8/2002	5.47%
6/1/1995	6.62	6.62%	7.63%	7/9/2002	5.47%
5/31/1995	6.649	6.65%	7.63%	7/10/2002	5.47%
5/30/1995	6.66	6.66%	7.64%	7/11/2002	5.47%
5/29/1995	6.752	6.75%	7.64%	7/12/2002	5.47%
5/26/1995	6.748	6.75%	7.64%	7/15/2002	5.48%
5/25/1995	6.718	6.72%	7.65%	7/16/2002	5.48%
5/24/1995	6.744	6.74%	7.65%	7/17/2002	5.48%
5/23/1995	6.862	6.86%	7.65%	7/18/2002	5.48%
5/22/1995	6.916	6.92%	7.66%	7/19/2002	5.48%
5/19/1995	6.917	6.92%	7.66%	7/22/2002	5.47%
5/18/1995	6.894	6.89%	7.66%	7/23/2002	5.47%
5/17/1995	6.864	6.86%	7.67%	7/24/2002	5.47%
5/16/1995	6.861	6.86%	7.67%	7/25/2002	5.47%
5/15/1995	6.944	6.94%	7.67%	7/26/2002	5.47%
5/12/1995	6.989	6.99%	7.68%	7/29/2002	5.47%
5/11/1995	6.993	6.99%	7.68%	7/30/2002	5.47%
5/10/1995	6.996	7.00%	7.68%	7/31/2002	5.47%
5/9/1995	6.943	6.94%	7.68%	8/1/2002	5.47%
5/8/1995	7.029	7.03%	7.69%	8/2/2002	5.47%
5/5/1995	7.018	7.02%	7.69%	8/5/2002	5.47%
5/4/1995	7.163	7.16%	7.69%	8/6/2002	5.47%
5/3/1995	7.242	7.24%	7.69%	8/7/2002	5.48%
5/2/1995	7.311	7.31%	7.69%	8/8/2002	5.48%
5/1/1995	7.344	7.34%	7.69%	8/9/2002	5.48%

4/28/1995	7.336	7.34%	7.70%	8/12/2002	5.48%
4/27/1995	7.336	7.34%	7.70%	8/13/2002	5.48%
4/26/1995	7.319	7.32%	7.70%	8/14/2002	5.48%
4/25/1995	7.322	7.32%	7.70%	8/15/2002	5.48%
4/24/1995	7.312	7.31%	7.70%	8/16/2002	5.48%
4/21/1995	7.333	7.33%	7.70%	8/19/2002	5.48%
4/20/1995	7.345	7.35%	7.70%	8/20/2002	5.48%
4/19/1995	7.363	7.36%	7.70%	8/21/2002	5.48%
4/18/1995	7.386	7.39%	7.70%	8/22/2002	5.48%
4/17/1995	7.374	7.37%	7.71%	8/23/2002	5.48%
4/14/1995	7.335	7.34%	7.71%	8/26/2002	5.48%
4/13/1995	7.329	7.33%	7.71%	8/27/2002	5.48%
4/12/1995	7.353	7.35%	7.71%	8/28/2002	5.48%
4/11/1995	7.371	7.37%	7.71%	8/29/2002	5.48%
4/10/1995	7.392	7.39%	7.71%	8/30/2002	5.47%
4/7/1995	7.39	7.39%	7.71%	9/2/2002	5.47%
4/6/1995	7.347	7.35%	7.71%	9/3/2002	5.47%
4/5/1995	7.37	7.37%	7.72%	9/4/2002	5.47%
4/4/1995	7.378	7.38%	7.72%	9/5/2002	5.46%
4/3/1995	7.386	7.39%	7.72%	9/6/2002	5.46%
3/31/1995	7.431	7.43%	7.72%	9/9/2002	5.46%
3/30/1995	7.414	7.41%	7.72%	9/10/2002	5.46%
3/29/1995	7.375	7.38%	7.72%	9/11/2002	5.46%
3/28/1995	7.39	7.39%	7.72%	9/12/2002	5.45%
3/27/1995	7.32	7.32%	7.72%	9/13/2002	5.45%
3/24/1995	7.363	7.36%	7.72%	9/16/2002	5.44%
3/23/1995	7.444	7.44%	7.72%	9/17/2002	5.44%
3/22/1995	7.445	7.45%	7.72%	9/18/2002	5.44%
3/21/1995	7.445	7.45%	7.72%	9/19/2002	5.43%
3/20/1995	7.395	7.40%	7.72%	9/20/2002	5.43%
3/17/1995	7.367	7.37%	7.72%	9/23/2002	5.42%
3/16/1995	7.374	7.37%	7.72%	9/24/2002	5.42%
3/15/1995	7.359	7.36%	7.72%	9/25/2002	5.42%
3/14/1995	7.36	7.36%	7.72%	9/26/2002	5.41%
3/13/1995	7.451	7.45%	7.72%	9/27/2002	5.41%
3/10/1995	7.462	7.46%	7.72%	9/30/2002	5.40%
3/9/1995	7.51	7.51%	7.71%	10/1/2002	5.40%
3/8/1995	7.544	7.54%	7.71%	10/2/2002	5.40%
3/7/1995	7.626	7.63%	7.71%	10/3/2002	5.39%
3/6/1995	7.587	7.59%	7.71%	10/4/2002	5.39%
3/3/1995	7.541	7.54%	7.71%	10/7/2002	5.38%
3/2/1995	7.487	7.49%	7.71%	10/8/2002	5.38%
3/1/1995	7.448	7.45%	7.71%	10/9/2002	5.38%
2/28/1995	7.443	7.44%	7.71%	10/10/2002	5.37%
2/27/1995	7.468	7.47%	7.71%	10/11/2002	5.37%
2/24/1995	7.528	7.53%	7.71%	10/14/2002	5.36%
2/23/1995	7.549	7.55%	7.71%	10/15/2002	5.36%

2/22/1995	7.537	7.54%	7.71%	10/16/2002	5.36%
2/21/1995	7.611	7.61%	7.70%	10/17/2002	5.36%
2/20/1995	7.59	7.59%	7.70%	10/18/2002	5.36%
2/17/1995	7.586	7.59%	7.70%	10/21/2002	5.36%
2/16/1995	7.571	7.57%	7.70%	10/22/2002	5.35%
2/15/1995	7.556	7.56%	7.70%	10/23/2002	5.35%
2/14/1995	7.61	7.61%	7.70%	10/24/2002	5.35%
2/13/1995	7.667	7.67%	7.70%	10/25/2002	5.35%
2/10/1995	7.668	7.67%	7.70%	10/28/2002	5.35%
2/9/1995	7.682	7.68%	7.70%	10/29/2002	5.35%
2/8/1995	7.642	7.64%	7.70%	10/30/2002	5.35%
2/7/1995	7.641	7.64%	7.70%	10/31/2002	5.34%
2/6/1995	7.642	7.64%	7.70%	11/1/2002	5.34%
2/3/1995	7.626	7.63%	7.69%	11/4/2002	5.34%
2/2/1995	7.741	7.74%	7.69%	11/5/2002	5.34%
2/1/1995	7.746	7.75%	7.69%	11/6/2002	5.34%
1/31/1995	7.698	7.70%	7.69%	11/7/2002	5.33%
1/30/1995	7.753	7.75%	7.68%	11/8/2002	5.33%
1/27/1995	7.73	7.73%	7.68%	11/11/2002	5.33%
1/26/1995	7.843	7.84%	7.68%	11/12/2002	5.32%
1/25/1995	7.872	7.87%	7.68%	11/13/2002	5.32%
1/24/1995	7.925	7.93%	7.67%	11/14/2002	5.32%
1/23/1995	7.906	7.91%	7.67%	11/15/2002	5.32%
1/20/1995	7.891	7.89%	7.67%	11/18/2002	5.31%
1/19/1995	7.821	7.82%	7.66%	11/19/2002	5.31%
1/18/1995	7.773	7.77%	7.66%	11/20/2002	5.31%
1/17/1995	7.773	7.77%	7.66%	11/21/2002	5.31%
1/16/1995	7.792	7.79%	7.66%	11/22/2002	5.30%
1/13/1995	7.792	7.79%	7.65%	11/25/2002	5.30%
1/12/1995	7.881	7.88%	7.65%	11/26/2002	5.30%
1/11/1995	7.838	7.84%	7.65%	11/27/2002	5.30%
1/10/1995	7.869	7.87%	7.64%	11/28/2002	5.30%
1/9/1995	7.882	7.88%	7.64%	11/29/2002	5.30%
1/6/1995	7.86	7.86%	7.64%	12/2/2002	5.29%
1/5/1995	7.882	7.88%	7.64%	12/3/2002	5.29%
1/4/1995	7.851	7.85%	7.63%	12/4/2002	5.29%
1/3/1995	7.919	7.92%	7.63%	12/5/2002	5.29%
1/2/1995	7.879	7.88%	7.62%	12/6/2002	5.29%
12/30/1994	7.881	7.88%	7.62%	12/9/2002	5.28%
12/29/1994	7.838	7.84%	7.62%	12/10/2002	5.28%
12/28/1994	7.829	7.83%	7.61%	12/11/2002	5.28%
12/27/1994	7.76	7.76%	7.61%	12/12/2002	5.27%
12/26/1994	7.827	7.83%	7.60%	12/13/2002	5.27%
12/23/1994	7.827	7.83%	7.60%	12/16/2002	5.27%
12/22/1994	7.853	7.85%	7.59%	12/17/2002	5.26%
12/21/1994	7.841	7.84%	7.59%	12/18/2002	5.26%
12/20/1994	7.847	7.85%	7.58%	12/19/2002	5.25%

12/19/1994	7.841	7.84%	7.58%	12/20/2002	5.25%
12/16/1994	7.854	7.85%	7.57%	12/23/2002	5.25%
12/15/1994	7.868	7.87%	7.57%	12/24/2002	5.24%
12/14/1994	7.865	7.87%	7.56%	12/25/2002	5.24%
12/13/1994	7.854	7.85%	7.56%	12/26/2002	5.23%
12/12/1994	7.924	7.92%	7.55%	12/27/2002	5.23%
12/9/1994	7.858	7.86%	7.55%	12/30/2002	5.22%
12/8/1994	7.864	7.86%	7.54%	12/31/2002	5.22%
12/7/1994	7.892	7.89%	7.54%	1/1/2003	5.21%
12/6/1994	7.847	7.85%	7.53%	1/2/2003	5.21%
12/5/1994	7.927	7.93%	7.53%	1/3/2003	5.20%
12/2/1994	7.905	7.91%	7.52%	1/6/2003	5.20%
12/1/1994	8.019	8.02%	7.51%	1/7/2003	5.19%
11/30/1994	7.999	8.00%	7.51%	1/8/2003	5.19%
11/29/1994	8.034	8.03%	7.50%	1/9/2003	5.19%
11/28/1994	7.981	7.98%	7.49%	1/10/2003	5.18%
11/25/1994	7.931	7.93%	7.49%	1/13/2003	5.18%
11/24/1994	7.95	7.95%	7.48%	1/14/2003	5.18%
11/23/1994	7.953	7.95%	7.47%	1/15/2003	5.17%
11/22/1994	8.044	8.04%	7.47%	1/16/2003	5.17%
11/21/1994	8.127	8.13%	7.46%	1/17/2003	5.17%
11/18/1994	8.131	8.13%	7.45%	1/20/2003	5.16%
11/17/1994	8.125	8.13%	7.44%	1/21/2003	5.16%
11/16/1994	8.094	8.09%	7.43%	1/22/2003	5.15%
11/15/1994	8.047	8.05%	7.42%	1/23/2003	5.15%
11/14/1994	8.075	8.08%	7.42%	1/24/2003	5.15%
11/11/1994	8.149	8.15%	7.41%	1/27/2003	5.14%
11/10/1994	8.149	8.15%	7.40%	1/28/2003	5.14%
11/9/1994	8.11	8.11%	7.39%	1/29/2003	5.14%
11/8/1994	8.125	8.13%	7.38%	1/30/2003	5.13%
11/7/1994	8.164	8.16%	7.37%	1/31/2003	5.13%
11/4/1994	8.159	8.16%	7.36%	2/3/2003	5.12%
11/3/1994	8.098	8.10%	7.35%	2/4/2003	5.12%
11/2/1994	8.097	8.10%	7.34%	2/5/2003	5.12%
11/1/1994	8.061	8.06%	7.33%	2/6/2003	5.11%
10/31/1994	7.97	7.97%	7.33%	2/7/2003	5.11%
10/28/1994	7.958	7.96%	7.32%	2/10/2003	5.11%
10/27/1994	8.046	8.05%	7.31%	2/11/2003	5.10%
10/26/1994	8.067	8.07%	7.30%	2/12/2003	5.10%
10/25/1994	8.046	8.05%	7.29%	2/13/2003	5.09%
10/24/1994	8.046	8.05%	7.28%	2/14/2003	5.09%
10/21/1994	7.978	7.98%	7.27%	2/17/2003	5.09%
10/20/1994	7.991	7.99%	7.27%	2/18/2003	5.08%
10/19/1994	7.889	7.89%	7.26%	2/19/2003	5.08%
10/18/1994	7.869	7.87%	7.25%	2/20/2003	5.07%
10/17/1994	7.824	7.82%	7.24%	2/21/2003	5.07%
10/14/1994	7.828	7.83%	7.23%	2/24/2003	5.06%

10/13/1994	7.854	7.85%	7.22%	2/25/2003	5.06%
10/12/1994	7.896	7.90%	7.22%	2/26/2003	5.05%
10/11/1994	7.865	7.87%	7.21%	2/27/2003	5.05%
10/10/1994	7.902	7.90%	7.20%	2/28/2003	5.05%
10/7/1994	7.909	7.91%	7.19%	3/3/2003	5.04%
10/6/1994	7.953	7.95%	7.19%	3/4/2003	5.04%
10/5/1994	7.947	7.95%	7.18%	3/5/2003	5.03%
10/4/1994	7.883	7.88%	7.17%	3/6/2003	5.03%
10/3/1994	7.85	7.85%	7.16%	3/7/2003	5.02%
9/30/1994	7.817	7.82%	7.15%	3/10/2003	5.02%
9/29/1994	7.843	7.84%	7.15%	3/11/2003	5.01%
9/28/1994	7.814	7.81%	7.14%	3/12/2003	5.01%
9/27/1994	7.846	7.85%	7.13%	3/13/2003	5.00%
9/26/1994	7.798	7.80%	7.12%	3/14/2003	5.00%
9/23/1994	7.793	7.79%	7.11%	3/17/2003	4.99%
9/22/1994	7.778	7.78%	7.11%	3/18/2003	4.99%
9/21/1994	7.807	7.81%	7.10%	3/19/2003	4.99%
9/20/1994	7.775	7.78%	7.09%	3/20/2003	4.98%
9/19/1994	7.76	7.76%	7.08%	3/21/2003	4.98%
9/16/1994	7.772	7.77%	7.08%	3/24/2003	4.98%
9/15/1994	7.635	7.64%	7.07%	3/25/2003	4.98%
9/14/1994	7.674	7.67%	7.06%	3/26/2003	4.97%
9/13/1994	7.681	7.68%	7.05%	3/27/2003	4.97%
9/12/1994	7.711	7.71%	7.05%	3/28/2003	4.97%
9/9/1994	7.703	7.70%	7.04%	3/31/2003	4.97%
9/8/1994	7.564	7.56%	7.03%	4/1/2003	4.96%
9/7/1994	7.564	7.56%	7.02%	4/2/2003	4.96%
9/6/1994	7.545	7.55%	7.02%	4/3/2003	4.96%
9/5/1994	7.491	7.49%	7.01%	4/4/2003	4.96%
9/2/1994	7.49	7.49%	7.01%	4/7/2003	4.95%
9/1/1994	7.452	7.45%	7.00%	4/8/2003	4.95%
8/31/1994	7.451	7.45%	6.99%	4/9/2003	4.95%
8/30/1994	7.463	7.46%	6.99%	4/10/2003	4.94%
8/29/1994	7.493	7.49%	6.98%	4/11/2003	4.94%
8/26/1994	7.482	7.48%	6.98%	4/14/2003	4.94%
8/25/1994	7.535	7.54%	6.97%	4/15/2003	4.94%
8/24/1994	7.463	7.46%	6.96%	4/16/2003	4.93%
8/23/1994	7.537	7.54%	6.96%	4/17/2003	4.93%
8/22/1994	7.556	7.56%	6.95%	4/18/2003	4.93%
8/19/1994	7.485	7.49%	6.94%	4/21/2003	4.93%
8/18/1994	7.494	7.49%	6.94%	4/22/2003	4.93%
8/17/1994	7.395	7.40%	6.93%	4/23/2003	4.92%
8/16/1994	7.368	7.37%	6.92%	4/24/2003	4.92%
8/15/1994	7.506	7.51%	6.92%	4/25/2003	4.92%
8/12/1994	7.482	7.48%	6.91%	4/28/2003	4.91%
8/11/1994	7.645	7.65%	6.91%	4/29/2003	4.91%
8/10/1994	7.572	7.57%	6.90%	4/30/2003	4.91%

8/9/1994	7.569	7.57%	6.89%	5/1/2003	4.91%
8/8/1994	7.539	7.54%	6.88%	5/2/2003	4.90%
8/5/1994	7.546	7.55%	6.88%	5/5/2003	4.90%
8/4/1994	7.408	7.41%	6.87%	5/6/2003	4.90%
8/3/1994	7.384	7.38%	6.86%	5/7/2003	4.90%
8/2/1994	7.4	7.40%	6.85%	5/8/2003	4.89%
8/1/1994	7.396	7.40%	6.85%	5/9/2003	4.89%
7/29/1994	7.396	7.40%	6.84%	5/12/2003	4.89%
7/28/1994	7.55	7.55%	6.83%	5/13/2003	4.88%
7/27/1994	7.61	7.61%	6.82%	5/14/2003	4.88%
7/26/1994	7.544	7.54%	6.81%	5/15/2003	4.88%
7/25/1994	7.524	7.52%	6.81%	5/16/2003	4.87%
7/22/1994	7.564	7.56%	6.80%	5/19/2003	4.87%
7/21/1994	7.542	7.54%	6.79%	5/20/2003	4.87%
7/20/1994	7.542	7.54%	6.78%	5/21/2003	4.86%
7/19/1994	7.468	7.47%	6.77%	5/22/2003	4.86%
7/18/1994	7.502	7.50%	6.76%	5/23/2003	4.86%
7/15/1994	7.545	7.55%	6.76%	5/26/2003	4.85%
7/14/1994	7.534	7.53%	6.75%	5/27/2003	4.85%
7/13/1994	7.676	7.68%	6.74%	5/28/2003	4.85%
7/12/1994	7.686	7.69%	6.73%	5/29/2003	4.84%
7/11/1994	7.726	7.73%	6.73%	5/30/2003	4.84%
7/8/1994	7.693	7.69%	6.72%	6/2/2003	4.84%
7/7/1994	7.607	7.61%	6.71%	6/3/2003	4.83%
7/6/1994	7.595	7.60%	6.70%	6/4/2003	4.83%
7/5/1994	7.587	7.59%	6.69%	6/5/2003	4.83%
7/4/1994	7.608	7.61%	6.68%	6/6/2003	4.82%
7/1/1994	7.614	7.61%	6.68%	6/9/2003	4.82%
6/30/1994	7.608	7.61%	6.67%	6/10/2003	4.82%
6/29/1994	7.506	7.51%	6.66%	6/11/2003	4.82%
6/28/1994	7.522	7.52%	6.65%	6/12/2003	4.81%
6/27/1994	7.458	7.46%	6.65%	6/13/2003	4.81%
6/24/1994	7.516	7.52%	6.64%	6/16/2003	4.81%
6/23/1994	7.401	7.40%	6.63%	6/17/2003	4.80%
6/22/1994	7.395	7.40%	6.62%	6/18/2003	4.80%
6/21/1994	7.493	7.49%	6.62%	6/19/2003	4.80%
6/20/1994	7.462	7.46%	6.61%	6/20/2003	4.80%
6/17/1994	7.447	7.45%	6.60%	6/23/2003	4.80%
6/16/1994	7.358	7.36%	6.59%	6/24/2003	4.79%
6/15/1994	7.396	7.40%	6.59%	6/25/2003	4.79%
6/14/1994	7.307	7.31%	6.58%	6/26/2003	4.79%
6/13/1994	7.356	7.36%	6.57%	6/27/2003	4.79%
6/10/1994	7.314	7.31%	6.57%	6/30/2003	4.79%
6/9/1994	7.278	7.28%	6.56%	7/1/2003	4.79%
6/8/1994	7.278	7.28%	6.55%	7/2/2003	4.79%
6/7/1994	7.258	7.26%	6.55%	7/3/2003	4.79%
6/6/1994	7.217	7.22%	6.54%	7/4/2003	4.79%

6/3/1994	7.273	7.27%	6.54%	7/7/2003	4.79%
6/2/1994	7.343	7.34%	6.53%	7/8/2003	4.79%
6/1/1994	7.384	7.38%	6.53%	7/9/2003	4.79%
5/31/1994	7.428	7.43%	6.52%	7/10/2003	4.79%
5/30/1994	7.391	7.39%	6.51%	7/11/2003	4.79%
5/27/1994	7.39	7.39%	6.51%	7/14/2003	4.79%
5/26/1994	7.359	7.36%	6.50%	7/15/2003	4.79%
5/25/1994	7.345	7.35%	6.50%	7/16/2003	4.79%
5/24/1994	7.395	7.40%	6.49%	7/17/2003	4.79%
5/23/1994	7.432	7.43%	6.49%	7/18/2003	4.79%
5/20/1994	7.303	7.30%	6.48%	7/21/2003	4.79%
5/19/1994	7.235	7.24%	6.48%	7/22/2003	4.80%
5/18/1994	7.274	7.27%	6.47%	7/23/2003	4.80%
5/17/1994	7.274	7.27%	6.47%	7/24/2003	4.80%
5/16/1994	7.451	7.45%	6.47%	7/25/2003	4.80%
5/13/1994	7.492	7.49%	6.46%	7/28/2003	4.80%
5/12/1994	7.561	7.56%	6.46%	7/29/2003	4.80%
5/11/1994	7.609	7.61%	6.45%	7/30/2003	4.80%
5/10/1994	7.498	7.50%	6.45%	7/31/2003	4.80%
5/9/1994	7.632	7.63%	6.44%	8/1/2003	4.80%
5/6/1994	7.541	7.54%	6.44%	8/4/2003	4.80%
5/5/1994	7.336	7.34%	6.43%	8/5/2003	4.80%
5/4/1994	7.336	7.34%	6.43%	8/6/2003	4.80%
5/3/1994	7.349	7.35%	6.42%	8/7/2003	4.80%
5/2/1994	7.332	7.33%	6.42%	8/8/2003	4.81%
4/29/1994	7.307	7.31%	6.42%	8/11/2003	4.81%
4/28/1994	7.258	7.26%	6.41%	8/12/2003	4.81%
4/27/1994	7.106	7.11%	6.41%	8/13/2003	4.81%
4/26/1994	7.101	7.10%	6.41%	8/14/2003	4.81%
4/25/1994	7.147	7.15%	6.41%	8/15/2003	4.82%
4/22/1994	7.233	7.23%	6.40%	8/18/2003	4.82%
4/21/1994	7.212	7.21%	6.40%	8/19/2003	4.82%
4/20/1994	7.32	7.32%	6.40%	8/20/2003	4.82%
4/19/1994	7.368	7.37%	6.39%	8/21/2003	4.82%
4/18/1994	7.409	7.41%	6.39%	8/22/2003	4.83%
4/15/1994	7.289	7.29%	6.38%	8/25/2003	4.83%
4/14/1994	7.283	7.28%	6.38%	8/26/2003	4.83%
4/13/1994	7.257	7.26%	6.38%	8/27/2003	4.83%
4/12/1994	7.214	7.21%	6.38%	8/28/2003	4.83%
4/11/1994	7.234	7.23%	6.37%	8/29/2003	4.83%
4/8/1994	7.264	7.26%	6.37%	9/1/2003	4.84%
4/7/1994	7.212	7.21%	6.37%	9/2/2003	4.84%
4/6/1994	7.253	7.25%	6.36%	9/3/2003	4.84%
4/5/1994	7.251	7.25%	6.36%	9/4/2003	4.84%
4/4/1994	7.416	7.42%	6.36%	9/5/2003	4.84%
4/1/1994	7.254	7.25%	6.36%	9/8/2003	4.84%
3/31/1994	7.092	7.09%	6.35%	9/9/2003	4.84%

3/30/1994	7.103	7.10%	6.35%	9/10/2003	4.84%
3/29/1994	7.06	7.06%	6.35%	9/11/2003	4.84%
3/28/1994	6.975	6.98%	6.35%	9/12/2003	4.84%
3/25/1994	7.016	7.02%	6.35%	9/15/2003	4.85%
3/24/1994	6.952	6.95%	6.35%	9/16/2003	4.85%
3/23/1994	6.889	6.89%	6.35%	9/17/2003	4.85%
3/22/1994	6.848	6.85%	6.35%	9/18/2003	4.85%
3/21/1994	6.961	6.96%	6.35%	9/19/2003	4.85%
3/18/1994	6.919	6.92%	6.34%	9/22/2003	4.85%
3/17/1994	6.826	6.83%	6.34%	9/23/2003	4.85%
3/16/1994	6.8	6.80%	6.35%	9/24/2003	4.85%
3/15/1994	6.889	6.89%	6.35%	9/25/2003	4.85%
3/14/1994	6.944	6.94%	6.35%	9/26/2003	4.85%
3/11/1994	6.904	6.90%	6.35%	9/29/2003	4.85%
3/10/1994	6.956	6.96%	6.35%	9/30/2003	4.85%
3/9/1994	6.834	6.83%	6.34%	10/1/2003	4.85%
3/8/1994	6.864	6.86%	6.35%	10/2/2003	4.85%
3/7/1994	6.8	6.80%	6.35%	10/3/2003	4.85%
3/4/1994	6.839	6.84%	6.35%	10/6/2003	4.86%
3/3/1994	6.836	6.84%	6.35%	10/7/2003	4.86%
3/2/1994	6.772	6.77%	6.35%	10/8/2003	4.86%
3/1/1994	6.779	6.78%	6.35%	10/9/2003	4.86%
2/28/1994	6.661	6.66%	6.35%	10/10/2003	4.86%
2/25/1994	6.713	6.71%	6.35%	10/13/2003	4.86%
2/24/1994	6.74	6.74%	6.35%	10/14/2003	4.87%
2/23/1994	6.645	6.65%	6.35%	10/15/2003	4.87%
2/22/1994	6.599	6.60%	6.36%	10/16/2003	4.87%
2/21/1994	6.661	6.66%	6.36%	10/17/2003	4.87%
2/18/1994	6.625	6.63%	6.36%	10/20/2003	4.87%
2/17/1994	6.54	6.54%	6.36%	10/21/2003	4.87%
2/16/1994	6.457	6.46%	6.36%	10/22/2003	4.87%
2/15/1994	6.451	6.45%	6.36%	10/23/2003	4.87%
2/14/1994	6.441	6.44%	6.37%	10/24/2003	4.87%
2/11/1994	6.407	6.41%	6.37%	10/27/2003	4.88%
2/10/1994	6.441	6.44%	6.37%	10/28/2003	4.88%
2/9/1994	6.414	6.41%	6.37%	10/29/2003	4.88%
2/8/1994	6.446	6.45%	6.37%	10/30/2003	4.88%
2/7/1994	6.388	6.39%	6.38%	10/31/2003	4.88%
2/4/1994	6.362	6.36%	6.38%	11/3/2003	4.88%
2/3/1994	6.303	6.30%	6.38%	11/4/2003	4.88%
2/2/1994	6.281	6.28%	6.38%	11/5/2003	4.88%
2/1/1994	6.313	6.31%	6.39%	11/6/2003	4.89%
1/31/1994	6.238	6.24%	6.39%	11/7/2003	4.89%
1/28/1994	6.217	6.22%	6.39%	11/10/2003	4.89%
1/27/1994	6.26	6.26%	6.39%	11/11/2003	4.89%
1/26/1994	6.311	6.31%	6.40%	11/12/2003	4.89%
1/25/1994	6.341	6.34%	6.40%	11/13/2003	4.90%

1/24/1994	6.297	6.30%	6.40%	11/14/2003	4.90%
1/21/1994	6.281	6.28%	6.40%	11/17/2003	4.90%
1/20/1994	6.266	6.27%	6.41%	11/18/2003	4.90%
1/19/1994	6.297	6.30%	6.41%	11/19/2003	4.90%
1/18/1994	6.264	6.26%	6.41%	11/20/2003	4.90%
1/17/1994	6.305	6.31%	6.41%	11/21/2003	4.90%
1/14/1994	6.296	6.30%	6.42%	11/24/2003	4.90%
1/13/1994	6.262	6.26%	6.42%	11/25/2003	4.90%
1/12/1994	6.174	6.17%	6.42%	11/26/2003	4.91%
1/11/1994	6.234	6.23%	6.43%	11/27/2003	4.91%
1/10/1994	6.242	6.24%	6.43%	11/28/2003	4.91%
1/7/1994	6.227	6.23%	6.43%	12/1/2003	4.91%
1/6/1994	6.344	6.34%	6.44%	12/2/2003	4.91%
1/5/1994	6.4	6.40%	6.44%	12/3/2003	4.91%
1/4/1994	6.351	6.35%	6.44%	12/4/2003	4.92%
1/3/1994	6.416	6.42%	6.45%	12/5/2003	4.92%
12/31/1993	6.348	6.35%	6.45%	12/8/2003	4.92%
12/30/1993	6.335	6.34%	6.45%	12/9/2003	4.92%
12/29/1993	6.251	6.25%	6.45%	12/10/2003	4.92%
12/28/1993	6.239	6.24%	6.46%	12/11/2003	4.93%
12/27/1993	6.229	6.23%	6.46%	12/12/2003	4.93%
12/24/1993	6.213	6.21%	6.46%	12/15/2003	4.93%
12/23/1993	6.214	6.21%	6.46%	12/16/2003	4.93%
12/22/1993	6.222	6.22%	6.47%	12/17/2003	4.94%
12/21/1993	6.311	6.31%	6.47%	12/18/2003	4.94%
12/20/1993	6.3	6.30%	6.47%	12/19/2003	4.94%
12/17/1993	6.279	6.28%	6.48%	12/22/2003	4.94%
12/16/1993	6.298	6.30%	6.48%	12/23/2003	4.94%
12/15/1993	6.291	6.29%	6.48%	12/24/2003	4.94%
12/14/1993	6.302	6.30%	6.48%	12/25/2003	4.94%
12/13/1993	6.231	6.23%	6.49%	12/26/2003	4.94%
12/10/1993	6.192	6.19%	6.49%	12/29/2003	4.94%
12/9/1993	6.154	6.15%	6.49%	12/30/2003	4.94%
12/8/1993	6.162	6.16%	6.49%	12/31/2003	4.94%
12/7/1993	6.167	6.17%	6.50%	1/1/2004	4.94%
12/6/1993	6.172	6.17%	6.50%	1/2/2004	4.94%
12/3/1993	6.245	6.25%	6.50%	1/5/2004	4.95%
12/2/1993	6.273	6.27%	6.51%	1/6/2004	4.95%
12/1/1993	6.256	6.26%	6.51%	1/7/2004	4.95%
11/30/1993	6.301	6.30%	6.51%	1/8/2004	4.95%
11/29/1993	6.229	6.23%	6.52%	1/9/2004	4.95%
11/26/1993	6.26	6.26%	6.52%	1/12/2004	4.95%
11/25/1993	6.307	6.31%	6.53%	1/13/2004	4.95%
11/24/1993	6.304	6.30%	6.53%	1/14/2004	4.95%
11/23/1993	6.306	6.31%	6.53%	1/15/2004	4.95%
11/22/1993	6.383	6.38%	6.54%	1/16/2004	4.95%
11/19/1993	6.338	6.34%	6.54%	1/19/2004	4.95%

11/18/1993	6.241	6.24%	6.55%	1/20/2004	4.95%
11/17/1993	6.183	6.18%	6.55%	1/21/2004	4.95%
11/16/1993	6.169	6.17%	6.56%	1/22/2004	4.95%
11/15/1993	6.159	6.16%	6.56%	1/23/2004	4.95%
11/12/1993	6.145	6.15%	6.57%	1/26/2004	4.95%
11/10/1993	6.206	6.21%	6.57%	1/27/2004	4.95%
11/9/1993	6.141	6.14%	6.58%	1/28/2004	4.95%
11/8/1993	6.197	6.20%	6.58%	1/29/2004	4.95%
11/5/1993	6.211	6.21%	6.59%	1/30/2004	4.95%
11/4/1993	6.185	6.19%	6.59%	2/2/2004	4.95%
11/3/1993	6.115	6.12%	6.60%	2/3/2004	4.95%
11/2/1993	6.061	6.06%	6.60%	2/4/2004	4.95%
11/1/1993	6.03	6.03%	6.61%	2/5/2004	4.95%
10/29/1993	5.97	5.97%	6.62%	2/6/2004	4.95%
10/28/1993	5.951	5.95%	6.62%	2/9/2004	4.95%
10/27/1993	6.005	6.01%	6.63%	2/10/2004	4.96%
10/26/1993	5.985	5.99%	6.64%	2/11/2004	4.96%
10/25/1993	6.003	6.00%	6.64%	2/12/2004	4.96%
10/22/1993	5.976	5.98%	6.65%	2/13/2004	4.96%
10/21/1993	5.917	5.92%	6.66%	2/16/2004	4.96%
10/20/1993	5.823	5.82%	6.66%	2/17/2004	4.96%
10/19/1993	5.841	5.84%	6.67%	2/18/2004	4.96%
10/18/1993	5.852	5.85%	6.68%	2/19/2004	4.97%
10/15/1993	5.786	5.79%	6.69%	2/20/2004	4.97%
10/14/1993	5.852	5.85%	6.70%	2/23/2004	4.97%
10/13/1993	5.917	5.92%	6.70%	2/24/2004	4.97%
10/12/1993	5.92	5.92%	6.71%	2/25/2004	4.98%
10/8/1993	5.923	5.92%	6.72%	2/26/2004	4.98%
10/7/1993	6.012	6.01%	6.73%	2/27/2004	4.98%
10/6/1993	6.008	6.01%	6.73%	3/1/2004	4.98%
10/5/1993	6.008	6.01%	6.74%	3/2/2004	4.99%
10/4/1993	6.002	6.00%	6.75%	3/3/2004	4.99%
10/1/1993	5.99	5.99%	6.75%	3/4/2004	4.99%
9/30/1993	6.025	6.03%	6.76%	3/5/2004	4.99%
9/29/1993	5.998	6.00%	6.77%	3/8/2004	5.00%
9/28/1993	5.941	5.94%	6.77%	3/9/2004	5.00%
9/27/1993	5.949	5.95%	6.78%	3/10/2004	5.00%
9/24/1993	6.048	6.05%	6.79%	3/11/2004	5.00%
9/23/1993	6.064	6.06%	6.79%	3/12/2004	5.00%
9/22/1993	6.087	6.09%	6.80%	3/15/2004	5.00%
9/21/1993	6.124	6.12%	6.81%	3/16/2004	5.01%
9/20/1993	6.095	6.10%	6.81%	3/17/2004	5.01%
9/17/1993	6.038	6.04%	6.82%	3/18/2004	5.01%
9/16/1993	6.032	6.03%	6.83%	3/19/2004	5.01%
9/15/1993	5.982	5.98%	6.84%	3/22/2004	5.01%
9/14/1993	5.975	5.98%	6.84%	3/23/2004	5.02%
9/13/1993	5.875	5.88%	6.85%	3/24/2004	5.02%

9/10/1993	5.881	5.88%	6.86%	3/25/2004	5.02%
9/9/1993	5.958	5.96%	6.87%	3/26/2004	5.02%
9/8/1993	5.865	5.87%	6.87%	3/29/2004	5.02%
9/7/1993	5.902	5.90%	6.88%	3/30/2004	5.03%
9/6/1993	5.944	5.94%	6.89%	3/31/2004	5.03%
9/3/1993	5.944	5.94%	6.90%	4/1/2004	5.03%
9/2/1993	6.042	6.04%	6.91%	4/2/2004	5.03%
9/1/1993	6.086	6.09%	6.92%	4/5/2004	5.03%
8/31/1993	6.092	6.09%	6.92%	4/6/2004	5.03%
8/30/1993	6.118	6.12%	6.93%	4/7/2004	5.04%
8/27/1993	6.134	6.13%	6.94%	4/8/2004	5.04%
8/26/1993	6.095	6.10%	6.94%	4/9/2004	5.04%
8/25/1993	6.17	6.17%	6.95%	4/12/2004	5.04%
8/24/1993	6.199	6.20%	6.96%	4/13/2004	5.04%
8/23/1993	6.221	6.22%	6.96%	4/14/2004	5.05%
8/20/1993	6.217	6.22%	6.97%	4/15/2004	5.05%
8/19/1993	6.195	6.20%	6.98%	4/16/2004	5.05%
8/18/1993	6.258	6.26%	6.99%	4/19/2004	5.05%
8/17/1993	6.31	6.31%	6.99%	4/20/2004	5.06%
8/16/1993	6.303	6.30%	7.00%	4/21/2004	5.06%
8/13/1993	6.348	6.35%	7.01%	4/22/2004	5.06%
8/12/1993	6.438	6.44%	7.01%	4/23/2004	5.06%
8/11/1993	6.43	6.43%	7.02%	4/26/2004	5.06%
8/10/1993	6.447	6.45%	7.03%	4/27/2004	5.06%
8/9/1993	6.469	6.47%	7.03%	4/28/2004	5.06%
8/6/1993	6.526	6.53%	7.04%	4/29/2004	5.06%
8/5/1993	6.524	6.52%	7.04%	4/30/2004	5.06%
8/4/1993	6.551	6.55%	7.05%	5/3/2004	5.06%
8/3/1993	6.526	6.53%	7.05%	5/4/2004	5.06%
8/2/1993	6.552	6.55%	7.06%	5/5/2004	5.07%
7/30/1993	6.564	6.56%	7.06%	5/6/2004	5.07%
7/29/1993	6.567	6.57%	7.07%	5/7/2004	5.07%
7/28/1993	6.654	6.65%	7.08%	5/10/2004	5.07%
7/27/1993	6.675	6.68%	7.08%	5/11/2004	5.07%
7/26/1993	6.677	6.68%	7.08%	5/12/2004	5.07%
7/23/1993	6.699	6.70%	7.09%	5/13/2004	5.07%
7/22/1993	6.659	6.66%	7.09%	5/14/2004	5.07%
7/21/1993	6.624	6.62%	7.10%	5/17/2004	5.07%
7/20/1993	6.552	6.55%	7.10%	5/18/2004	5.07%
7/19/1993	6.539	6.54%	7.11%	5/19/2004	5.07%
7/16/1993	6.539	6.54%	7.11%	5/20/2004	5.07%
7/15/1993	6.56	6.56%	7.12%	5/21/2004	5.07%
7/14/1993	6.561	6.56%	7.12%	5/24/2004	5.07%
7/13/1993	6.612	6.61%	7.13%	5/25/2004	5.08%
7/12/1993	6.624	6.62%	7.13%	5/26/2004	5.08%
7/9/1993	6.637	6.64%	7.13%	5/27/2004	5.08%
7/8/1993	6.656	6.66%	7.14%	5/28/2004	5.08%

7/7/1993	6.677	6.68%	7.14%	5/31/2004	5.08%
7/6/1993	6.678	6.68%	7.14%	6/1/2004	5.08%
7/5/1993	6.665	6.67%	7.15%	6/2/2004	5.08%
7/2/1993	6.663	6.66%	7.15%	6/3/2004	5.08%
7/1/1993	6.682	6.68%	7.15%	6/4/2004	5.08%
6/30/1993	6.672	6.67%	7.16%	6/7/2004	5.08%
6/29/1993	6.67	6.67%	7.16%	6/8/2004	5.08%
6/28/1993	6.669	6.67%	7.16%	6/9/2004	5.08%
6/25/1993	6.7	6.70%	7.17%	6/10/2004	5.08%
6/24/1993	6.733	6.73%	7.17%	6/11/2004	5.08%
6/23/1993	6.76	6.76%	7.17%	6/14/2004	5.09%
6/22/1993	6.771	6.77%	7.18%	6/15/2004	5.09%
6/21/1993	6.772	6.77%	7.18%	6/16/2004	5.09%
6/18/1993	6.806	6.81%	7.18%	6/17/2004	5.09%
6/17/1993	6.806	6.81%	7.18%	6/18/2004	5.09%
6/16/1993	6.813	6.81%	7.19%	6/21/2004	5.09%
6/15/1993	6.82	6.82%	7.19%	6/22/2004	5.09%
6/14/1993	6.814	6.81%	7.19%	6/23/2004	5.09%
6/11/1993	6.803	6.80%	7.19%	6/24/2004	5.09%
6/10/1993	6.872	6.87%	7.20%	6/25/2004	5.10%
6/9/1993	6.881	6.88%	7.20%	6/28/2004	5.10%
6/8/1993	6.918	6.92%	7.20%	6/29/2004	5.10%
6/7/1993	6.878	6.88%	7.20%	6/30/2004	5.10%
6/4/1993	6.908	6.91%	7.21%	7/1/2004	5.10%
6/3/1993	6.857	6.86%	7.21%	7/2/2004	5.10%
6/2/1993	6.875	6.88%	7.21%	7/5/2004	5.10%
6/1/1993	6.881	6.88%	7.22%	7/6/2004	5.11%
5/31/1993	6.98	6.98%	7.22%	7/7/2004	5.11%
5/28/1993	6.978	6.98%	7.22%	7/8/2004	5.11%
5/27/1993	6.932	6.93%	7.22%	7/9/2004	5.11%
5/26/1993	6.92	6.92%	7.22%	7/12/2004	5.11%
5/25/1993	7.005	7.01%	7.23%	7/13/2004	5.11%
5/24/1993	7.004	7.00%	7.23%	7/14/2004	5.11%
5/21/1993	7.031	7.03%	7.23%	7/15/2004	5.11%
5/20/1993	6.993	6.99%	7.23%	7/16/2004	5.11%
5/19/1993	6.969	6.97%	7.23%	7/19/2004	5.11%
5/18/1993	7.018	7.02%	7.23%	7/20/2004	5.11%
5/17/1993	6.964	6.96%	7.24%	7/21/2004	5.11%
5/14/1993	6.945	6.95%	7.24%	7/22/2004	5.11%
5/13/1993	6.953	6.95%	7.24%	7/23/2004	5.11%
5/12/1993	6.856	6.86%	7.24%	7/26/2004	5.11%
5/11/1993	6.812	6.81%	7.25%	7/27/2004	5.11%
5/10/1993	6.809	6.81%	7.25%	7/28/2004	5.11%
5/7/1993	6.844	6.84%	7.25%	7/29/2004	5.11%
5/6/1993	6.803	6.80%	7.26%	7/30/2004	5.11%
5/5/1993	6.784	6.78%	7.26%	8/2/2004	5.11%
5/4/1993	6.788	6.79%	7.26%	8/3/2004	5.11%

5/3/1993	6.861	6.86%	7.27%	8/4/2004	5.11%
4/30/1993	6.933	6.93%	7.27%	8/5/2004	5.11%
4/29/1993	6.879	6.88%	7.27%	8/6/2004	5.11%
4/28/1993	6.919	6.92%	7.28%	8/9/2004	5.11%
4/27/1993	6.899	6.90%	7.28%	8/10/2004	5.11%
4/26/1993	6.826	6.83%	7.28%	8/11/2004	5.11%
4/23/1993	6.79	6.79%	7.29%	8/12/2004	5.11%
4/22/1993	6.748	6.75%	7.29%	8/13/2004	5.11%
4/21/1993	6.744	6.74%	7.30%	8/16/2004	5.11%
4/20/1993	6.749	6.75%	7.30%	8/17/2004	5.10%
4/19/1993	6.722	6.72%	7.31%	8/18/2004	5.10%
4/16/1993	6.755	6.76%	7.31%	8/19/2004	5.10%
4/15/1993	6.721	6.72%	7.31%	8/20/2004	5.10%
4/14/1993	6.755	6.76%	7.32%	8/23/2004	5.10%
4/13/1993	6.78	6.78%	7.32%	8/24/2004	5.10%
4/12/1993	6.792	6.79%	7.33%	8/25/2004	5.10%
4/9/1993	6.847	6.85%	7.33%	8/26/2004	5.10%
4/8/1993	6.849	6.85%	7.34%	8/27/2004	5.10%
4/7/1993	6.951	6.95%	7.34%	8/30/2004	5.10%
4/6/1993	6.964	6.96%	7.35%	8/31/2004	5.10%
4/5/1993	7.025	7.03%	7.35%	9/1/2004	5.10%
4/2/1993	7.054	7.05%	7.35%	9/2/2004	5.10%
4/1/1993	6.966	6.97%	7.36%	9/3/2004	5.10%
3/31/1993	6.926	6.93%	7.36%	9/6/2004	5.10%
3/30/1993	6.909	6.91%	7.37%	9/7/2004	5.10%
3/29/1993	6.889	6.89%	7.37%	9/8/2004	5.10%
3/26/1993	6.938	6.94%	7.37%	9/9/2004	5.10%
3/25/1993	6.851	6.85%	7.38%	9/10/2004	5.10%
3/24/1993	6.815	6.82%	7.38%	9/13/2004	5.10%
3/23/1993	6.769	6.77%	7.39%	9/14/2004	5.09%
3/22/1993	6.797	6.80%	7.39%	9/15/2004	5.09%
3/19/1993	6.802	6.80%	7.40%	9/16/2004	5.09%
3/18/1993	6.781	6.78%	7.41%	9/17/2004	5.09%
3/17/1993	6.864	6.86%	7.41%	9/20/2004	5.09%
3/16/1993	6.874	6.87%	7.42%	9/21/2004	5.09%
3/15/1993	6.892	6.89%	7.42%	9/22/2004	5.09%
3/12/1993	6.858	6.86%	7.43%	9/23/2004	5.09%
3/11/1993	6.763	6.76%	7.43%	9/24/2004	5.09%
3/10/1993	6.747	6.75%	7.44%	9/27/2004	5.09%
3/9/1993	6.736	6.74%	7.44%	9/28/2004	5.08%
3/8/1993	6.721	6.72%	7.45%	9/29/2004	5.08%
3/5/1993	6.737	6.74%	7.45%	9/30/2004	5.08%
3/4/1993	6.724	6.72%	7.46%	10/1/2004	5.08%
3/3/1993	6.781	6.78%	7.47%	10/4/2004	5.08%
3/2/1993	6.837	6.84%	7.47%	10/5/2004	5.08%
3/1/1993	6.841	6.84%	7.48%	10/6/2004	5.08%
2/26/1993	6.897	6.90%	7.48%	10/7/2004	5.08%

2/25/1993	6.89	6.89%	7.48%	10/8/2004	5.08%
2/24/1993	6.885	6.89%	7.49%	10/11/2004	5.08%
2/23/1993	6.822	6.82%	7.49%	10/12/2004	5.08%
2/22/1993	6.935	6.94%	7.50%	10/13/2004	5.08%
2/19/1993	7.006	7.01%	7.50%	10/14/2004	5.07%
2/18/1993	7.019	7.02%	7.51%	10/15/2004	5.07%
2/17/1993	7.1	7.10%	7.51%	10/18/2004	5.07%
2/16/1993	7.149	7.15%	7.52%	10/19/2004	5.07%
2/15/1993	7.109	7.11%	7.52%	10/20/2004	5.07%
2/12/1993	7.124	7.12%	7.52%	10/21/2004	5.07%
2/11/1993	7.199	7.20%	7.53%	10/22/2004	5.07%
2/10/1993	7.251	7.25%	7.53%	10/25/2004	5.07%
2/9/1993	7.199	7.20%	7.54%	10/26/2004	5.07%
2/8/1993	7.197	7.20%	7.54%	10/27/2004	5.07%
2/5/1993	7.161	7.16%	7.55%	10/28/2004	5.07%
2/4/1993	7.184	7.18%	7.55%	10/29/2004	5.07%
2/3/1993	7.213	7.21%	7.55%	11/1/2004	5.07%
2/2/1993	7.245	7.25%	7.56%	11/2/2004	5.07%
2/1/1993	7.207	7.21%	7.56%	11/3/2004	5.07%
1/29/1993	7.197	7.20%	7.57%	11/4/2004	5.07%
1/28/1993	7.204	7.20%	7.57%	11/5/2004	5.07%
1/27/1993	7.244	7.24%	7.58%	11/8/2004	5.07%
1/26/1993	7.255	7.26%	7.58%	11/9/2004	5.07%
1/25/1993	7.203	7.20%	7.58%	11/10/2004	5.07%
1/22/1993	7.29	7.29%	7.59%	11/11/2004	5.07%
1/21/1993	7.302	7.30%	7.59%	11/12/2004	5.06%
1/20/1993	7.329	7.33%	7.59%	11/15/2004	5.06%
1/19/1993	7.299	7.30%	7.59%	11/16/2004	5.06%
1/18/1993	7.346	7.35%	7.60%	11/17/2004	5.06%
1/15/1993	7.346	7.35%	7.60%	11/18/2004	5.06%
1/14/1993	7.393	7.39%	7.60%	11/19/2004	5.06%
1/13/1993	7.432	7.43%	7.60%	11/22/2004	5.06%
1/12/1993	7.476	7.48%	7.61%	11/23/2004	5.06%
1/11/1993	7.449	7.45%	7.61%	11/24/2004	5.06%
1/8/1993	7.465	7.47%	7.61%	11/25/2004	5.06%
1/7/1993	7.445	7.45%	7.61%	11/26/2004	5.06%
1/6/1993	7.35	7.35%	7.62%	11/29/2004	5.06%
1/5/1993	7.32	7.32%	7.62%	11/30/2004	5.06%
1/4/1993	7.32	7.32%	7.62%	12/1/2004	5.06%
12/31/1992	7.396	7.40%	7.63%	12/2/2004	5.06%
12/30/1992	7.381	7.38%	7.63%	12/3/2004	5.06%
12/29/1992	7.361	7.36%	7.63%	12/6/2004	5.06%
12/28/1992	7.399	7.40%	7.64%	12/7/2004	5.06%
12/25/1992	7.361	7.36%	7.64%	12/8/2004	5.06%
12/24/1992	7.36	7.36%	7.64%	12/9/2004	5.06%
12/23/1992	7.355	7.36%	7.64%	12/10/2004	5.06%
12/22/1992	7.339	7.34%	7.65%	12/13/2004	5.06%

12/21/1992	7.389	7.39%	7.65%	12/14/2004	5.07%
12/18/1992	7.425	7.43%	7.65%	12/15/2004	5.07%
12/17/1992	7.422	7.42%	7.66%	12/16/2004	5.07%
12/16/1992	7.432	7.43%	7.66%	12/17/2004	5.07%
12/15/1992	7.448	7.45%	7.66%	12/20/2004	5.07%
12/14/1992	7.462	7.46%	7.66%	12/21/2004	5.07%
12/11/1992	7.438	7.44%	7.67%	12/22/2004	5.07%
12/10/1992	7.425	7.43%	7.67%	12/23/2004	5.07%
12/9/1992	7.437	7.44%	7.67%	12/24/2004	5.07%
12/8/1992	7.433	7.43%	7.67%	12/27/2004	5.07%
12/7/1992	7.455	7.46%	7.68%	12/28/2004	5.07%
12/4/1992	7.487	7.49%	7.68%	12/29/2004	5.07%
12/3/1992	7.559	7.56%	7.68%	12/30/2004	5.08%
12/2/1992	7.564	7.56%	7.68%	12/31/2004	5.08%
12/1/1992	7.567	7.57%	7.68%	1/3/2005	5.08%
11/30/1992	7.597	7.60%	7.69%	1/4/2005	5.08%
11/27/1992	7.591	7.59%	7.69%	1/5/2005	5.08%
11/26/1992	7.529	7.53%	7.69%	1/6/2005	5.08%
11/25/1992	7.542	7.54%	7.69%	1/7/2005	5.08%
11/24/1992	7.533	7.53%	7.69%	1/10/2005	5.07%
11/23/1992	7.543	7.54%	7.70%	1/11/2005	5.07%
11/20/1992	7.534	7.53%	7.70%	1/12/2005	5.07%
11/19/1992	7.545	7.55%	7.70%	1/13/2005	5.07%
11/18/1992	7.504	7.50%	7.70%	1/14/2005	5.07%
11/17/1992	7.538	7.54%	7.70%	1/17/2005	5.07%
11/16/1992	7.566	7.57%	7.70%	1/18/2005	5.07%
11/13/1992	7.565	7.57%	7.70%	1/19/2005	5.06%
11/12/1992	7.597	7.60%	7.70%	1/20/2005	5.06%
11/11/1992	7.661	7.66%	7.70%	1/21/2005	5.06%
11/10/1992	7.667	7.67%	7.71%	1/24/2005	5.05%
11/9/1992	7.739	7.74%	7.71%	1/25/2005	5.05%
11/6/1992	7.756	7.76%	7.71%	1/26/2005	5.05%
11/5/1992	7.688	7.69%	7.71%	1/27/2005	5.05%
11/4/1992	7.68	7.68%	7.71%	1/28/2005	5.04%
11/3/1992	7.652	7.65%	7.71%	1/31/2005	5.04%
11/2/1992	7.66	7.66%	7.71%	2/1/2005	5.04%
10/30/1992	7.626	7.63%	7.71%	2/2/2005	5.03%
10/29/1992	7.58	7.58%	7.71%	2/3/2005	5.03%
10/28/1992	7.612	7.61%	7.71%	2/4/2005	5.03%
10/27/1992	7.619	7.62%	7.71%	2/7/2005	5.02%
10/26/1992	7.66	7.66%	7.71%	2/8/2005	5.02%
10/23/1992	7.645	7.65%	7.71%	2/9/2005	5.01%
10/22/1992	7.62	7.62%	7.71%	2/10/2005	5.01%
10/21/1992	7.604	7.60%	7.71%	2/11/2005	5.00%
10/20/1992	7.649	7.65%	7.71%	2/14/2005	5.00%
10/19/1992	7.566	7.57%	7.70%	2/15/2005	4.99%
10/16/1992	7.531	7.53%	7.70%	2/16/2005	4.99%

10/15/1992	7.508	7.51%	7.70%	2/17/2005	4.98%
10/14/1992	7.499	7.50%	7.70%	2/18/2005	4.98%
10/13/1992	7.534	7.53%	7.70%	2/21/2005	4.97%
10/12/1992	7.511	7.51%	7.70%	2/22/2005	4.97%
10/9/1992	7.524	7.52%	7.70%	2/23/2005	4.97%
10/8/1992	7.445	7.45%	7.70%	2/24/2005	4.96%
10/7/1992	7.484	7.48%	7.70%	2/25/2005	4.96%
10/6/1992	7.414	7.41%	7.70%	2/28/2005	4.95%
10/5/1992	7.35	7.35%	7.70%	3/1/2005	4.95%
10/2/1992	7.334	7.33%	7.70%	3/2/2005	4.95%
10/1/1992	7.322	7.32%	7.70%	3/3/2005	4.94%
9/30/1992	7.381	7.38%	7.70%	3/4/2005	4.94%
9/29/1992	7.363	7.36%	7.71%	3/7/2005	4.94%
9/28/1992	7.341	7.34%	7.71%	3/8/2005	4.93%
9/25/1992	7.359	7.36%	7.71%	3/9/2005	4.93%
9/24/1992	7.42	7.42%	7.71%	3/10/2005	4.93%
9/23/1992	7.487	7.49%	7.71%	3/11/2005	4.92%
9/22/1992	7.466	7.47%	7.71%	3/14/2005	4.92%
9/21/1992	7.354	7.35%	7.72%	3/15/2005	4.92%
9/18/1992	7.322	7.32%	7.72%	3/16/2005	4.92%
9/17/1992	7.329	7.33%	7.72%	3/17/2005	4.91%
9/16/1992	7.332	7.33%	7.72%	3/18/2005	4.91%
9/15/1992	7.315	7.32%	7.72%	3/21/2005	4.90%
9/14/1992	7.259	7.26%	7.73%	3/22/2005	4.90%
9/11/1992	7.293	7.29%	7.73%	3/23/2005	4.90%
9/10/1992	7.245	7.25%	7.73%	3/24/2005	4.90%
9/9/1992	7.255	7.26%	7.74%	3/25/2005	4.89%
9/8/1992	7.224	7.22%	7.74%	3/28/2005	4.89%
9/4/1992	7.28	7.28%	7.74%	3/29/2005	4.89%
9/3/1992	7.357	7.36%	7.75%	3/30/2005	4.89%
9/2/1992	7.372	7.37%	7.75%	3/31/2005	4.88%
9/1/1992	7.376	7.38%	7.75%	4/1/2005	4.88%
8/31/1992	7.409	7.41%	7.76%	4/4/2005	4.88%
8/28/1992	7.423	7.42%	7.76%	4/5/2005	4.87%
8/27/1992	7.408	7.41%	7.76%	4/6/2005	4.87%
8/26/1992	7.419	7.42%	7.76%	4/7/2005	4.87%
8/25/1992	7.476	7.48%	7.77%	4/8/2005	4.87%
8/24/1992	7.446	7.45%	7.77%	4/11/2005	4.86%
8/21/1992	7.35	7.35%	7.77%	4/12/2005	4.86%
8/20/1992	7.314	7.31%	7.77%	4/13/2005	4.86%
8/19/1992	7.315	7.32%	7.77%	4/14/2005	4.86%
8/18/1992	7.333	7.33%	7.78%	4/15/2005	4.85%
8/17/1992	7.356	7.36%	7.78%	4/18/2005	4.85%
8/14/1992	7.324	7.32%	7.78%	4/19/2005	4.85%
8/13/1992	7.417	7.42%	7.79%	4/20/2005	4.84%
8/12/1992	7.327	7.33%	7.79%	4/21/2005	4.84%
8/11/1992	7.318	7.32%	7.79%	4/22/2005	4.84%

8/10/1992	7.364	7.36%	7.80%	4/25/2005	4.83%
8/7/1992	7.396	7.40%	7.80%	4/26/2005	4.83%
8/6/1992	7.459	7.46%	7.80%	4/27/2005	4.83%
8/5/1992	7.426	7.43%	7.80%	4/28/2005	4.83%
8/4/1992	7.426	7.43%	7.81%	4/29/2005	4.82%
8/3/1992	7.452	7.45%	7.81%	5/2/2005	4.82%
7/31/1992	7.458	7.46%	7.81%	5/3/2005	4.81%
7/30/1992	7.439	7.44%	7.82%	5/4/2005	4.81%
7/29/1992	7.439	7.44%	7.82%	5/5/2005	4.81%
7/28/1992	7.433	7.43%	7.82%	5/6/2005	4.80%
7/27/1992	7.519	7.52%	7.82%	5/9/2005	4.80%
7/24/1992	7.572	7.57%	7.83%	5/10/2005	4.80%
7/23/1992	7.537	7.54%	7.83%	5/11/2005	4.80%
7/22/1992	7.616	7.62%	7.83%	5/12/2005	4.79%
7/21/1992	7.66	7.66%	7.83%	5/13/2005	4.79%
7/20/1992	7.661	7.66%	7.83%	5/16/2005	4.79%
7/17/1992	7.678	7.68%	7.83%	5/17/2005	4.78%
7/16/1992	7.61	7.61%	7.84%	5/18/2005	4.78%
7/15/1992	7.624	7.62%	7.84%	5/19/2005	4.78%
7/14/1992	7.684	7.68%	7.84%	5/20/2005	4.77%
7/13/1992	7.677	7.68%	7.84%	5/23/2005	4.77%
7/10/1992	7.633	7.63%	7.84%	5/24/2005	4.77%
7/9/1992	7.596	7.60%	7.84%	5/25/2005	4.76%
7/8/1992	7.607	7.61%	7.84%	5/26/2005	4.76%
7/7/1992	7.601	7.60%	7.84%	5/27/2005	4.76%
7/6/1992	7.623	7.62%	7.84%	5/30/2005	4.76%
7/3/1992	7.629	7.63%	7.84%	5/31/2005	4.75%
7/2/1992	7.628	7.63%	7.85%	6/1/2005	4.75%
7/1/1992	7.742	7.74%	7.85%	6/2/2005	4.74%
6/30/1992	7.78	7.78%	7.85%	6/3/2005	4.74%
6/29/1992	7.766	7.77%	7.85%	6/6/2005	4.74%
6/26/1992	7.782	7.78%	7.85%	6/7/2005	4.73%
6/25/1992	7.773	7.77%	7.85%	6/8/2005	4.73%
6/24/1992	7.825	7.83%	7.85%	6/9/2005	4.73%
6/23/1992	7.844	7.84%	7.85%	6/10/2005	4.72%
6/22/1992	7.838	7.84%	7.85%	6/13/2005	4.72%
6/19/1992	7.83	7.83%	7.85%	6/14/2005	4.72%
6/18/1992	7.801	7.80%	7.85%	6/15/2005	4.71%
6/17/1992	7.82	7.82%	7.85%	6/16/2005	4.71%
6/16/1992	7.832	7.83%	7.85%	6/17/2005	4.71%
6/15/1992	7.851	7.85%	7.85%	6/20/2005	4.70%
6/12/1992	7.858	7.86%	7.86%	6/21/2005	4.70%
6/11/1992	7.876	7.88%	7.86%	6/22/2005	4.70%
6/10/1992	7.899	7.90%	7.86%	6/23/2005	4.69%
6/9/1992	7.878	7.88%	7.86%	6/24/2005	4.69%
6/8/1992	7.84	7.84%	7.86%	6/27/2005	4.69%
6/5/1992	7.847	7.85%	7.86%	6/28/2005	4.68%

6/4/1992	7.878	7.88%	7.86%	6/29/2005	4.68%
6/3/1992	7.872	7.87%	7.86%	6/30/2005	4.68%
6/2/1992	7.86	7.86%	7.86%	7/1/2005	4.68%
6/1/1992	7.889	7.89%	7.87%	7/4/2005	4.67%
5/29/1992	7.837	7.84%	7.87%	7/5/2005	4.67%
5/28/1992	7.859	7.86%	7.87%	7/6/2005	4.67%
5/27/1992	7.903	7.90%	7.87%	7/7/2005	4.67%
5/26/1992	7.914	7.91%	7.87%	7/8/2005	4.66%
5/25/1992	7.811	7.81%	7.87%	7/11/2005	4.66%
5/22/1992	7.822	7.82%	7.87%	7/12/2005	4.66%
5/21/1992	7.865	7.87%	7.87%	7/13/2005	4.65%
5/20/1992	7.811	7.81%	7.87%	7/14/2005	4.65%
5/19/1992	7.768	7.77%	7.88%	7/15/2005	4.65%
5/18/1992	7.819	7.82%	7.88%	7/18/2005	4.65%
5/15/1992	7.819	7.82%	7.88%	7/19/2005	4.64%
5/14/1992	7.868	7.87%	7.88%	7/20/2005	4.64%
5/12/1992	7.862	7.86%	7.88%	7/21/2005	4.64%
5/11/1992	7.888	7.89%	7.89%	7/22/2005	4.64%
5/8/1992	7.895	7.90%	7.89%	7/25/2005	4.64%
5/7/1992	7.973	7.97%	7.89%	7/26/2005	4.64%
5/6/1992	7.963	7.96%	7.89%	7/27/2005	4.63%
5/5/1992	7.999	8.00%	7.89%	7/28/2005	4.63%
5/4/1992	8.027	8.03%	7.90%	7/29/2005	4.63%
5/1/1992	8.013	8.01%	7.90%	8/1/2005	4.63%
4/30/1992	8.036	8.04%	7.90%	8/2/2005	4.63%
4/29/1992	8.063	8.06%	7.90%	8/3/2005	4.63%
4/28/1992	8.049	8.05%	7.90%	8/4/2005	4.62%
4/27/1992	8.105	8.11%	7.91%	8/5/2005	4.62%
4/24/1992	8.042	8.04%	7.91%	8/8/2005	4.62%
4/23/1992	8.053	8.05%	7.91%	8/9/2005	4.62%
4/22/1992	8.037	8.04%	7.91%	8/10/2005	4.62%
4/21/1992	8.022	8.02%	7.91%	8/11/2005	4.62%
4/20/1992	8.029	8.03%	7.92%	8/12/2005	4.62%
4/17/1992	7.938	7.94%	7.92%	8/15/2005	4.61%
4/16/1992	7.932	7.93%	7.92%	8/16/2005	4.61%
4/15/1992	7.872	7.87%	7.92%	8/17/2005	4.61%
4/14/1992	7.868	7.87%	7.93%	8/18/2005	4.61%
4/13/1992	7.859	7.86%	7.93%	8/19/2005	4.60%
4/10/1992	7.886	7.89%	7.93%	8/22/2005	4.60%
4/9/1992	7.864	7.86%	7.94%	8/23/2005	4.60%
4/8/1992	7.914	7.91%	7.94%	8/24/2005	4.60%
4/7/1992	7.886	7.89%	7.94%	8/25/2005	4.59%
4/6/1992	7.895	7.90%	7.94%	8/26/2005	4.59%
4/3/1992	7.876	7.88%	7.95%	8/29/2005	4.59%
4/2/1992	7.903	7.90%	7.95%	8/30/2005	4.59%
4/1/1992	7.896	7.90%	7.95%	8/31/2005	4.58%
3/31/1992	7.958	7.96%	7.96%	9/1/2005	4.58%

3/30/1992	7.94	7.94%	7.96%	9/2/2005	4.58%
3/27/1992	7.94	7.94%	7.96%	9/5/2005	4.58%
3/26/1992	7.999	8.00%	7.96%	9/6/2005	4.57%
3/25/1992	7.944	7.94%	7.97%	9/7/2005	4.57%
3/24/1992	7.945	7.95%	7.97%	9/8/2005	4.57%
3/23/1992	8.031	8.03%	7.97%	9/9/2005	4.56%
3/20/1992	8.046	8.05%	7.97%	9/12/2005	4.56%
3/19/1992	7.969	7.97%	7.98%	9/13/2005	4.56%
3/18/1992	8.01	8.01%	7.98%	9/14/2005	4.56%
3/17/1992	8.007	8.01%	7.98%	9/15/2005	4.56%
3/16/1992	8.069	8.07%	7.98%	9/16/2005	4.55%
3/13/1992	8.066	8.07%	7.99%	9/19/2005	4.55%
3/12/1992	8.035	8.04%	7.99%	9/20/2005	4.55%
3/11/1992	7.959	7.96%	7.99%	9/21/2005	4.55%
3/10/1992	7.902	7.90%	7.99%	9/22/2005	4.55%
3/9/1992	7.872	7.87%	7.99%	9/23/2005	4.55%
3/6/1992	7.932	7.93%	8.00%	9/26/2005	4.55%
3/5/1992	7.963	7.96%	8.00%	9/27/2005	4.54%
3/4/1992	7.908	7.91%	8.00%	9/28/2005	4.54%
3/3/1992	7.919	7.92%	8.00%	9/29/2005	4.54%
3/2/1992	7.898	7.90%	8.00%	9/30/2005	4.54%
2/28/1992	7.789	7.79%	8.00%	10/3/2005	4.54%
2/27/1992	7.849	7.85%	8.01%	10/4/2005	4.54%
2/26/1992	7.846	7.85%	8.01%	10/5/2005	4.53%
2/25/1992	7.948	7.95%	8.01%	10/6/2005	4.53%
2/24/1992	7.967	7.97%	8.01%	10/7/2005	4.53%
2/21/1992	7.945	7.95%	8.01%	10/10/2005	4.53%
2/20/1992	7.91	7.91%	8.02%	10/11/2005	4.53%
2/19/1992	7.912	7.91%	8.02%	10/12/2005	4.53%
2/18/1992	7.98	7.98%	8.02%	10/13/2005	4.53%
2/17/1992	7.982	7.98%	8.02%	10/14/2005	4.53%
2/14/1992	7.906	7.91%	8.02%	10/17/2005	4.53%
2/13/1992	7.912	7.91%	8.03%	10/18/2005	4.53%
2/12/1992	7.813	7.81%	8.03%	10/19/2005	4.53%
2/11/1992	7.786	7.79%	8.03%	10/20/2005	4.53%
2/10/1992	7.787	7.79%	8.03%	10/21/2005	4.53%
2/7/1992	7.76	7.76%	8.03%	10/24/2005	4.52%
2/6/1992	7.768	7.77%	8.04%	10/25/2005	4.53%
2/5/1992	7.731	7.73%	8.04%	10/26/2005	4.53%
2/4/1992	7.744	7.74%	8.04%	10/27/2005	4.53%
2/3/1992	7.818	7.82%	8.04%	10/28/2005	4.53%
1/31/1992	7.758	7.76%	8.04%	10/31/2005	4.53%
1/30/1992	7.788	7.79%	8.05%	11/1/2005	4.53%
1/29/1992	7.752	7.75%	8.05%	11/2/2005	4.53%
1/28/1992	7.667	7.67%	8.05%	11/3/2005	4.53%
1/27/1992	7.718	7.72%	8.05%	11/4/2005	4.53%
1/24/1992	7.708	7.71%	8.06%	11/7/2005	4.53%

1/23/1992	7.724	7.72%	8.06%	11/8/2005	4.53%
1/22/1992	7.627	7.63%	8.06%	11/9/2005	4.53%
1/21/1992	7.573	7.57%	8.06%	11/10/2005	4.53%
1/20/1992	7.592	7.59%	8.07%	11/11/2005	4.54%
1/17/1992	7.614	7.61%	8.07%	11/14/2005	4.54%
1/16/1992	7.67	7.67%	8.07%	11/15/2005	4.54%
1/15/1992	7.576	7.58%	8.08%	11/16/2005	4.54%
1/14/1992	7.54	7.54%	8.08%	11/17/2005	4.54%
1/13/1992	7.522	7.52%	8.08%	11/18/2005	4.54%
1/10/1992	7.462	7.46%	8.09%	11/21/2005	4.54%
1/9/1992	7.412	7.41%	8.09%	11/22/2005	4.55%
1/8/1992	7.388	7.39%	8.09%	11/23/2005	4.55%
1/7/1992	7.397	7.40%	8.10%	11/24/2005	4.55%
1/6/1992	7.434	7.43%	8.10%	11/25/2005	4.55%
1/3/1992	7.48	7.48%	8.11%	11/28/2005	4.55%
1/2/1992	7.465	7.47%	8.11%	11/29/2005	4.55%
12/31/1991	7.401	7.40%	8.11%	11/30/2005	4.55%
12/30/1991	7.44	7.44%	8.12%	12/1/2005	4.55%
12/27/1991	7.513	7.51%	8.12%	12/2/2005	4.55%
12/26/1991	7.508	7.51%	8.13%	12/5/2005	4.55%
12/25/1991	7.524	7.52%	8.13%	12/6/2005	4.55%
12/24/1991	7.523	7.52%	8.13%	12/7/2005	4.55%
12/23/1991	7.527	7.53%	8.14%	12/8/2005	4.55%
12/20/1991	7.589	7.59%	8.14%	12/9/2005	4.55%
12/19/1991	7.655	7.66%	8.15%	12/12/2005	4.55%
12/18/1991	7.758	7.76%	8.15%	12/13/2005	4.55%
12/17/1991	7.753	7.75%	8.15%	12/14/2005	4.55%
12/16/1991	7.753	7.75%	8.15%	12/15/2005	4.55%
12/13/1991	7.774	7.77%	8.16%	12/16/2005	4.55%
12/12/1991	7.753	7.75%	8.16%	12/19/2005	4.55%
12/11/1991	7.807	7.81%	8.16%	12/20/2005	4.54%
12/10/1991	7.787	7.79%	8.16%	12/21/2005	4.54%
12/9/1991	7.789	7.79%	8.17%	12/22/2005	4.54%
12/6/1991	7.806	7.81%	8.17%	12/23/2005	4.54%
12/5/1991	7.841	7.84%	8.17%	12/27/2005	4.54%
12/4/1991	7.849	7.85%	8.17%	12/28/2005	4.54%
12/3/1991	7.901	7.90%	8.17%	12/29/2005	4.54%
12/2/1991	7.906	7.91%	8.17%	12/30/2005	4.53%
11/29/1991	7.942	7.94%	8.18%	1/2/2006	4.53%
11/28/1991	7.968	7.97%	8.18%	1/3/2006	4.53%
11/27/1991	7.966	7.97%	8.18%	1/4/2006	4.53%
11/26/1991	7.948	7.95%	8.18%	1/5/2006	4.53%
11/25/1991	7.986	7.99%	8.18%	1/6/2006	4.53%
11/22/1991	7.981	7.98%	8.18%	1/9/2006	4.53%
11/21/1991	7.976	7.98%	8.18%	1/10/2006	4.53%
11/20/1991	7.902	7.90%	8.18%	1/11/2006	4.53%
11/19/1991	7.922	7.92%	8.18%	1/12/2006	4.53%

11/18/1991	7.848	7.85%	8.18%	1/13/2006	4.52%
11/15/1991	7.821	7.82%	8.18%	1/16/2006	4.52%
11/14/1991	7.817	7.82%	8.18%	1/17/2006	4.52%
11/13/1991	7.862	7.86%	8.18%	1/18/2006	4.52%
11/12/1991	7.788	7.79%	8.18%	1/19/2006	4.52%
11/11/1991	7.866	7.87%	8.18%	1/20/2006	4.52%
11/8/1991	7.872	7.87%	8.18%	1/23/2006	4.52%
11/7/1991	7.922	7.92%	8.18%	1/24/2006	4.52%
11/6/1991	7.998	8.00%	8.19%	1/25/2006	4.52%
11/5/1991	8.025	8.03%	8.19%	1/26/2006	4.52%
11/4/1991	7.952	7.95%	8.19%	1/27/2006	4.52%
11/1/1991	7.93	7.93%	8.19%	1/30/2006	4.52%
10/31/1991	7.914	7.91%	8.19%	1/31/2006	4.52%
10/30/1991	7.901	7.90%	8.19%	2/1/2006	4.52%
10/29/1991	7.894	7.89%	8.19%	2/2/2006	4.52%
10/28/1991	8.028	8.03%	8.19%	2/3/2006	4.52%
10/25/1991	8.046	8.05%	8.20%	2/6/2006	4.52%
10/24/1991	8.032	8.03%	8.20%	2/7/2006	4.52%
10/23/1991	8.075	8.08%	8.20%	2/8/2006	4.53%
10/22/1991	8.1	8.10%	8.20%	2/9/2006	4.53%
10/21/1991	8.071	8.07%	8.20%	2/10/2006	4.53%
10/18/1991	7.955	7.96%	8.20%	2/13/2006	4.53%
10/17/1991	8.023	8.02%	8.20%	2/14/2006	4.53%
10/16/1991	7.881	7.88%	8.20%	2/15/2006	4.53%
10/15/1991	7.857	7.86%	8.21%	2/16/2006	4.53%
10/14/1991	7.873	7.87%	8.21%	2/17/2006	4.53%
10/11/1991	7.867	7.87%	8.21%	2/20/2006	4.53%
10/10/1991	7.964	7.96%	8.21%	2/21/2006	4.53%
10/9/1991	7.912	7.91%	8.22%	2/22/2006	4.53%
10/8/1991	7.824	7.82%	8.22%	2/23/2006	4.53%
10/7/1991	7.791	7.79%	8.22%	2/24/2006	4.53%
10/4/1991	7.783	7.78%	8.22%	2/27/2006	4.53%
10/3/1991	7.841	7.84%	8.22%	2/28/2006	4.53%
10/2/1991	7.828	7.83%	8.23%	3/1/2006	4.53%
10/1/1991	7.799	7.80%	8.23%	3/2/2006	4.53%
9/30/1991	7.809	7.81%	8.23%	3/3/2006	4.53%
9/27/1991	7.821	7.82%	8.23%	3/6/2006	4.53%
9/26/1991	7.88	7.88%	8.24%	3/7/2006	4.53%
9/25/1991	7.903	7.90%	8.24%	3/8/2006	4.54%
9/24/1991	7.882	7.88%	8.24%	3/9/2006	4.54%
9/23/1991	7.873	7.87%	8.24%	3/10/2006	4.54%
9/20/1991	7.892	7.89%	8.24%	3/13/2006	4.54%
9/19/1991	7.913	7.91%	8.24%	3/14/2006	4.55%
9/18/1991	7.919	7.92%	8.24%	3/15/2006	4.55%
9/17/1991	7.911	7.91%	8.24%	3/16/2006	4.55%
9/16/1991	7.93	7.93%	8.24%	3/17/2006	4.55%
9/13/1991	7.94	7.94%	8.25%	3/20/2006	4.55%

9/12/1991	7.923	7.92%	8.25%	3/21/2006	4.56%
9/11/1991	8.017	8.02%	8.25%	3/22/2006	4.56%
9/10/1991	8.006	8.01%	8.25%	3/23/2006	4.56%
9/9/1991	7.994	7.99%	8.25%	3/24/2006	4.56%
9/6/1991	8.015	8.02%	8.26%	3/27/2006	4.56%
9/5/1991	8.094	8.09%	8.26%	3/28/2006	4.57%
9/4/1991	8.06	8.06%	8.26%	3/29/2006	4.57%
9/3/1991	8.042	8.04%	8.26%	3/30/2006	4.57%
9/2/1991	8.051	8.05%	8.27%	3/31/2006	4.57%
8/30/1991	8.06	8.06%	8.27%	4/3/2006	4.58%
8/29/1991	8.005	8.01%	8.27%	4/4/2006	4.58%
8/28/1991	8.061	8.06%	8.27%	4/5/2006	4.58%
8/27/1991	8.152	8.15%	8.27%	4/6/2006	4.59%
8/26/1991	8.152	8.15%	8.27%	4/7/2006	4.59%
8/23/1991	8.125	8.13%	8.28%	4/10/2006	4.60%
8/22/1991	8.049	8.05%	8.28%	4/11/2006	4.60%
8/21/1991	8.061	8.06%	8.28%	4/12/2006	4.60%
8/20/1991	8.088	8.09%	8.28%	4/13/2006	4.61%
8/19/1991	8.111	8.11%	8.29%	4/14/2006	4.61%
8/16/1991	8.088	8.09%	8.29%	4/17/2006	4.61%
8/15/1991	8.088	8.09%	8.29%	4/18/2006	4.62%
8/14/1991	8.062	8.06%	8.29%	4/19/2006	4.62%
8/13/1991	8.169	8.17%	8.30%	4/20/2006	4.63%
8/12/1991	8.212	8.21%	8.30%	4/21/2006	4.63%
8/9/1991	8.22	8.22%	8.30%	4/24/2006	4.63%
8/8/1991	8.227	8.23%	8.31%	4/25/2006	4.64%
8/7/1991	8.18	8.18%	8.31%	4/26/2006	4.64%
8/6/1991	8.176	8.18%	8.31%	4/27/2006	4.64%
8/5/1991	8.226	8.23%	8.31%	4/28/2006	4.65%
8/2/1991	8.244	8.24%	8.32%	5/1/2006	4.65%
8/1/1991	8.358	8.36%	8.32%	5/2/2006	4.65%
7/31/1991	8.341	8.34%	8.32%	5/3/2006	4.66%
7/30/1991	8.379	8.38%	8.32%	5/4/2006	4.66%
7/29/1991	8.395	8.40%	8.33%	5/5/2006	4.67%
7/26/1991	8.388	8.39%	8.33%	5/8/2006	4.67%
7/25/1991	8.379	8.38%	8.33%	5/9/2006	4.67%
7/24/1991	8.416	8.42%	8.33%	5/10/2006	4.68%
7/23/1991	8.491	8.49%	8.34%	5/11/2006	4.68%
7/22/1991	8.469	8.47%	8.34%	5/12/2006	4.68%
7/19/1991	8.474	8.47%	8.34%	5/15/2006	4.69%
7/18/1991	8.474	8.47%	8.34%	5/16/2006	4.69%
7/17/1991	8.501	8.50%	8.35%	5/17/2006	4.69%
7/16/1991	8.453	8.45%	8.35%	5/18/2006	4.70%
7/15/1991	8.457	8.46%	8.35%	5/19/2006	4.70%
7/12/1991	8.442	8.44%	8.35%	5/22/2006	4.70%
7/11/1991	8.466	8.47%	8.35%	5/23/2006	4.71%
7/10/1991	8.513	8.51%	8.36%	5/24/2006	4.71%

7/9/1991	8.531	8.53%	8.36%	5/25/2006	4.71%
7/8/1991	8.499	8.50%	8.36%	5/26/2006	4.72%
7/5/1991	8.495	8.50%	8.36%	5/29/2006	4.72%
7/4/1991	8.425	8.43%	8.36%	5/30/2006	4.73%
7/3/1991	8.414	8.41%	8.37%	5/31/2006	4.73%
7/2/1991	8.437	8.44%	8.37%	6/1/2006	4.73%
7/1/1991	8.434	8.43%	8.38%	6/2/2006	4.74%
6/28/1991	8.406	8.41%	8.38%	6/5/2006	4.74%
6/27/1991	8.484	8.48%	8.38%	6/6/2006	4.74%
6/26/1991	8.514	8.51%	8.38%	6/7/2006	4.75%
6/25/1991	8.511	8.51%	8.39%	6/8/2006	4.75%
6/24/1991	8.508	8.51%	8.39%	6/9/2006	4.76%
6/21/1991	8.51	8.51%	8.39%	6/12/2006	4.76%
6/20/1991	8.465	8.47%	8.39%	6/13/2006	4.76%
6/19/1991	8.507	8.51%	8.40%	6/14/2006	4.77%
6/18/1991	8.517	8.52%	8.40%	6/15/2006	4.77%
6/17/1991	8.498	8.50%	8.40%	6/16/2006	4.77%
6/14/1991	8.47	8.47%	8.40%	6/19/2006	4.78%
6/13/1991	8.514	8.51%	8.41%	6/20/2006	4.78%
6/12/1991	8.548	8.55%	8.41%	6/21/2006	4.79%
6/11/1991	8.476	8.48%	8.41%	6/22/2006	4.79%
6/10/1991	8.477	8.48%	8.41%	6/23/2006	4.79%
6/7/1991	8.476	8.48%	8.42%	6/26/2006	4.80%
6/6/1991	8.393	8.39%	8.42%	6/27/2006	4.80%
6/5/1991	8.393	8.39%	8.42%	6/28/2006	4.80%
6/4/1991	8.339	8.34%	8.42%	6/29/2006	4.81%
6/3/1991	8.34	8.34%	8.43%	6/30/2006	4.81%
5/31/1991	8.265	8.27%	8.43%	7/3/2006	4.81%
5/30/1991	8.22	8.22%	8.44%	7/4/2006	4.82%
5/29/1991	8.281	8.28%	8.44%	7/5/2006	4.82%
5/28/1991	8.281	8.28%	8.44%	7/6/2006	4.83%
5/27/1991	8.297	8.30%	8.45%	7/7/2006	4.83%
5/24/1991	8.306	8.31%	8.45%	7/10/2006	4.83%
5/23/1991	8.306	8.31%	8.45%	7/11/2006	4.83%
5/22/1991	8.276	8.28%	8.45%	7/12/2006	4.84%
5/21/1991	8.251	8.25%	8.46%	7/13/2006	4.84%
5/20/1991	8.281	8.28%	8.46%	7/14/2006	4.84%
5/17/1991	8.279	8.28%	8.46%	7/17/2006	4.84%
5/16/1991	8.336	8.34%	8.46%	7/18/2006	4.85%
5/15/1991	8.334	8.33%	8.47%	7/19/2006	4.85%
5/14/1991	8.339	8.34%	8.47%	7/20/2006	4.85%
5/13/1991	8.263	8.26%	8.47%	7/21/2006	4.85%
5/10/1991	8.306	8.31%	8.47%	7/24/2006	4.86%
5/9/1991	8.214	8.21%	8.47%	7/25/2006	4.86%
5/8/1991	8.229	8.23%	8.47%	7/26/2006	4.86%
5/7/1991	8.245	8.25%	8.47%	7/27/2006	4.86%
5/6/1991	8.215	8.22%	8.47%	7/28/2006	4.86%

5/3/1991	8.227	8.23%	8.48%	7/31/2006	4.87%
5/2/1991	8.122	8.12%	8.48%	8/1/2006	4.87%
5/1/1991	8.17	8.17%	8.48%	8/2/2006	4.87%
4/30/1991	8.182	8.18%	8.48%	8/3/2006	4.87%
4/29/1991	8.229	8.23%	8.48%	8/4/2006	4.87%
4/26/1991	8.211	8.21%	8.49%	8/7/2006	4.87%
4/25/1991	8.239	8.24%	8.49%	8/8/2006	4.87%
4/24/1991	8.215	8.22%	8.49%	8/9/2006	4.88%
4/23/1991	8.271	8.27%	8.49%	8/10/2006	4.88%
4/22/1991	8.295	8.30%	8.49%	8/11/2006	4.88%
4/19/1991	8.245	8.25%	8.49%	8/14/2006	4.88%
4/18/1991	8.181	8.18%	8.49%	8/15/2006	4.88%
4/17/1991	8.106	8.11%	8.49%	8/16/2006	4.88%
4/16/1991	8.117	8.12%	8.50%	8/17/2006	4.88%
4/15/1991	8.13	8.13%	8.50%	8/18/2006	4.88%
4/12/1991	8.153	8.15%	8.50%	8/21/2006	4.89%
4/11/1991	8.255	8.26%	8.50%	8/22/2006	4.89%
4/10/1991	8.262	8.26%	8.50%	8/23/2006	4.89%
4/9/1991	8.204	8.20%	8.50%	8/24/2006	4.89%
4/8/1991	8.158	8.16%	8.50%	8/25/2006	4.89%
4/5/1991	8.166	8.17%	8.50%	8/28/2006	4.89%
4/4/1991	8.182	8.18%	8.51%	8/29/2006	4.89%
4/3/1991	8.242	8.24%	8.51%	8/30/2006	4.89%
4/2/1991	8.216	8.22%	8.51%	8/31/2006	4.89%
4/1/1991	8.257	8.26%	8.51%	9/1/2006	4.90%
3/29/1991	8.246	8.25%	8.51%	9/4/2006	4.90%
3/28/1991	8.236	8.24%	8.51%	9/5/2006	4.90%
3/27/1991	8.255	8.26%	8.51%	9/6/2006	4.90%
3/26/1991	8.305	8.31%	8.52%	9/7/2006	4.90%
3/25/1991	8.32	8.32%	8.52%	9/8/2006	4.90%
3/22/1991	8.308	8.31%	8.52%	9/11/2006	4.90%
3/21/1991	8.329	8.33%	8.52%	9/12/2006	4.90%
3/20/1991	8.343	8.34%	8.52%	9/13/2006	4.90%
3/19/1991	8.403	8.40%	8.52%	9/14/2006	4.91%
3/18/1991	8.332	8.33%	8.52%	9/15/2006	4.91%
3/15/1991	8.288	8.29%	8.52%	9/18/2006	4.91%
3/14/1991	8.201	8.20%	8.52%	9/19/2006	4.91%
3/13/1991	8.185	8.19%	8.52%	9/20/2006	4.91%
3/12/1991	8.267	8.27%	8.52%	9/21/2006	4.91%
3/11/1991	8.222	8.22%	8.52%	9/22/2006	4.91%
3/8/1991	8.31	8.31%	8.52%	9/25/2006	4.91%
3/7/1991	8.222	8.22%	8.53%	9/26/2006	4.91%
3/6/1991	8.279	8.28%	8.53%	9/27/2006	4.91%
3/5/1991	8.242	8.24%	8.53%	9/28/2006	4.91%
3/4/1991	8.294	8.29%	8.53%	9/29/2006	4.91%
3/1/1991	8.288	8.29%	8.53%	10/2/2006	4.91%
2/28/1991	8.203	8.20%	8.54%	10/3/2006	4.91%

2/27/1991	8.143	8.14%	8.54%	10/4/2006	4.92%
2/26/1991	8.133	8.13%	8.54%	10/5/2006	4.92%
2/25/1991	8.049	8.05%	8.54%	10/6/2006	4.92%
2/22/1991	8.061	8.06%	8.55%	10/9/2006	4.92%
2/21/1991	8.04	8.04%	8.55%	10/10/2006	4.92%
2/20/1991	8.04	8.04%	8.55%	10/11/2006	4.92%
2/19/1991	7.99	7.99%	8.55%	10/12/2006	4.92%
2/18/1991	7.954	7.95%	8.56%	10/13/2006	4.93%
2/15/1991	7.977	7.98%	8.56%	10/16/2006	4.93%
2/14/1991	7.989	7.99%	8.57%	10/17/2006	4.93%
2/13/1991	7.955	7.96%	8.57%	10/18/2006	4.93%
2/12/1991	7.958	7.96%	8.58%	10/19/2006	4.93%
2/11/1991	7.961	7.96%	8.58%	10/20/2006	4.93%
2/8/1991	7.958	7.96%	8.58%	10/23/2006	4.94%
2/7/1991	8.057	8.06%	8.59%	10/24/2006	4.94%
2/6/1991	8.007	8.01%	8.59%	10/25/2006	4.94%
2/5/1991	8.031	8.03%	8.60%	10/26/2006	4.94%
2/4/1991	8.046	8.05%	8.60%	10/27/2006	4.94%
2/1/1991	8.091	8.09%	8.61%	10/30/2006	4.95%
1/31/1991	8.195	8.20%	8.61%	10/31/2006	4.95%
1/30/1991	8.222	8.22%	8.62%	11/1/2006	4.95%
1/29/1991	8.203	8.20%	8.62%	11/2/2006	4.95%
1/28/1991	8.214	8.21%	8.63%	11/3/2006	4.95%
1/25/1991	8.227	8.23%	8.63%	11/6/2006	4.95%
1/24/1991	8.16	8.16%	8.63%	11/7/2006	4.95%
1/23/1991	8.199	8.20%	8.63%	11/8/2006	4.95%
1/22/1991	8.248	8.25%	8.64%	11/9/2006	4.95%
1/21/1991	8.206	8.21%	8.64%	11/10/2006	4.95%
1/18/1991	8.167	8.17%	8.64%	11/13/2006	4.95%
1/17/1991	8.196	8.20%	8.64%	11/14/2006	4.95%
1/16/1991	8.403	8.40%	8.64%	11/15/2006	4.95%
1/15/1991	8.394	8.39%	8.64%	11/16/2006	4.95%
1/14/1991	8.365	8.37%	8.65%	11/17/2006	4.95%
1/11/1991	8.358	8.36%	8.65%	11/20/2006	4.95%
1/10/1991	8.326	8.33%	8.65%	11/21/2006	4.95%
1/9/1991	8.456	8.46%	8.65%	11/22/2006	4.95%
1/8/1991	8.373	8.37%	8.65%	11/23/2006	4.95%
1/7/1991	8.318	8.32%	8.65%	11/24/2006	4.95%
1/4/1991	8.207	8.21%	8.65%	11/27/2006	4.95%
1/3/1991	8.11	8.11%	8.65%	11/28/2006	4.95%
12/31/1990	8.249	8.25%	8.65%	11/29/2006	4.95%
12/28/1990	8.298	8.30%	8.66%	11/30/2006	4.95%
12/27/1990	8.244	8.24%	8.66%	12/1/2006	4.95%
12/26/1990	8.291	8.29%	8.66%	12/4/2006	4.95%
12/25/1990	8.357	8.36%	8.66%	12/5/2006	4.95%
12/24/1990	8.361	8.36%	8.66%	12/6/2006	4.95%
12/21/1990	8.281	8.28%	8.66%	12/7/2006	4.95%

12/20/1990	8.232	8.23%	8.66%	12/8/2006	4.95%
12/19/1990	8.181	8.18%	8.66%	12/11/2006	4.95%
12/18/1990	8.086	8.09%	8.67%	12/12/2006	4.95%
12/17/1990	8.184	8.18%	8.67%	12/13/2006	4.95%
12/14/1990	8.188	8.19%	8.67%	12/14/2006	4.95%
12/13/1990	8.124	8.12%	8.67%	12/15/2006	4.95%
12/12/1990	8.062	8.06%	8.68%	12/18/2006	4.95%
12/11/1990	8.074	8.07%	8.68%	12/19/2006	4.95%
12/10/1990	8.131	8.13%	8.68%	12/20/2006	4.95%
12/7/1990	8.184	8.18%	8.68%	12/21/2006	4.95%
12/6/1990	8.333	8.33%	8.68%	12/22/2006	4.95%
12/5/1990	8.329	8.33%	8.69%	12/25/2006	4.95%
12/4/1990	8.321	8.32%	8.69%	12/26/2006	4.95%
12/3/1990	8.362	8.36%	8.69%	12/27/2006	4.95%
11/30/1990	8.486	8.49%	8.69%	12/28/2006	4.95%
11/29/1990	8.486	8.49%	8.69%	12/29/2006	4.95%
11/28/1990	8.443	8.44%	8.69%	1/1/2007	4.95%
11/27/1990	8.437	8.44%	8.69%	1/2/2007	4.95%
11/26/1990	8.429	8.43%	8.69%	1/3/2007	4.95%
11/23/1990	8.447	8.45%	8.69%	1/4/2007	4.95%
11/22/1990	8.425	8.43%	8.69%	1/5/2007	4.95%
11/21/1990	8.42	8.42%	8.69%	1/8/2007	4.95%
11/20/1990	8.461	8.46%	8.69%	1/9/2007	4.95%
11/19/1990	8.512	8.51%	8.69%	1/10/2007	4.95%
11/16/1990	8.45	8.45%	8.69%	1/11/2007	4.95%
11/15/1990	8.515	8.52%	8.69%	1/12/2007	4.95%
11/14/1990	8.515	8.52%	8.69%	1/15/2007	4.95%
11/13/1990	8.532	8.53%	8.69%	1/16/2007	4.95%
11/12/1990	8.549	8.55%	8.69%	1/17/2007	4.95%
11/9/1990	8.622	8.62%	8.69%	1/18/2007	4.94%
11/8/1990	8.71	8.71%	8.69%	1/19/2007	4.94%
11/7/1990	8.694	8.69%	8.69%	1/22/2007	4.94%
11/6/1990	8.635	8.64%	8.69%	1/23/2007	4.94%
11/5/1990	8.622	8.62%	8.69%	1/24/2007	4.94%
11/2/1990	8.689	8.69%	8.69%	1/25/2007	4.94%
11/1/1990	8.685	8.69%	8.69%	1/26/2007	4.94%
10/31/1990	8.759	8.76%	8.69%	1/29/2007	4.94%
10/30/1990	8.82	8.82%	8.68%	1/30/2007	4.94%
10/29/1990	8.838	8.84%	8.68%	1/31/2007	4.94%
10/26/1990	8.775	8.78%	8.68%	2/1/2007	4.94%
10/25/1990	8.753	8.75%	8.68%	2/2/2007	4.93%
10/24/1990	8.775	8.78%	8.67%	2/5/2007	4.93%
10/23/1990	8.799	8.80%	8.67%	2/6/2007	4.93%
10/22/1990	8.753	8.75%	8.67%	2/7/2007	4.93%
10/19/1990	8.753	8.75%	8.67%	2/8/2007	4.93%
10/18/1990	8.819	8.82%	8.66%	2/9/2007	4.93%
10/17/1990	8.885	8.89%	8.66%	2/12/2007	4.92%

10/16/1990	8.893	8.89%	8.66%	2/13/2007	4.92%
10/15/1990	8.937	8.94%	8.65%	2/14/2007	4.92%
10/12/1990	8.958	8.96%	8.65%	2/15/2007	4.92%
10/11/1990	9.08	9.08%	8.64%	2/16/2007	4.92%
10/10/1990	9.055	9.06%	8.64%	2/19/2007	4.91%
10/9/1990	8.963	8.96%	8.63%	2/20/2007	4.91%
10/8/1990	8.819	8.82%	8.63%	2/21/2007	4.91%
10/5/1990	8.789	8.79%	8.62%	2/22/2007	4.91%
10/4/1990	8.79	8.79%	8.62%	2/23/2007	4.91%
10/3/1990	8.865	8.87%	8.62%	2/26/2007	4.90%
10/2/1990	8.825	8.83%	8.61%	2/27/2007	4.90%
10/1/1990	8.853	8.85%	8.61%	2/28/2007	4.90%
9/28/1990	8.949	8.95%	8.60%	3/1/2007	4.90%
9/27/1990	9.019	9.02%	8.60%	3/2/2007	4.89%
9/26/1990	9.126	9.13%	8.59%	3/5/2007	4.89%
9/25/1990	9.146	9.15%	8.58%	3/6/2007	4.89%
9/24/1990	9.172	9.17%	8.58%	3/7/2007	4.89%
9/21/1990	9.123	9.12%	8.57%	3/8/2007	4.88%
9/20/1990	9.036	9.04%	8.56%	3/9/2007	4.88%
9/19/1990	9.014	9.01%	8.56%	3/12/2007	4.88%
9/18/1990	9.058	9.06%	8.55%	3/13/2007	4.88%
9/17/1990	9.06	9.06%	8.55%	3/14/2007	4.87%
9/14/1990	9.022	9.02%	8.54%	3/15/2007	4.87%
9/13/1990	8.951	8.95%	8.54%	3/16/2007	4.87%
9/12/1990	8.947	8.95%	8.53%	3/19/2007	4.87%
9/11/1990	8.927	8.93%	8.52%	3/20/2007	4.87%
9/10/1990	8.964	8.96%	8.52%	3/21/2007	4.87%
9/7/1990	8.913	8.91%	8.51%	3/22/2007	4.86%
9/6/1990	8.948	8.95%	8.51%	3/23/2007	4.86%
9/5/1990	8.965	8.97%	8.50%	3/26/2007	4.86%
9/4/1990	9.018	9.02%	8.50%	3/27/2007	4.86%
9/3/1990	9.018	9.02%	8.49%	3/28/2007	4.86%
8/31/1990	8.984	8.98%	8.49%	3/29/2007	4.85%
8/30/1990	8.975	8.98%	8.48%	3/30/2007	4.85%
8/29/1990	8.926	8.93%	8.48%	4/2/2007	4.85%
8/28/1990	9.039	9.04%	8.47%	4/3/2007	4.85%
8/27/1990	9.006	9.01%	8.47%	4/4/2007	4.85%
8/24/1990	9.155	9.16%	8.46%	4/5/2007	4.84%
8/23/1990	9.128	9.13%	8.45%	4/6/2007	4.84%
8/22/1990	9.054	9.05%	8.45%	4/9/2007	4.84%
8/21/1990	8.937	8.94%	8.44%	4/10/2007	4.84%
8/20/1990	8.919	8.92%	8.44%	4/11/2007	4.84%
8/17/1990	8.943	8.94%	8.43%	4/12/2007	4.84%
8/16/1990	8.908	8.91%	8.43%	4/13/2007	4.84%
8/15/1990	8.759	8.76%	8.42%	4/16/2007	4.83%
8/14/1990	8.783	8.78%	8.42%	4/17/2007	4.83%
8/13/1990	8.807	8.81%	8.41%	4/18/2007	4.83%

8/10/1990	8.777	8.78%	8.41%	4/19/2007	4.83%
8/9/1990	8.756	8.76%	8.40%	4/20/2007	4.83%
8/8/1990	8.841	8.84%	8.40%	4/23/2007	4.83%
8/7/1990	8.842	8.84%	8.39%	4/24/2007	4.83%
8/6/1990	8.802	8.80%	8.39%	4/25/2007	4.82%
8/3/1990	8.555	8.56%	8.38%	4/26/2007	4.82%
8/2/1990	8.458	8.46%	8.38%	4/27/2007	4.82%
8/1/1990	8.353	8.35%	8.38%	4/30/2007	4.82%
7/31/1990	8.411	8.41%	8.38%	5/1/2007	4.82%
7/30/1990	8.405	8.41%	8.37%	5/2/2007	4.82%
7/27/1990	8.478	8.48%	8.37%	5/3/2007	4.82%
7/26/1990	8.538	8.54%	8.37%	5/4/2007	4.82%
7/25/1990	8.545	8.55%	8.37%	5/7/2007	4.81%
7/24/1990	8.585	8.59%	8.36%	5/8/2007	4.81%
7/23/1990	8.553	8.55%	8.36%	5/9/2007	4.81%
7/20/1990	8.538	8.54%	8.36%	5/10/2007	4.81%
7/19/1990	8.553	8.55%	8.36%	5/11/2007	4.81%
7/18/1990	8.545	8.55%	8.35%	5/14/2007	4.81%
7/17/1990	8.459	8.46%	8.35%	5/15/2007	4.81%
7/16/1990	8.456	8.46%	8.35%	5/16/2007	4.81%
7/13/1990	8.449	8.45%	8.35%	5/17/2007	4.81%
7/12/1990	8.497	8.50%	8.35%	5/18/2007	4.81%
7/11/1990	8.561	8.56%	8.34%	5/21/2007	4.80%
7/10/1990	8.555	8.56%	8.34%	5/22/2007	4.80%
7/9/1990	8.545	8.55%	8.34%	5/23/2007	4.80%
7/6/1990	8.505	8.51%	8.34%	5/24/2007	4.80%
7/5/1990	8.404	8.40%	8.34%	5/25/2007	4.80%
7/4/1990	8.383	8.38%	8.34%	5/28/2007	4.80%
7/3/1990	8.388	8.39%	8.34%	5/29/2007	4.81%
7/2/1990	8.399	8.40%	8.34%	5/30/2007	4.81%
6/29/1990	8.4	8.40%	8.33%	5/31/2007	4.81%
6/28/1990	8.439	8.44%	8.33%	6/1/2007	4.81%
6/27/1990	8.48	8.48%	8.33%	6/4/2007	4.81%
6/26/1990	8.51	8.51%	8.33%	6/5/2007	4.81%
6/25/1990	8.565	8.57%	8.33%	6/6/2007	4.81%
6/22/1990	8.48	8.48%	8.32%	6/7/2007	4.81%
6/21/1990	8.492	8.49%	8.32%	6/8/2007	4.81%
6/20/1990	8.513	8.51%	8.32%	6/11/2007	4.81%
6/19/1990	8.48	8.48%	8.32%	6/12/2007	4.82%
6/18/1990	8.461	8.46%	8.32%	6/13/2007	4.82%
6/15/1990	8.424	8.42%	8.32%	6/14/2007	4.82%
6/14/1990	8.345	8.35%	8.31%	6/15/2007	4.82%
6/13/1990	8.383	8.38%	8.31%	6/18/2007	4.82%
6/12/1990	8.457	8.46%	8.31%	6/19/2007	4.82%
6/11/1990	8.447	8.45%	8.31%	6/20/2007	4.83%
6/8/1990	8.443	8.44%	8.31%	6/21/2007	4.83%
6/7/1990	8.426	8.43%	8.31%	6/22/2007	4.83%

6/6/1990	8.442	8.44%	8.31%	6/25/2007	4.83%
6/5/1990	8.449	8.45%	8.31%	6/26/2007	4.83%
6/4/1990	8.425	8.43%	8.30%	6/27/2007	4.83%
6/1/1990	8.419	8.42%	8.30%	6/28/2007	4.84%
5/31/1990	8.578	8.58%	8.30%	6/29/2007	4.84%
5/30/1990	8.594	8.59%	8.30%	7/2/2007	4.84%
5/29/1990	8.618	8.62%	8.30%	7/3/2007	4.84%
5/28/1990	8.679	8.68%	8.30%	7/4/2007	4.85%
5/25/1990	8.668	8.67%	8.29%	7/5/2007	4.85%
5/24/1990	8.611	8.61%	8.29%	7/6/2007	4.85%
5/23/1990	8.575	8.58%	8.29%	7/9/2007	4.85%
5/22/1990	8.613	8.61%	8.29%	7/10/2007	4.85%
5/21/1990	8.688	8.69%	8.28%	7/11/2007	4.86%
5/18/1990	8.702	8.70%	8.28%	7/12/2007	4.86%
5/17/1990	8.655	8.66%	8.28%	7/13/2007	4.86%
5/16/1990	8.639	8.64%	8.27%	7/16/2007	4.86%
5/15/1990	8.616	8.62%	8.27%	7/17/2007	4.86%
5/14/1990	8.579	8.58%	8.27%	7/18/2007	4.86%
5/11/1990	8.641	8.64%	8.27%	7/19/2007	4.87%
5/10/1990	8.847	8.85%	8.26%	7/20/2007	4.87%
5/9/1990	8.868	8.87%	8.26%	7/23/2007	4.87%
5/8/1990	8.825	8.83%	8.25%	7/24/2007	4.87%
5/7/1990	8.841	8.84%	8.25%	7/25/2007	4.87%
5/4/1990	8.816	8.82%	8.24%	7/26/2007	4.87%
5/3/1990	8.973	8.97%	8.24%	7/27/2007	4.87%
5/2/1990	9.034	9.03%	8.24%	7/30/2007	4.87%
5/1/1990	9.034	9.03%	8.23%	7/31/2007	4.87%
4/30/1990	8.994	8.99%	8.23%	8/1/2007	4.87%
4/27/1990	9.021	9.02%	8.22%	8/2/2007	4.87%
4/26/1990	9.041	9.04%	8.22%	8/3/2007	4.87%
4/25/1990	8.983	8.98%	8.21%	8/6/2007	4.87%
4/24/1990	8.961	8.96%	8.21%	8/7/2007	4.87%
4/23/1990	8.961	8.96%	8.21%	8/8/2007	4.87%
4/20/1990	8.943	8.94%	8.20%	8/9/2007	4.87%
4/19/1990	8.847	8.85%	8.20%	8/10/2007	4.88%
4/18/1990	8.844	8.84%	8.19%	8/13/2007	4.88%
4/17/1990	8.717	8.72%	8.19%	8/14/2007	4.88%
4/16/1990	8.637	8.64%	8.18%	8/15/2007	4.88%
4/13/1990	8.576	8.58%	8.18%	8/16/2007	4.88%
4/12/1990	8.594	8.59%	8.18%	8/17/2007	4.88%
4/11/1990	8.575	8.58%	8.18%	8/20/2007	4.88%
4/10/1990	8.589	8.59%	8.17%	8/21/2007	4.88%
4/9/1990	8.548	8.55%	8.17%	8/22/2007	4.89%
4/6/1990	8.521	8.52%	8.17%	8/23/2007	4.89%
4/5/1990	8.519	8.52%	8.17%	8/24/2007	4.89%
4/4/1990	8.509	8.51%	8.17%	8/27/2007	4.89%
4/3/1990	8.615	8.62%	8.16%	8/28/2007	4.89%

4/2/1990	8.631	8.63%	8.16%	8/29/2007	4.89%
3/30/1990	8.626	8.63%	8.16%	8/30/2007	4.89%
3/29/1990	8.585	8.59%	8.16%	8/31/2007	4.89%
3/28/1990	8.463	8.46%	8.16%	9/3/2007	4.89%
3/27/1990	8.47	8.47%	8.16%	9/4/2007	4.89%
3/26/1990	8.463	8.46%	8.16%	9/5/2007	4.90%
3/23/1990	8.478	8.48%	8.15%	9/6/2007	4.90%
3/22/1990	8.486	8.49%	8.15%	9/7/2007	4.90%
3/21/1990	8.493	8.49%	8.15%	9/10/2007	4.90%
3/20/1990	8.457	8.46%	8.15%	9/11/2007	4.90%
3/19/1990	8.534	8.53%	8.15%	9/12/2007	4.90%
3/16/1990	8.54	8.54%	8.15%	9/13/2007	4.90%
3/15/1990	8.615	8.62%	8.15%	9/14/2007	4.90%
3/14/1990	8.605	8.61%	8.15%	9/17/2007	4.90%
3/13/1990	8.713	8.71%	8.15%	9/18/2007	4.90%
3/12/1990	8.615	8.62%	8.15%	9/19/2007	4.90%
3/9/1990	8.624	8.62%	8.15%	9/20/2007	4.90%
3/8/1990	8.552	8.55%	8.15%	9/21/2007	4.90%
3/7/1990	8.598	8.60%	8.15%	9/24/2007	4.90%
3/6/1990	8.571	8.57%	8.15%	9/25/2007	4.91%
3/5/1990	8.651	8.65%	8.15%	9/26/2007	4.91%
3/2/1990	8.548	8.55%	8.15%	9/27/2007	4.91%
3/1/1990	8.605	8.61%	8.15%	9/28/2007	4.91%
2/28/1990	8.542	8.54%	8.15%	10/1/2007	4.91%
2/27/1990	8.447	8.45%	8.15%	10/2/2007	4.91%
2/26/1990	8.484	8.48%	8.15%	10/3/2007	4.91%
2/23/1990	8.557	8.56%	8.15%	10/4/2007	4.91%
2/22/1990	8.566	8.57%	8.15%	10/5/2007	4.91%
2/21/1990	8.641	8.64%	8.15%	10/8/2007	4.91%
2/20/1990	8.659	8.66%	8.15%	10/9/2007	4.91%
2/19/1990	8.521	8.52%	8.16%	10/10/2007	4.91%
2/16/1990	8.46	8.46%	8.16%	10/11/2007	4.91%
2/15/1990	8.457	8.46%	8.16%	10/12/2007	4.91%
2/14/1990	8.413	8.41%	8.16%	10/15/2007	4.91%
2/13/1990	8.383	8.38%	8.17%	10/16/2007	4.91%
2/12/1990	8.43	8.43%	8.17%	10/17/2007	4.91%
2/9/1990	8.331	8.33%	8.17%	10/18/2007	4.91%
2/8/1990	8.483	8.48%	8.18%	10/19/2007	4.91%
2/7/1990	8.544	8.54%	8.18%	10/22/2007	4.91%
2/6/1990	8.588	8.59%	8.18%	10/23/2007	4.91%
2/5/1990	8.535	8.54%	8.18%	10/24/2007	4.91%
2/2/1990	8.51	8.51%	8.18%	10/25/2007	4.91%
2/1/1990	8.429	8.43%	8.19%	10/26/2007	4.91%
1/31/1990	8.452	8.45%	8.19%	10/29/2007	4.91%
1/30/1990	8.545	8.55%	8.19%	10/30/2007	4.91%
1/29/1990	8.578	8.58%	8.19%	10/31/2007	4.90%
1/26/1990	8.522	8.52%	8.20%	11/1/2007	4.90%

1/25/1990	8.457	8.46%	8.20%	11/2/2007	4.90%
1/24/1990	8.411	8.41%	8.20%	11/5/2007	4.90%
1/23/1990	8.391	8.39%	8.20%	11/6/2007	4.90%
1/22/1990	8.309	8.31%	8.21%	11/7/2007	4.90%
1/19/1990	8.27	8.27%	8.21%	11/8/2007	4.89%
1/18/1990	8.338	8.34%	8.22%	11/9/2007	4.89%
1/17/1990	8.248	8.25%	8.22%	11/12/2007	4.89%
1/16/1990	8.254	8.25%	8.22%	11/13/2007	4.89%
1/15/1990	8.185	8.19%	8.23%	11/14/2007	4.89%
1/12/1990	8.171	8.17%	8.23%	11/15/2007	4.89%
1/11/1990	8.115	8.12%	8.24%	11/16/2007	4.89%
1/10/1990	8.085	8.09%	8.24%	11/19/2007	4.88%
1/9/1990	8.094	8.09%	8.25%	11/20/2007	4.88%
1/8/1990	8.094	8.09%	8.25%	11/21/2007	4.88%
1/5/1990	8.056	8.06%	8.26%	11/22/2007	4.88%
1/4/1990	8.035	8.04%	8.26%	11/23/2007	4.88%
1/3/1990	8.034	8.03%	8.27%	11/26/2007	4.87%
1/2/1990	7.99	7.99%	8.27%	11/27/2007	4.87%
12/29/1989	7.978	7.98%	8.28%	11/28/2007	4.87%
12/28/1989	7.961	7.96%	8.29%	11/29/2007	4.87%
12/27/1989	7.98	7.98%	8.29%	11/30/2007	4.87%
12/26/1989	7.986	7.99%	8.30%	12/3/2007	4.86%
12/22/1989	7.874	7.87%	8.31%	12/4/2007	4.86%
12/21/1989	7.852	7.85%	8.31%	12/5/2007	4.86%
12/20/1989	7.839	7.84%	8.32%	12/6/2007	4.86%
12/19/1989	7.842	7.84%	8.33%	12/7/2007	4.86%
12/18/1989	7.839	7.84%	8.33%	12/10/2007	4.86%
12/15/1989	7.851	7.85%	8.34%	12/11/2007	4.86%
12/14/1989	7.852	7.85%	8.34%	12/12/2007	4.86%
12/13/1989	7.882	7.88%	8.35%	12/13/2007	4.86%
12/12/1989	7.892	7.89%	8.36%	12/14/2007	4.86%
12/11/1989	7.891	7.89%	8.36%	12/17/2007	4.86%
12/8/1989	7.879	7.88%	8.37%	12/18/2007	4.86%
12/7/1989	7.919	7.92%	8.37%	12/19/2007	4.86%
12/6/1989	7.908	7.91%	8.38%	12/20/2007	4.85%
12/5/1989	7.882	7.88%	8.39%	12/21/2007	4.85%
12/4/1989	7.875	7.88%	8.39%	12/24/2007	4.85%
12/1/1989	7.879	7.88%	8.40%	12/25/2007	4.85%
11/30/1989	7.89	7.89%	8.41%	12/26/2007	4.85%
11/29/1989	7.923	7.92%	8.41%	12/27/2007	4.85%
11/28/1989	7.908	7.91%	8.42%	12/28/2007	4.85%
11/27/1989	7.912	7.91%	8.42%	12/31/2007	4.85%
11/24/1989	7.872	7.87%	8.43%	1/1/2008	4.85%
11/23/1989	7.87	7.87%	8.44%	1/2/2008	4.84%
11/22/1989	7.871	7.87%	8.44%	1/3/2008	4.84%
11/21/1989	7.899	7.90%	8.45%	1/4/2008	4.84%
11/20/1989	7.917	7.92%	8.45%	1/7/2008	4.84%

11/17/1989	7.929	7.93%	8.46%	1/8/2008	4.83%
11/16/1989	7.864	7.86%	8.46%	1/9/2008	4.83%
11/15/1989	7.858	7.86%	8.47%	1/10/2008	4.83%
11/14/1989	7.884	7.88%	8.47%	1/11/2008	4.83%
11/13/1989	7.884	7.88%	8.48%	1/14/2008	4.82%
11/10/1989	7.895	7.90%	8.48%	1/15/2008	4.82%
11/9/1989	7.895	7.90%	8.49%	1/16/2008	4.82%
11/8/1989	7.878	7.88%	8.49%	1/17/2008	4.81%
11/7/1989	7.872	7.87%	8.49%	1/18/2008	4.81%
11/6/1989	7.952	7.95%	8.50%	1/21/2008	4.81%
11/3/1989	7.934	7.93%	8.50%	1/22/2008	4.81%
11/2/1989	7.874	7.87%	8.51%	1/23/2008	4.80%
11/1/1989	7.879	7.88%	8.51%	1/24/2008	4.80%
10/31/1989	7.906	7.91%	8.52%	1/25/2008	4.80%
10/30/1989	7.923	7.92%	8.52%	1/28/2008	4.80%
10/27/1989	7.942	7.94%	8.53%	1/29/2008	4.79%
10/26/1989	7.883	7.88%	8.53%	1/30/2008	4.79%
10/25/1989	7.887	7.89%	8.54%	1/31/2008	4.79%
10/24/1989	7.889	7.89%	8.54%	2/1/2008	4.78%
10/23/1989	7.936	7.94%	8.55%	2/4/2008	4.78%
10/20/1989	7.98	7.98%	8.55%	2/5/2008	4.78%
10/19/1989	7.961	7.96%	8.56%	2/6/2008	4.78%
10/18/1989	8.039	8.04%	8.56%	2/7/2008	4.78%
10/17/1989	8.03	8.03%	8.57%	2/8/2008	4.77%
10/16/1989	7.974	7.97%	8.57%	2/11/2008	4.77%
10/13/1989	7.871	7.87%	8.58%	2/12/2008	4.77%
10/12/1989	8.046	8.05%	8.59%	2/13/2008	4.77%
10/11/1989	8.055	8.06%	8.59%	2/14/2008	4.77%
10/10/1989	8.011	8.01%	8.59%	2/15/2008	4.77%
10/9/1989	8	8.00%	8.60%	2/18/2008	4.77%
10/6/1989	8.009	8.01%	8.60%	2/19/2008	4.76%
10/5/1989	8.071	8.07%	8.61%	2/20/2008	4.76%
10/4/1989	8.163	8.16%	8.61%	2/21/2008	4.76%
10/3/1989	8.162	8.16%	8.62%	2/22/2008	4.76%
10/2/1989	8.216	8.22%	8.62%	2/25/2008	4.76%
9/29/1989	8.236	8.24%	8.63%	2/26/2008	4.76%
9/28/1989	8.246	8.25%	8.63%	2/27/2008	4.75%
9/27/1989	8.246	8.25%	8.63%	2/28/2008	4.75%
9/26/1989	8.286	8.29%	8.64%	2/29/2008	4.75%
9/25/1989	8.286	8.29%	8.64%	3/3/2008	4.75%
9/22/1989	8.192	8.19%	8.64%	3/4/2008	4.74%
9/21/1989	8.185	8.19%	8.65%	3/5/2008	4.74%
9/20/1989	8.165	8.17%	8.65%	3/6/2008	4.74%
9/19/1989	8.088	8.09%	8.66%	3/7/2008	4.74%
9/18/1989	8.09	8.09%	8.66%	3/10/2008	4.73%
9/15/1989	8.076	8.08%	8.67%	3/11/2008	4.73%
9/14/1989	8.098	8.10%	8.67%	3/12/2008	4.73%

9/13/1989	8.147	8.15%	8.68%	3/13/2008	4.72%
9/12/1989	8.1	8.10%	8.68%	3/14/2008	4.72%
9/11/1989	8.066	8.07%	8.69%	3/17/2008	4.71%
9/8/1989	8.082	8.08%	8.69%	3/18/2008	4.71%
9/7/1989	8.116	8.12%	8.70%	3/19/2008	4.70%
9/6/1989	8.101	8.10%	8.70%	3/20/2008	4.70%
9/5/1989	8.13	8.13%	8.71%	3/21/2008	4.69%
9/4/1989	8.139	8.14%	8.71%	3/24/2008	4.69%
9/1/1989	8.129	8.13%	8.72%	3/25/2008	4.68%
8/31/1989	8.204	8.20%	8.72%	3/26/2008	4.68%
8/30/1989	8.177	8.18%	8.73%	3/27/2008	4.68%
8/29/1989	8.205	8.21%	8.73%	3/28/2008	4.67%
8/28/1989	8.231	8.23%	8.73%	3/31/2008	4.67%
8/25/1989	8.19	8.19%	8.74%	4/1/2008	4.66%
8/24/1989	8.155	8.16%	8.74%	4/2/2008	4.66%
8/23/1989	8.17	8.17%	8.74%	4/3/2008	4.65%
8/22/1989	8.251	8.25%	8.75%	4/4/2008	4.65%
8/21/1989	8.177	8.18%	8.75%	4/7/2008	4.65%
8/18/1989	8.158	8.16%	8.75%	4/8/2008	4.64%
8/17/1989	8.159	8.16%	8.76%	4/9/2008	4.64%
8/16/1989	8.113	8.11%	8.76%	4/10/2008	4.63%
8/15/1989	8.158	8.16%	8.76%	4/11/2008	4.63%
8/14/1989	8.241	8.24%	8.77%	4/14/2008	4.62%
8/11/1989	8.11	8.11%	8.77%	4/15/2008	4.62%
8/10/1989	8.057	8.06%	8.77%	4/16/2008	4.62%
8/9/1989	8.141	8.14%	8.78%	4/17/2008	4.61%
8/8/1989	8.084	8.08%	8.78%	4/18/2008	4.61%
8/7/1989	8.082	8.08%	8.79%	4/21/2008	4.61%
8/4/1989	8.079	8.08%	8.79%	4/22/2008	4.60%
8/3/1989	7.9	7.90%	8.79%	4/23/2008	4.60%
8/2/1989	7.835	7.84%	8.80%	4/24/2008	4.60%
8/1/1989	7.846	7.85%	8.80%	4/25/2008	4.60%
7/31/1989	7.92	7.92%	8.81%	4/28/2008	4.59%
7/28/1989	7.99	7.99%	8.81%	4/29/2008	4.59%
7/27/1989	8.027	8.03%	8.82%	4/30/2008	4.59%
7/26/1989	8.104	8.10%	8.82%	5/1/2008	4.59%
7/25/1989	8.113	8.11%	8.83%	5/2/2008	4.58%
7/24/1989	8.128	8.13%	8.83%	5/5/2008	4.58%
7/21/1989	8.152	8.15%	8.83%	5/6/2008	4.58%
7/20/1989	8.134	8.13%	8.84%	5/7/2008	4.58%
7/19/1989	8.138	8.14%	8.84%	5/8/2008	4.58%
7/18/1989	8.188	8.19%	8.85%	5/9/2008	4.58%
7/17/1989	8.124	8.12%	8.85%	5/12/2008	4.57%
7/14/1989	8.083	8.08%	8.86%	5/13/2008	4.57%
7/13/1989	8.054	8.05%	8.86%	5/14/2008	4.57%
7/12/1989	8.032	8.03%	8.87%	5/15/2008	4.57%
7/11/1989	8.017	8.02%	8.87%	5/16/2008	4.57%

7/10/1989	8.009	8.01%	8.88%	5/19/2008	4.56%
7/7/1989	8.039	8.04%	8.88%	5/20/2008	4.56%
7/6/1989	8.09	8.09%	8.89%	5/21/2008	4.56%
7/5/1989	8.13	8.13%	8.89%	5/22/2008	4.56%
7/3/1989	8.072	8.07%	8.90%	5/23/2008	4.56%
6/30/1989	8.037	8.04%	8.90%	5/26/2008	4.55%
6/29/1989	8.097	8.10%	8.91%	5/27/2008	4.55%
6/28/1989	8.14	8.14%	8.91%	5/28/2008	4.55%
6/27/1989	8.072	8.07%	8.91%	5/29/2008	4.55%
6/26/1989	8.152	8.15%	8.92%	5/30/2008	4.55%
6/23/1989	8.195	8.20%	8.92%	6/2/2008	4.55%
6/22/1989	8.326	8.33%	8.93%	6/3/2008	4.55%
6/21/1989	8.341	8.34%	8.93%	6/4/2008	4.55%
6/20/1989	8.282	8.28%	8.94%	6/5/2008	4.54%
6/19/1989	8.345	8.35%	8.94%	6/6/2008	4.54%
6/16/1989	8.301	8.30%	8.95%	6/9/2008	4.54%
6/15/1989	8.292	8.29%	8.95%	6/10/2008	4.54%
6/14/1989	8.164	8.16%	8.96%	6/11/2008	4.54%
6/13/1989	8.217	8.22%	8.96%	6/12/2008	4.54%
6/12/1989	8.135	8.14%	8.97%	6/13/2008	4.54%
6/9/1989	8.135	8.14%	8.98%	6/16/2008	4.54%
6/8/1989	8.298	8.30%	8.98%	6/17/2008	4.54%
6/7/1989	8.319	8.32%	8.99%	6/18/2008	4.54%
6/6/1989	8.399	8.40%	8.99%	6/19/2008	4.54%
6/5/1989	8.435	8.44%	9.00%	6/20/2008	4.54%
6/2/1989	8.451	8.45%	9.00%	6/23/2008	4.54%
6/1/1989	8.598	8.60%	9.01%	6/24/2008	4.54%
5/31/1989	8.595	8.60%	9.01%	6/25/2008	4.54%
5/30/1989	8.628	8.63%	9.02%	6/26/2008	4.54%
5/29/1989	8.6	8.60%	9.02%	6/27/2008	4.54%
5/26/1989	8.617	8.62%	9.02%	6/30/2008	4.54%
5/25/1989	8.677	8.68%	9.03%	7/1/2008	4.54%
5/24/1989	8.625	8.63%	9.03%	7/2/2008	4.53%
5/23/1989	8.615	8.62%	9.03%	7/3/2008	4.53%
5/22/1989	8.6	8.60%	9.03%	7/4/2008	4.53%
5/19/1989	8.705	8.71%	9.03%	7/7/2008	4.53%
5/18/1989	8.769	8.77%	9.04%	7/8/2008	4.53%
5/17/1989	8.806	8.81%	9.04%	7/9/2008	4.53%
5/16/1989	8.818	8.82%	9.04%	7/10/2008	4.52%
5/15/1989	8.848	8.85%	9.04%	7/11/2008	4.52%
5/12/1989	8.836	8.84%	9.04%	7/14/2008	4.52%
5/11/1989	9.062	9.06%	9.05%	7/15/2008	4.52%
5/10/1989	9.103	9.10%	9.05%	7/16/2008	4.52%
5/9/1989	9.095	9.10%	9.05%	7/17/2008	4.52%
5/8/1989	8.988	8.99%	9.05%	7/18/2008	4.51%
5/5/1989	8.956	8.96%	9.05%	7/21/2008	4.51%
5/4/1989	8.993	8.99%	9.05%	7/22/2008	4.51%

5/3/1989	8.988	8.99%	9.05%	7/23/2008	4.51%
5/2/1989	8.944	8.94%	9.05%	7/24/2008	4.51%
5/1/1989	8.99	8.99%	9.05%	7/25/2008	4.51%
4/28/1989	8.928	8.93%	9.05%	7/28/2008	4.51%
4/27/1989	8.907	8.91%	9.05%	7/29/2008	4.51%
4/26/1989	8.959	8.96%	9.06%	7/30/2008	4.51%
4/25/1989	8.95	8.95%	9.06%	7/31/2008	4.51%
4/24/1989	8.983	8.98%	9.06%	8/1/2008	4.51%
4/21/1989	8.983	8.98%	9.06%	8/4/2008	4.51%
4/20/1989	9.017	9.02%	9.05%	8/5/2008	4.51%
4/19/1989	8.947	8.95%	9.05%	8/6/2008	4.51%
4/18/1989	8.938	8.94%	9.05%	8/7/2008	4.51%
4/17/1989	9.054	9.05%	9.05%	8/8/2008	4.51%
4/14/1989	9.029	9.03%	9.05%	8/11/2008	4.51%
4/13/1989	9.151	9.15%	9.05%	8/12/2008	4.51%
4/12/1989	9.104	9.10%	9.05%	8/13/2008	4.50%
4/11/1989	9.095	9.10%	9.05%	8/14/2008	4.50%
4/10/1989	9.107	9.11%	9.05%	8/15/2008	4.50%
4/7/1989	9.104	9.10%	9.05%	8/18/2008	4.50%
4/6/1989	9.042	9.04%	9.05%	8/19/2008	4.50%
4/5/1989	9.023	9.02%	9.05%	8/20/2008	4.50%
4/4/1989	9.011	9.01%	9.05%	8/21/2008	4.50%
4/3/1989	9.07	9.07%	9.05%	8/22/2008	4.50%
3/31/1989	9.092	9.09%	9.05%	8/25/2008	4.50%
3/30/1989	9.148	9.15%	9.05%	8/26/2008	4.50%
3/29/1989	9.117	9.12%	9.05%	8/27/2008	4.50%
3/28/1989	9.183	9.18%	9.05%	8/28/2008	4.50%
3/27/1989	9.224	9.22%	9.05%	8/29/2008	4.50%
3/23/1989	9.221	9.22%	9.05%	9/1/2008	4.50%
3/22/1989	9.234	9.23%	9.05%	9/2/2008	4.50%
3/21/1989	9.288	9.29%	9.04%	9/3/2008	4.50%
3/20/1989	9.327	9.33%	9.04%	9/4/2008	4.50%
3/17/1989	9.288	9.29%	9.04%	9/5/2008	4.50%
3/16/1989	9.114	9.11%	9.04%	9/8/2008	4.50%
3/15/1989	9.117	9.12%	9.05%	9/9/2008	4.50%
3/14/1989	9.114	9.11%	9.05%	9/10/2008	4.50%
3/13/1989	9.158	9.16%	9.05%	9/11/2008	4.49%
3/10/1989	9.152	9.15%	9.05%	9/12/2008	4.49%
3/9/1989	9.058	9.06%	9.05%	9/15/2008	4.49%
3/8/1989	9.046	9.05%	9.05%	9/16/2008	4.49%
3/7/1989	9.083	9.08%	9.05%	9/17/2008	4.49%
3/6/1989	9.071	9.07%	9.05%	9/18/2008	4.48%
3/3/1989	9.121	9.12%	9.05%	9/19/2008	4.48%
3/2/1989	9.114	9.11%	9.05%	9/22/2008	4.48%
3/1/1989	9.184	9.18%	9.05%	9/23/2008	4.48%
2/28/1989	9.114	9.11%	9.05%	9/24/2008	4.48%
2/27/1989	9.155	9.16%	9.05%	9/25/2008	4.48%

2/24/1989	9.184	9.18%	9.05%	9/26/2008	4.48%
2/23/1989	9.14	9.14%	9.05%	9/29/2008	4.48%
2/22/1989	9.115	9.12%	9.05%	9/30/2008	4.48%
2/21/1989	9.053	9.05%	9.05%	10/1/2008	4.47%
2/17/1989	9.043	9.04%	9.05%	10/2/2008	4.47%
2/16/1989	9.053	9.05%	9.05%	10/3/2008	4.47%
2/15/1989	9.078	9.08%	9.05%	10/6/2008	4.47%
2/14/1989	9.109	9.11%	9.05%	10/7/2008	4.46%
2/13/1989	9.065	9.07%	9.05%	10/8/2008	4.46%
2/10/1989	9.034	9.03%	9.05%	10/9/2008	4.46%
2/9/1989	8.987	8.99%	9.05%	10/10/2008	4.46%
2/8/1989	8.832	8.83%	9.05%	10/13/2008	4.46%
2/7/1989	8.791	8.79%	9.05%	10/14/2008	4.46%
2/6/1989	8.85	8.85%	9.05%	10/15/2008	4.46%
2/3/1989	8.826	8.83%	9.05%	10/16/2008	4.46%
2/2/1989	8.808	8.81%	9.05%	10/17/2008	4.46%
2/1/1989	8.806	8.81%	9.06%	10/20/2008	4.46%
1/31/1989	8.82	8.82%	9.05%	10/21/2008	4.46%
1/30/1989	8.811	8.81%	9.05%	10/22/2008	4.45%
1/27/1989	8.762	8.76%	9.05%	10/23/2008	4.45%
1/26/1989	8.803	8.80%	9.05%	10/24/2008	4.45%
1/25/1989	8.814	8.81%	9.05%	10/27/2008	4.45%
1/24/1989	8.785	8.79%	9.05%	10/28/2008	4.45%
1/23/1989	8.856	8.86%	9.05%	10/29/2008	4.45%
1/20/1989	8.882	8.88%	9.05%	10/30/2008	4.45%
1/19/1989	8.85	8.85%	9.05%	10/31/2008	4.45%
1/18/1989	8.82	8.82%	9.05%	11/3/2008	4.45%
1/17/1989	8.885	8.89%	9.05%	11/4/2008	4.45%
1/13/1989	8.879	8.88%	9.05%	11/5/2008	4.45%
1/12/1989	8.975	8.98%	9.05%	11/6/2008	4.45%
1/11/1989	9.048	9.05%	9.05%	11/7/2008	4.45%
1/10/1989	9.042	9.04%	9.05%	11/10/2008	4.45%
1/9/1989	9.048	9.05%	9.05%	11/11/2008	4.45%
1/6/1989	9.03	9.03%	9.04%	11/12/2008	4.45%
1/5/1989	9.091	9.09%	9.04%	11/13/2008	4.45%
1/4/1989	9.085	9.09%	9.04%	11/14/2008	4.44%
1/3/1989	9.079	9.08%	9.04%	11/17/2008	4.44%
12/30/1988	8.991	8.99%	9.04%	11/18/2008	4.44%
12/29/1988	9.006	9.01%	9.03%	11/19/2008	4.44%
12/28/1988	9	9.00%	9.03%	11/20/2008	4.43%
12/27/1988	8.964	8.96%	9.03%	11/21/2008	4.43%
12/23/1988	8.898	8.90%	9.03%	11/24/2008	4.42%
12/22/1988	8.934	8.93%	9.02%	11/25/2008	4.42%
12/21/1988	8.94	8.94%	9.02%	11/26/2008	4.41%
12/20/1988	8.946	8.95%	9.02%	11/27/2008	4.41%
12/19/1988	9.036	9.04%	9.02%	11/28/2008	4.40%
12/16/1988	9.049	9.05%	9.01%	12/1/2008	4.40%

12/15/1988	9.049	9.05%	9.01%	12/2/2008	4.39%
12/14/1988	9.043	9.04%	9.01%	12/3/2008	4.38%
12/13/1988	8.97	8.97%	9.00%	12/4/2008	4.37%
12/12/1988	8.946	8.95%	9.00%	12/5/2008	4.37%
12/9/1988	8.946	8.95%	9.00%	12/8/2008	4.36%
12/8/1988	8.97	8.97%	8.99%	12/9/2008	4.35%
12/7/1988	8.97	8.97%	8.99%	12/10/2008	4.35%
12/6/1988	8.934	8.93%	8.99%	12/11/2008	4.34%
12/5/1988	9.123	9.12%	8.99%	12/12/2008	4.33%
12/2/1988	9.163	9.16%	8.98%	12/15/2008	4.32%
12/1/1988	9.025	9.03%	8.98%	12/16/2008	4.31%
11/30/1988	9.068	9.07%	8.98%	12/17/2008	4.31%
11/29/1988	9.123	9.12%	8.97%	12/18/2008	4.30%
11/28/1988	9.145	9.15%	8.97%	12/19/2008	4.29%
11/25/1988	9.173	9.17%	8.96%	12/22/2008	4.28%
11/23/1988	9.102	9.10%	8.96%	12/23/2008	4.27%
11/22/1988	9.105	9.11%	8.96%	12/24/2008	4.26%
11/21/1988	9.105	9.11%	8.95%	12/25/2008	4.25%
11/18/1988	9.108	9.11%	8.95%	12/26/2008	4.25%
11/17/1988	9.176	9.18%	8.95%	12/29/2008	4.24%
11/16/1988	9.108	9.11%	8.94%	12/30/2008	4.23%
11/15/1988	9.011	9.01%	8.94%	12/31/2008	4.22%
11/14/1988	8.999	9.00%	8.94%	1/1/2009	4.21%
11/10/1988	8.981	8.98%	8.93%	1/2/2009	4.20%
11/9/1988	8.993	8.99%	8.93%	1/5/2009	4.20%
11/8/1988	8.933	8.93%	8.93%	1/6/2009	4.19%
11/7/1988	8.957	8.96%	8.93%	1/7/2009	4.18%
11/4/1988	8.909	8.91%	8.93%	1/8/2009	4.18%
11/3/1988	8.734	8.73%	8.93%	1/9/2009	4.17%
11/2/1988	8.786	8.79%	8.93%	1/12/2009	4.16%
11/1/1988	8.775	8.78%	8.93%	1/13/2009	4.16%
10/31/1988	8.74	8.74%	8.93%	1/14/2009	4.15%
10/28/1988	8.798	8.80%	8.93%	1/15/2009	4.14%
10/27/1988	8.827	8.83%	8.93%	1/16/2009	4.14%
10/26/1988	8.909	8.91%	8.93%	1/19/2009	4.13%
10/25/1988	8.926	8.93%	8.93%	1/20/2009	4.12%
10/24/1988	8.92	8.92%	8.93%	1/21/2009	4.12%
10/21/1988	8.879	8.88%	8.93%	1/22/2009	4.11%
10/20/1988	8.838	8.84%	8.93%	1/23/2009	4.10%
10/19/1988	8.891	8.89%	8.93%	1/26/2009	4.10%
10/18/1988	8.855	8.86%	8.93%	1/27/2009	4.09%
10/17/1988	8.867	8.87%	8.93%	1/28/2009	4.09%
10/14/1988	8.897	8.90%	8.93%	1/29/2009	4.08%
10/13/1988	8.92	8.92%	8.93%	1/30/2009	4.08%
10/12/1988	8.902	8.90%	8.93%	2/2/2009	4.07%
10/11/1988	8.849	8.85%	8.93%	2/3/2009	4.07%
10/7/1988	8.797	8.80%	8.94%	2/4/2009	4.06%

10/6/1988	8.944	8.94%	8.94%	2/5/2009	4.06%
10/5/1988	8.95	8.95%	8.94%	2/6/2009	4.05%
10/4/1988	8.955	8.96%	8.94%	2/9/2009	4.05%
10/3/1988	8.952	8.95%	8.94%	2/10/2009	4.04%
9/30/1988	9.051	9.05%	8.94%	2/11/2009	4.04%
9/29/1988	9.051	9.05%	8.94%	2/12/2009	4.03%
9/28/1988	9.1	9.10%	8.94%	2/13/2009	4.03%
9/27/1988	9.125	9.13%	8.94%	2/16/2009	4.02%
9/26/1988	9.076	9.08%	8.95%	2/17/2009	4.02%
9/23/1988	9.045	9.05%	8.95%	2/18/2009	4.01%
9/22/1988	9.039	9.04%	8.95%	2/19/2009	4.01%
9/21/1988	9.009	9.01%	8.95%	2/20/2009	4.00%
9/20/1988	9.033	9.03%	8.95%	2/23/2009	4.00%
9/19/1988	9.063	9.06%	8.95%	2/24/2009	3.99%
9/16/1988	9.003	9.00%	8.95%	2/25/2009	3.99%
9/15/1988	8.991	8.99%	8.95%	2/26/2009	3.98%
9/14/1988	8.967	8.97%	8.95%	2/27/2009	3.98%
9/13/1988	8.997	9.00%	8.95%	3/2/2009	3.97%
9/12/1988	9.033	9.03%	8.95%	3/3/2009	3.97%
9/9/1988	8.979	8.98%	8.95%	3/4/2009	3.96%
9/8/1988	9.027	9.03%	8.95%	3/5/2009	3.96%
9/7/1988	9.057	9.06%	8.95%	3/6/2009	3.95%
9/6/1988	9.051	9.05%	8.95%	3/9/2009	3.95%
9/2/1988	9.045	9.05%	8.95%	3/10/2009	3.94%
9/1/1988	9.298	9.30%	8.95%	3/11/2009	3.94%
8/31/1988	9.298	9.30%	8.94%	3/12/2009	3.93%
8/30/1988	9.324	9.32%	8.94%	3/13/2009	3.93%
8/29/1988	9.336	9.34%	8.94%	3/16/2009	3.92%
8/26/1988	9.426	9.43%	8.94%	3/17/2009	3.92%
8/25/1988	9.446	9.45%	8.93%	3/18/2009	3.91%
8/24/1988	9.4	9.40%	8.93%	3/19/2009	3.91%
8/23/1988	9.375	9.38%	8.93%	3/20/2009	3.90%
8/22/1988	9.446	9.45%	8.93%	3/23/2009	3.89%
8/19/1988	9.394	9.39%	8.93%	3/24/2009	3.89%
8/18/1988	9.4	9.40%	8.92%	3/25/2009	3.88%
8/17/1988	9.413	9.41%	8.92%	3/26/2009	3.88%
8/16/1988	9.4	9.40%	8.92%	3/27/2009	3.87%
8/15/1988	9.433	9.43%	8.92%	3/30/2009	3.87%
8/12/1988	9.42	9.42%	8.92%	3/31/2009	3.86%
8/11/1988	9.381	9.38%	8.91%	4/1/2009	3.86%
8/10/1988	9.362	9.36%	8.91%	4/2/2009	3.85%
8/9/1988	9.192	9.19%	8.91%	4/3/2009	3.85%
8/8/1988	9.1	9.10%	8.91%	4/6/2009	3.84%
8/5/1988	9.124	9.12%	8.92%	4/7/2009	3.84%
8/4/1988	9.039	9.04%	8.92%	4/8/2009	3.83%
8/3/1988	9.075	9.08%	8.93%	4/9/2009	3.83%
8/2/1988	9.063	9.06%	8.93%	4/10/2009	3.83%

8/1/1988	9.161	9.16%	8.94%	4/13/2009	3.82%
7/29/1988	9.207	9.21%	8.94%	4/14/2009	3.82%
7/28/1988	9.254	9.25%	8.95%	4/15/2009	3.82%
7/27/1988	9.242	9.24%	8.95%	4/16/2009	3.81%
7/26/1988	9.18	9.18%	8.95%	4/17/2009	3.81%
7/25/1988	9.155	9.16%	8.95%	4/20/2009	3.80%
7/22/1988	9.195	9.20%	8.96%	4/21/2009	3.80%
7/21/1988	9.254	9.25%	8.96%	4/22/2009	3.80%
7/20/1988	9.226	9.23%	8.96%	4/23/2009	3.79%
7/19/1988	9.198	9.20%	8.97%	4/24/2009	3.79%
7/18/1988	9.229	9.23%	8.97%	4/27/2009	3.79%
7/15/1988	9.14	9.14%	8.97%	4/28/2009	3.78%
7/14/1988	9.167	9.17%	8.97%	4/29/2009	3.78%
7/13/1988	9.174	9.17%	8.97%	4/30/2009	3.78%
7/12/1988	9.124	9.12%	8.98%	5/1/2009	3.77%
7/11/1988	9.051	9.05%	8.98%	5/4/2009	3.77%
7/8/1988	9.091	9.09%	8.98%	5/5/2009	3.77%
7/7/1988	8.997	9.00%	8.98%	5/6/2009	3.76%
7/6/1988	8.982	8.98%	8.99%	5/7/2009	3.76%
7/5/1988	8.867	8.87%	8.99%	5/8/2009	3.76%
7/1/1988	8.832	8.83%	8.99%	5/11/2009	3.76%
6/30/1988	8.914	8.91%	9.00%	5/12/2009	3.76%
6/29/1988	8.856	8.86%	9.00%	5/13/2009	3.75%
6/28/1988	8.956	8.96%	9.00%	5/14/2009	3.75%
6/27/1988	8.85	8.85%	9.01%	5/15/2009	3.75%
6/24/1988	8.908	8.91%	9.01%	5/18/2009	3.75%
6/23/1988	8.914	8.91%	9.01%	5/19/2009	3.75%
6/22/1988	9.088	9.09%	9.02%	5/20/2009	3.74%
6/21/1988	9.088	9.09%	9.02%	5/21/2009	3.74%
6/20/1988	9.094	9.09%	9.02%	5/22/2009	3.74%
6/17/1988	8.98	8.98%	9.02%	5/25/2009	3.74%
6/16/1988	8.827	8.83%	9.02%	5/26/2009	3.74%
6/15/1988	8.809	8.81%	9.02%	5/27/2009	3.74%
6/14/1988	9.016	9.02%	9.02%	5/28/2009	3.74%
6/13/1988	9.034	9.03%	9.02%	5/29/2009	3.74%
6/10/1988	9.046	9.05%	9.02%	6/1/2009	3.74%
6/9/1988	9.016	9.02%	9.02%	6/2/2009	3.74%
6/8/1988	9.113	9.11%	9.02%	6/3/2009	3.74%
6/7/1988	9.052	9.05%	9.02%	6/4/2009	3.74%
6/6/1988	9.046	9.05%	9.02%	6/5/2009	3.75%
6/3/1988	9.15	9.15%	9.01%	6/8/2009	3.75%
6/2/1988	9.077	9.08%	9.01%	6/9/2009	3.75%
5/31/1988	9.237	9.24%	9.01%	6/10/2009	3.75%
5/27/1988	9.322	9.32%	9.01%	6/11/2009	3.75%
5/26/1988	9.325	9.33%	9.01%	6/12/2009	3.75%
5/25/1988	9.294	9.29%	9.01%	6/15/2009	3.76%
5/24/1988	9.332	9.33%	9.00%	6/16/2009	3.76%

5/23/1988	9.351	9.35%	9.00%	6/17/2009	3.76%
5/20/1988	9.338	9.34%	9.00%	6/18/2009	3.76%
5/19/1988	9.275	9.28%	9.00%	6/19/2009	3.76%
5/18/1988	9.3	9.30%	9.00%	6/22/2009	3.76%
5/17/1988	9.213	9.21%	8.99%	6/23/2009	3.77%
5/16/1988	9.12	9.12%	8.99%	6/24/2009	3.77%
5/13/1988	9.096	9.10%	8.99%	6/25/2009	3.77%
5/12/1988	9.215	9.22%	8.99%	6/26/2009	3.77%
5/11/1988	9.202	9.20%	8.99%	6/29/2009	3.77%
5/10/1988	9.183	9.18%	8.99%	6/30/2009	3.77%
5/9/1988	9.158	9.16%	8.98%	7/1/2009	3.77%
5/6/1988	9.152	9.15%	8.98%	7/2/2009	3.77%
5/5/1988	9.089	9.09%	8.98%	7/3/2009	3.77%
5/4/1988	9.108	9.11%	8.98%	7/6/2009	3.77%
5/3/1988	9.089	9.09%	8.97%	7/7/2009	3.77%
5/2/1988	9.12	9.12%	8.97%	7/8/2009	3.77%
4/29/1988	9.095	9.10%	8.97%	7/9/2009	3.77%
4/28/1988	9.095	9.10%	8.97%	7/10/2009	3.77%
4/27/1988	9.014	9.01%	8.96%	7/13/2009	3.77%
4/26/1988	9.002	9.00%	8.96%	7/14/2009	3.77%
4/25/1988	8.996	9.00%	8.96%	7/15/2009	3.77%
4/22/1988	8.993	8.99%	8.95%	7/16/2009	3.77%
4/21/1988	9.027	9.03%	8.95%	7/17/2009	3.78%
4/20/1988	9.008	9.01%	8.95%	7/20/2009	3.78%
4/19/1988	9.033	9.03%	8.95%	7/21/2009	3.78%
4/18/1988	9.014	9.01%	8.94%	7/22/2009	3.78%
4/15/1988	8.941	8.94%	8.94%	7/23/2009	3.78%
4/14/1988	8.874	8.87%	8.94%	7/24/2009	3.78%
4/13/1988	8.732	8.73%	8.94%	7/27/2009	3.78%
4/12/1988	8.75	8.75%	8.93%	7/28/2009	3.79%
4/11/1988	8.773	8.77%	8.93%	7/29/2009	3.79%
4/8/1988	8.679	8.68%	8.93%	7/30/2009	3.79%
4/7/1988	8.779	8.78%	8.93%	7/31/2009	3.79%
4/6/1988	8.761	8.76%	8.93%	8/3/2009	3.79%
4/5/1988	8.845	8.85%	8.93%	8/4/2009	3.79%
4/4/1988	8.857	8.86%	8.92%	8/5/2009	3.80%
3/31/1988	8.756	8.76%	8.92%	8/6/2009	3.80%
3/30/1988	8.762	8.76%	8.92%	8/7/2009	3.80%
3/29/1988	8.75	8.75%	8.92%	8/10/2009	3.80%
3/28/1988	8.833	8.83%	8.92%	8/11/2009	3.80%
3/25/1988	8.668	8.67%	8.92%	8/12/2009	3.80%
3/24/1988	8.727	8.73%	8.92%	8/13/2009	3.80%
3/23/1988	8.738	8.74%	8.92%	8/14/2009	3.80%
3/22/1988	8.703	8.70%	8.92%	8/17/2009	3.81%
3/21/1988	8.697	8.70%	8.92%	8/18/2009	3.81%
3/18/1988	8.671	8.67%	8.92%	8/19/2009	3.81%
3/17/1988	8.537	8.54%	8.92%	8/20/2009	3.81%

3/16/1988	8.611	8.61%	8.92%	8/21/2009	3.81%
3/15/1988	8.514	8.51%	8.92%	8/24/2009	3.81%
3/14/1988	8.509	8.51%	8.92%	8/25/2009	3.81%
3/11/1988	8.503	8.50%	8.92%	8/26/2009	3.81%
3/10/1988	8.56	8.56%	8.93%	8/27/2009	3.81%
3/9/1988	8.515	8.52%	8.93%	8/28/2009	3.82%
3/8/1988	8.52	8.52%	8.93%	8/31/2009	3.82%
3/7/1988	8.512	8.51%	8.93%	9/1/2009	3.82%
3/4/1988	8.47	8.47%	8.94%	9/2/2009	3.82%
3/3/1988	8.31	8.31%	8.94%	9/3/2009	3.83%
3/2/1988	8.31	8.31%	8.94%	9/4/2009	3.83%
3/1/1988	8.343	8.34%	8.94%	9/7/2009	3.84%
2/29/1988	8.338	8.34%	8.94%	9/8/2009	3.84%
2/26/1988	8.354	8.35%	8.95%	9/9/2009	3.85%
2/25/1988	8.42	8.42%	8.95%	9/10/2009	3.85%
2/24/1988	8.373	8.37%	8.95%	9/11/2009	3.86%
2/23/1988	8.349	8.35%	8.95%	9/14/2009	3.86%
2/22/1988	8.418	8.42%	8.95%	9/15/2009	3.87%
2/19/1988	8.446	8.45%	8.95%	9/16/2009	3.88%
2/18/1988	8.448	8.45%	8.95%	9/17/2009	3.88%
2/17/1988	8.479	8.48%	8.95%	9/18/2009	3.89%
2/16/1988	8.462	8.46%	8.95%	9/21/2009	3.89%
2/12/1988	8.421	8.42%	8.95%	9/22/2009	3.90%
2/11/1988	8.344	8.34%	8.96%	9/23/2009	3.91%
2/10/1988	8.289	8.29%	8.96%	9/24/2009	3.92%
2/9/1988	8.333	8.33%	8.96%	9/25/2009	3.92%
2/8/1988	8.363	8.36%	8.96%	9/28/2009	3.93%
2/5/1988	8.286	8.29%	8.96%	9/29/2009	3.94%
2/4/1988	8.437	8.44%	8.96%	9/30/2009	3.95%
2/3/1988	8.387	8.39%	8.96%	10/1/2009	3.95%
2/2/1988	8.322	8.32%	8.96%	10/2/2009	3.96%
2/1/1988	8.426	8.43%	8.96%	10/5/2009	3.97%
1/29/1988	8.415	8.42%	8.96%	10/6/2009	3.97%
1/28/1988	8.493	8.49%	8.96%	10/7/2009	3.98%
1/27/1988	8.532	8.53%	8.95%	10/8/2009	3.99%
1/26/1988	8.704	8.70%	8.95%	10/9/2009	3.99%
1/25/1988	8.617	8.62%	8.95%	10/12/2009	4.00%
1/22/1988	8.652	8.65%	8.94%	10/13/2009	4.01%
1/21/1988	8.698	8.70%	8.94%	10/14/2009	4.01%
1/20/1988	8.774	8.77%	8.94%	10/15/2009	4.02%
1/19/1988	8.798	8.80%	8.93%	10/16/2009	4.02%
1/15/1988	8.762	8.76%	8.93%	10/19/2009	4.03%
1/14/1988	9.021	9.02%	8.92%	10/20/2009	4.04%
1/13/1988	9.033	9.03%	8.91%	10/21/2009	4.04%
1/12/1988	9.102	9.10%	8.91%	10/22/2009	4.05%
1/11/1988	9.089	9.09%	8.90%	10/23/2009	4.06%
1/8/1988	9.089	9.09%	8.89%	10/26/2009	4.06%

1/7/1988	8.947	8.95%	8.88%	10/27/2009	4.07%
1/6/1988	8.996	9.00%	8.88%	10/28/2009	4.08%
1/5/1988	8.851	8.85%	8.87%	10/29/2009	4.08%
1/4/1988	8.923	8.92%	8.86%	10/30/2009	4.09%
12/31/1987	8.978	8.98%	8.86%	11/2/2009	4.09%
12/30/1987	8.887	8.89%	8.85%	11/3/2009	4.10%
12/29/1987	8.917	8.92%	8.84%	11/4/2009	4.10%
12/28/1987	8.99	8.99%	8.83%	11/5/2009	4.11%
12/24/1987	8.911	8.91%	8.83%	11/6/2009	4.11%
12/23/1987	8.905	8.91%	8.82%	11/9/2009	4.11%
12/22/1987	9.045	9.05%	8.81%	11/10/2009	4.12%
12/21/1987	9.008	9.01%	8.81%	11/11/2009	4.12%
12/18/1987	8.917	8.92%	8.80%	11/12/2009	4.13%
12/17/1987	9.142	9.14%	8.79%	11/13/2009	4.13%
12/16/1987	9.132	9.13%	8.78%	11/16/2009	4.13%
12/15/1987	9.202	9.20%	8.77%	11/17/2009	4.14%
12/14/1987	9.376	9.38%	8.76%	11/18/2009	4.14%
12/11/1987	9.455	9.46%	8.76%	11/19/2009	4.14%
12/10/1987	9.383	9.38%	8.75%	11/20/2009	4.15%
12/9/1987	9.202	9.20%	8.74%	11/23/2009	4.15%
12/8/1987	9.221	9.22%	8.73%	11/24/2009	4.15%
12/7/1987	9.214	9.21%	8.72%	11/25/2009	4.16%
12/4/1987	9.12	9.12%	8.71%	11/26/2009	4.16%
12/3/1987	9.045	9.05%	8.70%	11/27/2009	4.16%
12/2/1987	9.129	9.13%	8.70%	11/30/2009	4.17%
12/1/1987	9.132	9.13%	8.69%	12/1/2009	4.17%
11/30/1987	9.101	9.10%	8.68%	12/2/2009	4.17%
11/27/1987	9.157	9.16%	8.67%	12/3/2009	4.18%
11/25/1987	9.063	9.06%	8.67%	12/4/2009	4.18%
11/24/1987	9.002	9.00%	8.66%	12/7/2009	4.18%
11/23/1987	8.892	8.89%	8.65%	12/8/2009	4.19%
11/20/1987	8.844	8.84%	8.64%	12/9/2009	4.19%
11/19/1987	8.922	8.92%	8.64%	12/10/2009	4.20%
11/18/1987	8.931	8.93%	8.63%	12/11/2009	4.20%
11/17/1987	8.928	8.93%	8.62%	12/14/2009	4.21%
11/16/1987	8.898	8.90%	8.61%	12/15/2009	4.21%
11/13/1987	8.938	8.94%	8.61%	12/16/2009	4.21%
11/12/1987	8.862	8.86%	8.60%	12/17/2009	4.22%
11/10/1987	8.874	8.87%	8.59%	12/18/2009	4.22%
11/9/1987	8.826	8.83%	8.59%	12/21/2009	4.23%
11/6/1987	8.838	8.84%	8.58%	12/22/2009	4.23%
11/5/1987	8.779	8.78%	8.57%	12/23/2009	4.24%
11/4/1987	8.941	8.94%	8.56%	12/24/2009	4.24%
11/3/1987	9.026	9.03%	8.56%	12/25/2009	4.25%
11/2/1987	9.119	9.12%	8.55%	12/28/2009	4.25%
10/30/1987	9.032	9.03%	8.54%	12/29/2009	4.26%
10/29/1987	9.008	9.01%	8.53%	12/30/2009	4.26%

10/28/1987	9.138	9.14%	8.52%	12/31/2009	4.27%
10/27/1987	9.063	9.06%	8.51%	1/1/2010	4.27%
10/26/1987	8.892	8.89%	8.50%	1/4/2010	4.28%
10/23/1987	9.094	9.09%	8.50%	1/5/2010	4.28%
10/22/1987	9.088	9.09%	8.49%	1/6/2010	4.29%
10/21/1987	9.448	9.45%	8.48%	1/7/2010	4.29%
10/20/1987	9.481	9.48%	8.47%	1/8/2010	4.30%
10/19/1987	9.811	9.81%	8.46%	1/11/2010	4.30%
10/16/1987	10.179	10.18%	8.45%	1/12/2010	4.31%
10/15/1987	10.22	10.22%	8.43%	1/13/2010	4.31%
10/14/1987	10.16	10.16%	8.42%	1/14/2010	4.32%
10/13/1987	9.889	9.89%	8.40%	1/15/2010	4.32%
10/9/1987	9.932	9.93%	8.39%	1/18/2010	4.33%
10/8/1987	9.857	9.86%	8.38%	1/19/2010	4.33%
10/7/1987	9.797	9.80%	8.37%	1/20/2010	4.33%
10/6/1987	9.765	9.77%	8.35%	1/21/2010	4.34%
10/5/1987	9.793	9.79%	8.34%	1/22/2010	4.34%
10/2/1987	9.692	9.69%	8.33%	1/25/2010	4.35%
10/1/1987	9.772	9.77%	8.32%	1/26/2010	4.35%
9/30/1987	9.744	9.74%	8.31%	1/27/2010	4.35%
9/29/1987	9.804	9.80%	8.29%	1/28/2010	4.36%
9/28/1987	9.664	9.66%	8.28%	1/29/2010	4.36%
9/25/1987	9.664	9.66%	8.27%	2/1/2010	4.36%
9/24/1987	9.685	9.69%	8.26%	2/2/2010	4.37%
9/23/1987	9.542	9.54%	8.25%	2/3/2010	4.37%
9/22/1987	9.518	9.52%	8.24%	2/4/2010	4.37%
9/21/1987	9.613	9.61%	8.23%	2/5/2010	4.38%
9/18/1987	9.556	9.56%	8.21%	2/8/2010	4.38%
9/17/1987	9.542	9.54%	8.20%	2/9/2010	4.38%
9/16/1987	9.672	9.67%	8.19%	2/10/2010	4.38%
9/15/1987	9.672	9.67%	8.18%	2/11/2010	4.38%
9/14/1987	9.499	9.50%	8.17%	2/12/2010	4.39%
9/11/1987	9.495	9.50%	8.16%	2/15/2010	4.39%
9/10/1987	9.556	9.56%	8.15%	2/16/2010	4.39%
9/9/1987	9.624	9.62%	8.14%	2/17/2010	4.39%
9/8/1987	9.641	9.64%	8.13%	2/18/2010	4.40%
9/4/1987	9.459	9.46%	8.12%	2/19/2010	4.40%
9/3/1987	9.436	9.44%	8.11%	2/22/2010	4.40%
9/2/1987	9.436	9.44%	8.10%	2/23/2010	4.41%
9/1/1987	9.266	9.27%	8.09%	2/24/2010	4.41%
8/31/1987	9.152	9.15%	8.08%	2/25/2010	4.41%
8/28/1987	9.177	9.18%	8.07%	2/26/2010	4.41%
8/27/1987	9.121	9.12%	8.06%	3/1/2010	4.41%
8/26/1987	8.973	8.97%	8.06%	3/2/2010	4.41%
8/25/1987	8.93	8.93%	8.05%	3/3/2010	4.41%
8/24/1987	8.979	8.98%	8.04%	3/4/2010	4.41%
8/21/1987	8.964	8.96%	8.03%	3/5/2010	4.41%

8/20/1987	8.924	8.92%	8.03%	3/8/2010	4.41%
8/19/1987	9.003	9.00%	8.02%	3/9/2010	4.41%
8/18/1987	8.924	8.92%	8.01%	3/10/2010	4.42%
8/17/1987	8.793	8.79%	8.01%	3/11/2010	4.42%
8/14/1987	8.74	8.74%	8.00%	3/12/2010	4.42%
8/13/1987	8.77	8.77%	8.00%	3/15/2010	4.42%
8/12/1987	8.942	8.94%	7.99%	3/16/2010	4.42%
8/11/1987	8.955	8.96%	7.99%	3/17/2010	4.41%
8/10/1987	8.936	8.94%	7.98%	3/18/2010	4.41%
8/7/1987	8.9	8.90%	7.98%	3/19/2010	4.41%
8/6/1987	8.936	8.94%	7.97%	3/22/2010	4.41%
8/5/1987	8.936	8.94%	7.96%	3/23/2010	4.41%
8/4/1987	9.02	9.02%	7.96%	3/24/2010	4.42%
8/3/1987	9.013	9.01%	7.95%	3/25/2010	4.42%
7/31/1987	8.896	8.90%	7.95%	3/26/2010	4.42%
7/30/1987	8.833	8.83%	7.94%	3/29/2010	4.42%
7/29/1987	8.809	8.81%	7.93%	3/30/2010	4.42%
7/28/1987	8.86	8.86%	7.93%	3/31/2010	4.42%
7/27/1987	8.815	8.82%	7.92%	4/1/2010	4.42%
7/24/1987	8.83	8.83%	7.92%	4/2/2010	4.43%
7/23/1987	8.776	8.78%	7.91%	4/5/2010	4.43%
7/22/1987	8.785	8.79%	7.90%	4/6/2010	4.43%
7/21/1987	8.714	8.71%	7.90%	4/7/2010	4.43%
7/20/1987	8.618	8.62%	7.89%	4/8/2010	4.44%
7/17/1987	8.554	8.55%	7.89%	4/9/2010	4.44%
7/16/1987	8.586	8.59%	7.88%	4/12/2010	4.44%
7/15/1987	8.603	8.60%	7.88%	4/13/2010	4.44%
7/14/1987	8.5	8.50%	7.87%	4/14/2010	4.45%
7/13/1987	8.535	8.54%	7.87%	4/15/2010	4.45%
7/10/1987	8.458	8.46%	7.86%	4/16/2010	4.45%
7/9/1987	8.512	8.51%	7.86%	4/19/2010	4.45%
7/8/1987	8.447	8.45%	7.86%	4/20/2010	4.45%
7/7/1987	8.377	8.38%	7.85%	4/21/2010	4.45%
7/6/1987	8.425	8.43%	7.85%	4/22/2010	4.45%
7/2/1987	8.43	8.43%	7.85%	4/23/2010	4.46%
7/1/1987	8.478	8.48%	7.84%	4/26/2010	4.46%
6/30/1987	8.492	8.49%	7.84%	4/27/2010	4.46%
6/29/1987	8.473	8.47%	7.83%	4/28/2010	4.46%
6/26/1987	8.484	8.48%	7.83%	4/29/2010	4.46%
6/25/1987	8.419	8.42%	7.82%	4/30/2010	4.46%
6/24/1987	8.445	8.45%	7.82%	5/3/2010	4.46%
6/23/1987	8.411	8.41%	7.81%	5/4/2010	4.46%
6/22/1987	8.4	8.40%	7.81%	5/5/2010	4.46%
6/19/1987	8.476	8.48%	7.80%	5/6/2010	4.46%
6/18/1987	8.481	8.48%	7.80%	5/7/2010	4.46%
6/17/1987	8.386	8.39%	7.79%	5/10/2010	4.46%
6/16/1987	8.448	8.45%	7.79%	5/11/2010	4.46%

6/15/1987	8.439	8.44%	7.78%	5/12/2010	4.45%
6/12/1987	8.487	8.49%	7.77%	5/13/2010	4.45%
6/11/1987	8.671	8.67%	7.77%	5/14/2010	4.45%
6/10/1987	8.73	8.73%	7.76%	5/17/2010	4.45%
6/9/1987	8.73	8.73%	7.75%	5/18/2010	4.45%
6/8/1987	8.692	8.69%	7.74%	5/19/2010	4.45%
6/5/1987	8.645	8.65%	7.74%	5/20/2010	4.45%
6/4/1987	8.727	8.73%	7.73%	5/21/2010	4.45%
6/3/1987	8.76	8.76%	7.72%	5/24/2010	4.44%
6/2/1987	8.925	8.93%	7.72%	5/25/2010	4.44%
6/1/1987	8.605	8.61%	7.71%	5/26/2010	4.44%
5/29/1987	8.636	8.64%	7.70%	5/27/2010	4.44%
5/28/1987	8.71	8.71%	7.70%	5/28/2010	4.44%
5/27/1987	8.73	8.73%	7.69%	5/31/2010	4.44%
5/26/1987	8.657	8.66%	7.69%	6/1/2010	4.44%
5/22/1987	8.904	8.90%	7.68%	6/2/2010	4.44%
5/21/1987	9.043	9.04%	7.67%	6/3/2010	4.44%
5/20/1987	9.062	9.06%	7.66%	6/4/2010	4.44%
5/19/1987	9.074	9.07%	7.66%	6/7/2010	4.44%
5/18/1987	8.886	8.89%	7.65%	6/8/2010	4.44%
5/15/1987	8.908	8.91%	7.64%	6/9/2010	4.44%
5/14/1987	8.731	8.73%	7.63%	6/10/2010	4.44%
5/13/1987	8.699	8.70%	7.63%	6/11/2010	4.44%
5/12/1987	8.696	8.70%	7.62%	6/14/2010	4.44%
5/11/1987	8.776	8.78%	7.61%	6/15/2010	4.44%
5/8/1987	8.586	8.59%	7.60%	6/16/2010	4.44%
5/7/1987	8.693	8.69%	7.60%	6/17/2010	4.44%
5/6/1987	8.729	8.73%	7.59%	6/18/2010	4.44%
5/5/1987	8.65	8.65%	7.58%	6/21/2010	4.44%
5/4/1987	8.689	8.69%	7.57%	6/22/2010	4.44%
5/1/1987	8.578	8.58%	7.57%	6/23/2010	4.44%
4/30/1987	8.437	8.44%	7.56%	6/24/2010	4.44%
4/29/1987	8.686	8.69%	7.55%	6/25/2010	4.43%
4/28/1987	8.478	8.48%	7.55%	6/28/2010	4.43%
4/27/1987	8.607	8.61%	7.54%	6/29/2010	4.43%
4/24/1987	8.682	8.68%	7.53%	6/30/2010	4.43%
4/23/1987	8.506	8.51%	7.52%	7/1/2010	4.43%
4/22/1987	8.494	8.49%	7.52%	7/2/2010	4.43%
4/21/1987	8.318	8.32%	7.51%	7/5/2010	4.43%
4/20/1987	8.386	8.39%	7.51%	7/6/2010	4.43%
4/16/1987	8.196	8.20%	7.50%	7/7/2010	4.43%
4/15/1987	8.281	8.28%	7.50%	7/8/2010	4.43%
4/14/1987	8.383	8.38%	7.49%	7/9/2010	4.43%
4/13/1987	8.358	8.36%	7.49%	7/12/2010	4.43%
4/10/1987	8.177	8.18%	7.48%	7/13/2010	4.43%
4/9/1987	8.07	8.07%	7.48%	7/14/2010	4.43%
4/8/1987	7.885	7.89%	7.48%	7/15/2010	4.43%

4/7/1987	7.936	7.94%	7.47%	7/16/2010	4.43%
4/6/1987	7.834	7.83%	7.47%	7/19/2010	4.42%
4/3/1987	7.851	7.85%	7.47%	7/20/2010	4.42%
4/2/1987	7.936	7.94%	7.47%	7/21/2010	4.42%
4/1/1987	7.859	7.86%	7.47%	7/22/2010	4.42%
3/31/1987	7.913	7.91%	7.46%	7/23/2010	4.42%
3/30/1987	7.836	7.84%	7.46%	7/26/2010	4.42%
3/27/1987	7.651	7.65%	7.46%	7/27/2010	4.42%
3/26/1987	7.549	7.55%	7.46%	7/28/2010	4.42%
3/25/1987	7.567	7.57%	7.47%	7/29/2010	4.42%
3/24/1987	7.559	7.56%	7.47%	7/30/2010	4.41%
3/23/1987	7.551	7.55%	7.47%	8/2/2010	4.41%
3/20/1987	7.517	7.52%	7.47%	8/3/2010	4.41%
3/19/1987	7.509	7.51%	7.47%	8/4/2010	4.41%
3/18/1987	7.503	7.50%	7.47%	8/5/2010	4.41%
3/17/1987	7.495	7.50%	7.47%	8/6/2010	4.41%
3/16/1987	7.517	7.52%	7.47%	8/9/2010	4.41%
3/13/1987	7.49	7.49%	7.47%	8/10/2010	4.41%
3/12/1987	7.517	7.52%	7.47%	8/11/2010	4.40%
3/11/1987	7.519	7.52%	7.47%	8/12/2010	4.40%
3/10/1987	7.522	7.52%	7.47%	8/13/2010	4.40%
3/9/1987	7.506	7.51%	7.47%	8/16/2010	4.39%
3/6/1987	7.514	7.51%	7.47%	8/17/2010	4.39%
3/5/1987	7.443	7.44%	7.47%	8/18/2010	4.39%
3/4/1987	7.425	7.43%	7.47%	8/19/2010	4.38%
3/3/1987	7.482	7.48%	7.47%	8/20/2010	4.38%
3/2/1987	7.453	7.45%	7.47%	8/23/2010	4.38%
2/27/1987	7.459	7.46%	7.47%	8/24/2010	4.37%
2/26/1987	7.49	7.49%	7.47%	8/25/2010	4.37%
2/25/1987	7.519	7.52%	7.47%	8/26/2010	4.37%
2/24/1987	7.49	7.49%	7.47%	8/27/2010	4.36%
2/23/1987	7.522	7.52%	7.47%	8/30/2010	4.36%
2/20/1987	7.554	7.55%	7.47%	8/31/2010	4.36%
2/19/1987	7.538	7.54%	7.47%	9/1/2010	4.35%
2/18/1987	7.58	7.58%	7.47%	9/2/2010	4.35%
2/17/1987	7.596	7.60%	7.47%	9/3/2010	4.35%
2/13/1987	7.58	7.58%	7.47%	9/6/2010	4.35%
2/12/1987	7.556	7.56%	7.47%	9/7/2010	4.34%
2/11/1987	7.604	7.60%	7.47%	9/8/2010	4.34%
2/10/1987	7.602	7.60%	7.47%	9/9/2010	4.34%
2/9/1987	7.516	7.52%	7.47%	9/10/2010	4.34%
2/6/1987	7.459	7.46%	7.47%	9/13/2010	4.33%
2/5/1987	7.417	7.42%	7.47%	9/14/2010	4.33%
2/4/1987	7.508	7.51%	7.46%	9/15/2010	4.33%
2/3/1987	7.516	7.52%	7.46%	9/16/2010	4.33%
2/2/1987	7.501	7.50%	7.46%	9/17/2010	4.32%
1/30/1987	7.474	7.47%	7.46%	9/20/2010	4.32%

1/29/1987	7.443	7.44%	7.46%	9/21/2010	4.32%
1/28/1987	7.459	7.46%	7.46%	9/22/2010	4.31%
1/27/1987	7.477	7.48%	7.46%	9/23/2010	4.31%
1/26/1987	7.472	7.47%	7.46%	9/24/2010	4.30%
1/23/1987	7.44	7.44%	7.46%	9/27/2010	4.30%
1/22/1987	7.34	7.34%	7.46%	9/28/2010	4.30%
1/21/1987	7.322	7.32%	7.46%	9/29/2010	4.29%
1/20/1987	7.314	7.31%	7.46%	9/30/2010	4.29%
1/16/1987	7.33	7.33%	7.46%	10/1/2010	4.28%
1/15/1987	7.381	7.38%	7.46%	10/4/2010	4.28%
1/14/1987	7.399	7.40%	7.46%	10/5/2010	4.27%
1/13/1987	7.365	7.37%	7.46%	10/6/2010	4.27%
1/12/1987	7.335	7.34%	7.47%	10/7/2010	4.26%
1/9/1987	7.279	7.28%	7.47%	10/8/2010	4.26%
1/8/1987	7.322	7.32%	7.47%	10/11/2010	4.25%
1/7/1987	7.289	7.29%	7.48%	10/12/2010	4.25%
1/6/1987	7.35	7.35%	7.48%	10/13/2010	4.25%
1/5/1987	7.335	7.34%	7.48%	10/14/2010	4.24%
1/2/1987	7.397	7.40%	7.49%	10/15/2010	4.24%
12/31/1986	7.485	7.49%	7.49%	10/18/2010	4.23%
12/30/1986	7.443	7.44%	7.49%	10/19/2010	4.23%
12/29/1986	7.428	7.43%	7.49%	10/20/2010	4.23%
12/26/1986	7.333	7.33%	7.50%	10/21/2010	4.22%
12/24/1986	7.335	7.34%	7.50%	10/22/2010	4.22%
12/23/1986	7.343	7.34%	7.50%	10/25/2010	4.22%
12/22/1986	7.348	7.35%	7.51%	10/26/2010	4.21%
12/19/1986	7.363	7.36%	7.51%	10/27/2010	4.21%
12/18/1986	7.371	7.37%	7.51%	10/28/2010	4.21%
12/17/1986	7.376	7.38%	7.52%	10/29/2010	4.21%
12/16/1986	7.381	7.38%	7.52%	11/1/2010	4.20%
12/15/1986	7.402	7.40%	7.53%	11/2/2010	4.20%
12/12/1986	7.392	7.39%	7.53%	11/3/2010	4.20%
12/11/1986	7.356	7.36%	7.54%	11/4/2010	4.20%
12/10/1986	7.313	7.31%	7.55%	11/5/2010	4.19%
12/9/1986	7.335	7.34%	7.55%	11/8/2010	4.19%
12/8/1986	7.318	7.32%	7.56%	11/9/2010	4.19%
12/5/1986	7.361	7.36%	7.57%	11/10/2010	4.19%
12/4/1986	7.26	7.26%	7.58%	11/11/2010	4.19%
12/3/1986	7.318	7.32%	7.58%	11/12/2010	4.18%
12/2/1986	7.348	7.35%	7.59%	11/15/2010	4.18%
12/1/1986	7.4	7.40%	7.60%	11/16/2010	4.18%
11/28/1986	7.403	7.40%	7.61%	11/17/2010	4.18%
11/26/1986	7.41	7.41%	7.62%	11/18/2010	4.18%
11/25/1986	7.441	7.44%	7.63%	11/19/2010	4.18%
11/24/1986	7.382	7.38%	7.64%	11/22/2010	4.18%
11/21/1986	7.434	7.43%	7.65%	11/23/2010	4.17%
11/20/1986	7.483	7.48%	7.66%	11/24/2010	4.17%

11/19/1986	7.426	7.43%	7.66%	11/25/2010	4.17%
11/18/1986	7.512	7.51%	7.67%	11/26/2010	4.17%
11/17/1986	7.476	7.48%	7.68%	11/29/2010	4.16%
11/14/1986	7.52	7.52%	7.69%	11/30/2010	4.16%
11/13/1986	7.584	7.58%	7.70%	12/1/2010	4.16%
11/12/1986	7.587	7.59%	7.71%	12/2/2010	4.16%
11/10/1986	7.614	7.61%	7.72%	12/3/2010	4.16%
11/7/1986	7.662	7.66%	7.73%	12/6/2010	4.15%
11/6/1986	7.544	7.54%	7.74%	12/7/2010	4.15%
11/5/1986	7.588	7.59%	7.75%	12/8/2010	4.15%
11/4/1986	7.574	7.57%	7.76%	12/9/2010	4.15%
11/3/1986	7.568	7.57%	7.76%	12/10/2010	4.15%
10/31/1986	7.607	7.61%	7.77%	12/13/2010	4.15%
10/30/1986	7.598	7.60%	7.78%	12/14/2010	4.15%
10/29/1986	7.676	7.68%	7.79%	12/15/2010	4.15%
10/28/1986	7.784	7.78%	7.80%	12/16/2010	4.15%
10/27/1986	7.718	7.72%	7.81%	12/17/2010	4.15%
10/24/1986	7.764	7.76%	7.82%	12/20/2010	4.15%
10/23/1986	7.718	7.72%	7.83%	12/21/2010	4.14%
10/22/1986	7.767	7.77%	7.83%	12/22/2010	4.14%
10/21/1986	7.821	7.82%	7.84%	12/23/2010	4.14%
10/20/1986	7.902	7.90%	7.85%	12/24/2010	4.14%
10/17/1986	7.832	7.83%	7.86%	12/27/2010	4.14%
10/16/1986	7.798	7.80%	7.86%	12/28/2010	4.14%
10/15/1986	7.752	7.75%	7.87%	12/29/2010	4.14%
10/14/1986	7.789	7.79%	7.88%	12/30/2010	4.14%
10/10/1986	7.659	7.66%	7.89%	12/31/2010	4.14%
10/9/1986	7.609	7.61%	7.89%	1/3/2011	4.13%
10/8/1986	7.614	7.61%	7.90%	1/4/2011	4.13%
10/7/1986	7.537	7.54%	7.91%	1/5/2011	4.13%
10/6/1986	7.526	7.53%	7.92%	1/6/2011	4.13%
10/3/1986	7.524	7.52%	7.93%	1/7/2011	4.13%
10/2/1986	7.625	7.63%	7.94%	1/10/2011	4.13%
10/1/1986	7.6	7.60%	7.95%	1/11/2011	4.13%
9/30/1986	7.592	7.59%	7.96%	1/12/2011	4.12%
9/29/1986	7.692	7.69%	7.97%	1/13/2011	4.12%
9/26/1986	7.631	7.63%	7.98%	1/14/2011	4.12%
9/25/1986	7.661	7.66%	7.99%	1/17/2011	4.12%
9/24/1986	7.631	7.63%	8.00%	1/18/2011	4.12%
9/23/1986	7.709	7.71%	8.01%	1/19/2011	4.12%
9/22/1986	7.777	7.78%	8.02%	1/20/2011	4.12%
9/19/1986	7.817	7.82%	8.03%	1/21/2011	4.12%
9/18/1986	7.737	7.74%	8.04%	1/24/2011	4.12%
9/17/1986	7.639	7.64%	8.05%	1/25/2011	4.12%
9/16/1986	7.658	7.66%	8.06%	1/26/2011	4.12%
9/15/1986	7.639	7.64%	8.08%	1/27/2011	4.12%
9/12/1986	7.675	7.68%	8.09%	1/28/2011	4.12%

9/11/1986	7.72	7.72%	8.10%	1/31/2011	4.12%
9/10/1986	7.545	7.55%	8.11%	2/1/2011	4.12%
9/9/1986	7.466	7.47%	8.12%	2/2/2011	4.12%
9/8/1986	7.603	7.60%	8.13%	2/3/2011	4.12%
9/5/1986	7.531	7.53%	8.15%	2/4/2011	4.12%
9/4/1986	7.418	7.42%	8.16%	2/7/2011	4.12%
9/3/1986	7.379	7.38%	8.17%	2/8/2011	4.12%
9/2/1986	7.323	7.32%	8.19%	2/9/2011	4.12%
8/29/1986	7.197	7.20%	8.20%	2/10/2011	4.12%
8/28/1986	7.246	7.25%	8.22%	2/11/2011	4.13%
8/26/1986	7.197	7.20%	8.23%	2/14/2011	4.13%
8/25/1986	7.225	7.23%	8.24%	2/15/2011	4.13%
8/22/1986	7.274	7.27%	8.26%	2/16/2011	4.13%
8/21/1986	7.194	7.19%	8.27%	2/17/2011	4.13%
8/20/1986	7.159	7.16%	8.29%	2/18/2011	4.13%
8/19/1986	7.169	7.17%	8.30%	2/21/2011	4.13%
8/18/1986	7.264	7.26%	8.32%	2/22/2011	4.14%
8/15/1986	7.287	7.29%	8.34%	2/23/2011	4.14%
8/14/1986	7.282	7.28%	8.35%	2/24/2011	4.14%
8/13/1986	7.266	7.27%	8.37%	2/25/2011	4.14%
8/12/1986	7.344	7.34%	8.38%	2/28/2011	4.14%
8/11/1986	7.339	7.34%	8.40%	3/1/2011	4.15%
8/8/1986	7.415	7.42%	8.41%	3/2/2011	4.15%
8/7/1986	7.526	7.53%	8.43%	3/3/2011	4.15%
8/6/1986	7.575	7.58%	8.44%	3/4/2011	4.15%
8/5/1986	7.509	7.51%	8.46%	3/7/2011	4.15%
8/4/1986	7.45	7.45%	8.47%	3/8/2011	4.16%
8/1/1986	7.445	7.45%	8.49%	3/9/2011	4.16%
7/31/1986	7.418	7.42%	8.50%	3/10/2011	4.16%
7/30/1986	7.466	7.47%	8.52%	3/11/2011	4.16%
7/29/1986	7.474	7.47%	8.54%	3/14/2011	4.16%
7/28/1986	7.566	7.57%	8.55%	3/15/2011	4.17%
7/25/1986	7.407	7.41%	8.57%	3/16/2011	4.17%
7/24/1986	7.386	7.39%	8.58%	3/17/2011	4.17%
7/23/1986	7.339	7.34%	8.60%	3/18/2011	4.17%
7/22/1986	7.269	7.27%	8.61%	3/21/2011	4.17%
7/21/1986	7.174	7.17%	8.63%	3/22/2011	4.17%
7/18/1986	7.184	7.18%	8.65%	3/23/2011	4.17%
7/17/1986	7.177	7.18%	8.66%	3/24/2011	4.18%
7/16/1986	7.174	7.17%	8.68%	3/25/2011	4.18%
7/15/1986	7.114	7.11%	8.70%	3/28/2011	4.18%
7/14/1986	7.136	7.14%	8.71%	3/29/2011	4.18%
7/11/1986	7.182	7.18%	8.73%	3/30/2011	4.18%
7/10/1986	7.126	7.13%	8.75%	3/31/2011	4.19%
7/9/1986	7.136	7.14%	8.77%	4/1/2011	4.19%
7/8/1986	7.22	7.22%	8.78%	4/4/2011	4.19%
7/7/1986	7.159	7.16%	8.80%	4/5/2011	4.19%

7/3/1986	7.164	7.16%	8.82%	4/6/2011	4.20%
7/2/1986	7.215	7.22%	8.84%	4/7/2011	4.20%
7/1/1986	7.195	7.20%	8.85%	4/8/2011	4.20%
6/30/1986	7.23	7.23%	8.87%	4/11/2011	4.21%
6/27/1986	7.277	7.28%	8.89%	4/12/2011	4.21%
6/26/1986	7.339	7.34%	8.91%	4/13/2011	4.21%
6/25/1986	7.355	7.36%	8.92%	4/14/2011	4.22%
6/24/1986	7.345	7.35%	8.94%	4/15/2011	4.22%
6/23/1986	7.456	7.46%	8.95%	4/18/2011	4.22%
6/20/1986	7.434	7.43%	8.97%	4/19/2011	4.22%
6/19/1986	7.526	7.53%	8.98%	4/20/2011	4.22%
6/18/1986	7.44	7.44%	9.00%	4/21/2011	4.23%
6/17/1986	7.408	7.41%	9.01%	4/22/2011	4.23%
6/16/1986	7.445	7.45%	9.03%	4/25/2011	4.23%
6/13/1986	7.464	7.46%	9.04%	4/26/2011	4.23%
6/12/1986	7.647	7.65%	9.06%	4/27/2011	4.24%
6/11/1986	7.719	7.72%	9.07%	4/28/2011	4.24%
6/10/1986	7.742	7.74%	9.08%	4/29/2011	4.24%
6/9/1986	7.765	7.77%	9.10%	5/2/2011	4.24%
6/6/1986	7.666	7.67%	9.11%	5/3/2011	4.24%
6/5/1986	7.886	7.89%	9.13%	5/4/2011	4.24%
6/4/1986	7.886	7.89%	9.14%	5/5/2011	4.25%
6/3/1986	7.805	7.81%	9.15%	5/6/2011	4.25%
6/2/1986	7.915	7.92%	9.17%	5/9/2011	4.25%
5/30/1986	7.748	7.75%	9.18%	5/10/2011	4.25%
5/29/1986	7.692	7.69%	9.19%	5/11/2011	4.25%
5/28/1986	7.467	7.47%	9.21%	5/12/2011	4.25%
5/27/1986	7.387	7.39%	9.23%	5/13/2011	4.25%
5/23/1986	7.435	7.44%	9.24%	5/16/2011	4.26%
5/22/1986	7.502	7.50%	9.26%	5/17/2011	4.26%
5/21/1986	7.581	7.58%	9.28%	5/18/2011	4.26%
5/20/1986	7.543	7.54%	9.29%	5/19/2011	4.26%
5/19/1986	7.703	7.70%	9.31%	5/20/2011	4.26%
5/16/1986	7.614	7.61%	9.32%	5/23/2011	4.27%
5/15/1986	7.554	7.55%	9.34%	5/24/2011	4.27%
5/14/1986	7.456	7.46%	9.35%	5/25/2011	4.27%
5/13/1986	7.398	7.40%	9.37%	5/26/2011	4.27%
5/12/1986	7.435	7.44%	9.38%	5/27/2011	4.28%
5/9/1986	7.351	7.35%	9.40%	5/30/2011	4.28%
5/8/1986	7.403	7.40%	9.42%	5/31/2011	4.28%
5/7/1986	7.508	7.51%	9.43%	6/1/2011	4.29%
5/6/1986	7.492	7.49%	9.45%	6/2/2011	4.29%
5/5/1986	7.445	7.45%	9.46%	6/3/2011	4.29%
5/2/1986	7.618	7.62%	9.48%	6/6/2011	4.29%
5/1/1986	7.549	7.55%	9.49%	6/7/2011	4.30%
4/30/1986	7.45	7.45%	9.50%	6/8/2011	4.30%
4/29/1986	7.414	7.41%	9.52%	6/9/2011	4.30%

4/28/1986	7.495	7.50%	9.53%	6/10/2011	4.31%
4/25/1986	7.567	7.57%	9.55%	6/13/2011	4.31%
4/24/1986	7.613	7.61%	9.56%	6/14/2011	4.31%
4/23/1986	7.439	7.44%	9.57%	6/15/2011	4.31%
4/22/1986	7.331	7.33%	9.59%	6/16/2011	4.32%
4/21/1986	7.147	7.15%	9.61%	6/17/2011	4.32%
4/18/1986	7.153	7.15%	9.62%	6/20/2011	4.32%
4/17/1986	7.128	7.13%	9.64%	6/21/2011	4.32%
4/16/1986	7.109	7.11%	9.66%	6/22/2011	4.32%
4/15/1986	7.318	7.32%	9.67%	6/23/2011	4.32%
4/14/1986	7.288	7.29%	9.69%	6/24/2011	4.32%
4/11/1986	7.362	7.36%	9.71%	6/27/2011	4.33%
4/10/1986	7.308	7.31%	9.72%	6/28/2011	4.33%
4/9/1986	7.321	7.32%	9.74%	6/29/2011	4.33%
4/8/1986	7.36	7.36%	9.75%	6/30/2011	4.34%
4/7/1986	7.577	7.58%	9.77%	7/1/2011	4.34%
4/4/1986	7.55	7.55%	9.78%	7/4/2011	4.34%
4/3/1986	7.474	7.47%	9.79%	7/5/2011	4.35%
4/2/1986	7.38	7.38%	9.81%	7/6/2011	4.35%
4/1/1986	7.456	7.46%	9.83%	7/7/2011	4.35%
3/31/1986	7.44	7.44%	9.84%	7/8/2011	4.36%
3/27/1986	7.592	7.59%	9.86%	7/11/2011	4.36%
3/26/1986	7.783	7.78%	9.87%	7/12/2011	4.36%
3/25/1986	7.888	7.89%	9.88%	7/13/2011	4.36%
3/24/1986	7.932	7.93%	9.89%	7/14/2011	4.37%
3/21/1986	7.969	7.97%	9.91%	7/15/2011	4.37%
3/20/1986	7.952	7.95%	9.92%	7/18/2011	4.37%
3/19/1986	7.991	7.99%	9.93%	7/19/2011	4.37%
3/18/1986	7.952	7.95%	9.95%	7/20/2011	4.37%
3/17/1986	7.979	7.98%	9.96%	7/21/2011	4.38%
3/14/1986	7.952	7.95%	9.97%	7/22/2011	4.38%
3/13/1986	7.913	7.91%	9.99%	7/25/2011	4.38%
3/12/1986	7.943	7.94%	10.00%	7/26/2011	4.38%
3/11/1986	7.894	7.89%	10.02%	7/27/2011	4.38%
3/10/1986	8.002	8.00%	10.03%	7/28/2011	4.39%
3/7/1986	8.145	8.15%	10.05%	7/29/2011	4.39%
3/6/1986	8.193	8.19%	10.06%	8/1/2011	4.39%
3/5/1986	8.24	8.24%	10.08%	8/2/2011	4.39%
3/4/1986	8.052	8.05%	10.09%	8/3/2011	4.39%
3/3/1986	8.094	8.09%	10.11%	8/4/2011	4.38%
2/28/1986	8.281	8.28%	10.12%	8/5/2011	4.38%
2/27/1986	8.297	8.30%	10.14%	8/8/2011	4.38%
2/26/1986	8.456	8.46%	10.15%	8/9/2011	4.38%
2/25/1986	8.614	8.61%	10.17%	8/10/2011	4.38%
2/24/1986	8.625	8.63%	10.18%	8/11/2011	4.38%
2/21/1986	8.698	8.70%	10.19%	8/12/2011	4.37%
2/20/1986	8.857	8.86%	10.21%	8/15/2011	4.37%

2/19/1986	8.909	8.91%	10.22%	8/16/2011	4.37%
2/18/1986	8.892	8.89%	10.23%	8/17/2011	4.37%
2/14/1986	8.939	8.94%	10.24%	8/18/2011	4.36%
2/13/1986	9.045	9.05%	10.26%	8/19/2011	4.36%
2/12/1986	9.129	9.13%	10.27%	8/22/2011	4.35%
2/11/1986	9.16	9.16%	10.28%	8/23/2011	4.35%
2/10/1986	9.203	9.20%	10.29%	8/24/2011	4.35%
2/7/1986	9.292	9.29%	10.30%	8/25/2011	4.34%
2/6/1986	9.265	9.27%	10.31%	8/26/2011	4.34%
2/5/1986	9.278	9.28%	10.32%	8/29/2011	4.34%
2/4/1986	9.236	9.24%	10.33%	8/30/2011	4.33%
2/3/1986	9.242	9.24%	10.34%	8/31/2011	4.33%
1/31/1986	9.319	9.32%	10.35%	9/1/2011	4.32%
1/30/1986	9.343	9.34%	10.36%	9/2/2011	4.32%
1/29/1986	9.337	9.34%	10.37%	9/5/2011	4.32%
1/28/1986	9.284	9.28%	10.38%	9/6/2011	4.31%
1/27/1986	9.355	9.36%	10.39%	9/7/2011	4.31%
1/24/1986	9.415	9.42%	10.41%	9/8/2011	4.30%
1/23/1986	9.409	9.41%	10.42%	9/9/2011	4.30%
1/22/1986	9.427	9.43%	10.43%	9/12/2011	4.29%
1/21/1986	9.415	9.42%	10.44%	9/13/2011	4.29%
1/17/1986	9.421	9.42%	10.45%	9/14/2011	4.28%
1/16/1986	9.355	9.36%	10.46%	9/15/2011	4.28%
1/15/1986	9.403	9.40%	10.47%	9/16/2011	4.27%
1/14/1986	9.556	9.56%	10.49%	9/19/2011	4.26%
1/13/1986	9.606	9.61%	10.50%	9/20/2011	4.26%
1/10/1986	9.569	9.57%	10.51%	9/21/2011	4.25%
1/9/1986	9.44	9.44%	10.52%	9/22/2011	4.24%
1/8/1986	9.32	9.32%	10.53%	9/23/2011	4.23%
1/7/1986	9.161	9.16%	10.54%	9/26/2011	4.23%
1/6/1986	9.302	9.30%	10.56%	9/27/2011	4.22%
1/3/1986	9.278	9.28%	10.57%	9/28/2011	4.21%
1/2/1986	9.273	9.27%	10.58%	9/29/2011	4.21%
12/31/1985	9.267	9.27%	10.59%	9/30/2011	4.20%
12/30/1985	9.261	9.26%	10.61%	10/3/2011	4.19%
12/27/1985	9.267	9.27%	10.62%	10/4/2011	4.18%
12/26/1985	9.291	9.29%	10.63%	10/5/2011	4.17%
12/24/1985	9.32	9.32%	10.64%	10/6/2011	4.17%
12/23/1985	9.338	9.34%	10.66%	10/7/2011	4.16%
12/20/1985	9.326	9.33%	10.67%	10/10/2011	4.15%
12/19/1985	9.392	9.39%	10.68%	10/11/2011	4.15%
12/18/1985	9.392	9.39%	10.69%	10/12/2011	4.14%
12/17/1985	9.339	9.34%	10.70%	10/13/2011	4.13%
12/16/1985	9.447	9.45%	10.71%	10/14/2011	4.13%
12/13/1985	9.52	9.52%	10.72%	10/17/2011	4.12%
12/12/1985	9.539	9.54%	10.73%	10/18/2011	4.11%
12/11/1985	9.527	9.53%	10.74%	10/19/2011	4.11%

12/10/1985	9.664	9.66%	10.75%	10/20/2011	4.10%
12/9/1985	9.714	9.71%	10.76%	10/21/2011	4.09%
12/6/1985	9.856	9.86%	10.76%	10/24/2011	4.09%
12/5/1985	9.876	9.88%	10.77%	10/25/2011	4.08%
12/4/1985	9.863	9.86%	10.78%	10/26/2011	4.07%
12/3/1985	9.882	9.88%	10.79%	10/27/2011	4.07%
12/2/1985	9.935	9.94%	10.79%	10/28/2011	4.06%
11/29/1985	9.837	9.84%	10.80%	10/31/2011	4.05%
11/27/1985	9.896	9.90%	10.80%	11/1/2011	4.05%
11/26/1985	9.949	9.95%	10.81%	11/2/2011	4.04%
11/25/1985	9.962	9.96%	10.82%	11/3/2011	4.03%
11/22/1985	9.996	10.00%	10.82%	11/4/2011	4.02%
11/21/1985	9.921	9.92%	10.83%	11/7/2011	4.02%
11/20/1985	9.915	9.92%	10.84%	11/8/2011	4.01%
11/19/1985	9.977	9.98%	10.84%	11/9/2011	4.00%
11/18/1985	10.008	10.01%	10.85%	11/10/2011	3.99%
11/15/1985	10.135	10.14%	10.86%	11/11/2011	3.99%
11/14/1985	10.161	10.16%	10.87%	11/14/2011	3.98%
11/13/1985	10.059	10.06%	10.87%	11/15/2011	3.97%
11/12/1985	10.027	10.03%	10.88%	11/16/2011	3.96%
11/8/1985	10.129	10.13%	10.89%	11/17/2011	3.95%
11/7/1985	10.168	10.17%	10.90%	11/18/2011	3.94%
11/6/1985	10.181	10.18%	10.90%	11/21/2011	3.94%
11/5/1985	10.161	10.16%	10.91%	11/22/2011	3.93%
11/4/1985	10.207	10.21%	10.92%	11/23/2011	3.92%
11/1/1985	10.226	10.23%	10.92%	11/24/2011	3.91%
10/31/1985	10.246	10.25%	10.93%	11/25/2011	3.90%
10/30/1985	10.265	10.27%	10.94%	11/28/2011	3.89%
10/29/1985	10.325	10.33%	10.94%	11/29/2011	3.88%
10/28/1985	10.513	10.51%	10.95%	11/30/2011	3.87%
10/25/1985	10.445	10.45%	10.95%	12/1/2011	3.87%
10/24/1985	10.391	10.39%	10.96%	12/2/2011	3.86%
10/23/1985	10.371	10.37%	10.96%	12/5/2011	3.85%
10/22/1985	10.371	10.37%	10.97%	12/6/2011	3.85%
10/21/1985	10.425	10.43%	10.97%	12/7/2011	3.84%
10/18/1985	10.439	10.44%	10.98%	12/8/2011	3.83%
10/17/1985	10.445	10.45%	10.98%	12/9/2011	3.82%
10/16/1985	10.527	10.53%	10.99%	12/12/2011	3.81%
10/15/1985	10.534	10.53%	10.99%	12/13/2011	3.81%
10/11/1985	10.596	10.60%	11.00%	12/14/2011	3.80%
10/10/1985	10.589	10.59%	11.00%	12/15/2011	3.79%
10/9/1985	10.61	10.61%	11.01%	12/16/2011	3.78%
10/8/1985	10.603	10.60%	11.01%	12/19/2011	3.77%
10/7/1985	10.652	10.65%	11.02%	12/20/2011	3.76%
10/4/1985	10.624	10.62%	11.02%	12/21/2011	3.76%
10/3/1985	10.582	10.58%	11.03%	12/22/2011	3.75%
10/2/1985	10.555	10.56%	11.03%	12/23/2011	3.74%

10/1/1985	10.534	10.53%	11.04%	12/26/2011	3.74%
9/30/1985	10.555	10.56%	11.04%	12/27/2011	3.73%
9/27/1985	10.548	10.55%	11.05%	12/28/2011	3.72%
9/26/1985	10.494	10.49%	11.05%	12/29/2011	3.71%
9/25/1985	10.514	10.51%	11.05%	12/30/2011	3.71%
9/24/1985	10.569	10.57%	11.06%	1/2/2012	3.70%
9/23/1985	10.624	10.62%	11.06%	1/3/2012	3.69%
9/20/1985	10.576	10.58%	11.07%	1/4/2012	3.68%
9/19/1985	10.611	10.61%	11.07%	1/5/2012	3.68%
9/18/1985	10.681	10.68%	11.08%	1/6/2012	3.67%
9/17/1985	10.604	10.60%	11.08%	1/9/2012	3.66%
9/16/1985	10.569	10.57%	11.09%	1/10/2012	3.65%
9/13/1985	10.583	10.58%	11.09%	1/11/2012	3.65%
9/12/1985	10.751	10.75%	11.10%	1/12/2012	3.64%
9/11/1985	10.709	10.71%	11.11%	1/13/2012	3.63%
9/10/1985	10.695	10.70%	11.11%	1/16/2012	3.62%
9/9/1985	10.702	10.70%	11.11%	1/17/2012	3.61%
9/6/1985	10.702	10.70%	11.12%	1/18/2012	3.60%
9/5/1985	10.474	10.47%	11.12%	1/19/2012	3.60%
9/4/1985	10.394	10.39%	11.13%	1/20/2012	3.59%
9/3/1985	10.441	10.44%	11.13%	1/23/2012	3.58%
8/30/1985	10.468	10.47%	11.14%	1/24/2012	3.58%
8/29/1985	10.361	10.36%	11.15%	1/25/2012	3.57%
8/28/1985	10.361	10.36%	11.15%	1/26/2012	3.56%
8/27/1985	10.367	10.37%	11.16%	1/27/2012	3.56%
8/26/1985	10.435	10.44%	11.16%	1/30/2012	3.55%
8/23/1985	10.435	10.44%	11.17%	1/31/2012	3.54%
8/22/1985	10.408	10.41%	11.18%	2/1/2012	3.53%
8/21/1985	10.411	10.41%	11.19%	2/2/2012	3.53%
8/20/1985	10.462	10.46%	11.19%	2/3/2012	3.52%
8/19/1985	10.503	10.50%	11.20%	2/6/2012	3.51%
8/16/1985	10.517	10.52%	11.21%	2/7/2012	3.51%
8/15/1985	10.676	10.68%	11.22%	2/8/2012	3.50%
8/14/1985	10.599	10.60%	11.23%	2/9/2012	3.50%
8/13/1985	10.683	10.68%	11.23%	2/10/2012	3.49%
8/12/1985	10.641	10.64%	11.24%	2/13/2012	3.49%
8/9/1985	10.599	10.60%	11.25%	2/14/2012	3.48%
8/8/1985	10.662	10.66%	11.26%	2/15/2012	3.47%
8/7/1985	10.698	10.70%	11.27%	2/16/2012	3.47%
8/6/1985	10.718	10.72%	11.27%	2/17/2012	3.46%
8/5/1985	10.718	10.72%	11.28%	2/20/2012	3.46%
8/2/1985	10.772	10.77%	11.29%	2/21/2012	3.45%
8/1/1985	10.637	10.64%	11.30%	2/22/2012	3.44%
7/31/1985	10.657	10.66%	11.30%	2/23/2012	3.44%
7/30/1985	10.765	10.77%	11.31%	2/24/2012	3.43%
7/29/1985	10.764	10.76%	11.32%	2/27/2012	3.43%
7/26/1985	10.737	10.74%	11.33%	2/28/2012	3.42%

7/25/1985	10.61	10.61%	11.33%	2/29/2012	3.41%
7/24/1985	10.604	10.60%	11.34%	3/1/2012	3.41%
7/23/1985	10.571	10.57%	11.35%	3/2/2012	3.40%
7/22/1985	10.577	10.58%	11.36%	3/5/2012	3.40%
7/19/1985	10.492	10.49%	11.36%	3/6/2012	3.39%
7/18/1985	10.498	10.50%	11.37%	3/7/2012	3.39%
7/17/1985	10.294	10.29%	11.38%	3/8/2012	3.38%
7/16/1985	10.344	10.34%	11.39%	3/9/2012	3.38%
7/15/1985	10.453	10.45%	11.40%	3/12/2012	3.37%
7/12/1985	10.44	10.44%	11.41%	3/13/2012	3.37%
7/11/1985	10.44	10.44%	11.42%	3/14/2012	3.36%
7/10/1985	10.338	10.34%	11.43%	3/15/2012	3.36%
7/9/1985	10.281	10.28%	11.45%	3/16/2012	3.35%
7/8/1985	10.281	10.28%	11.46%	3/19/2012	3.35%
7/5/1985	10.275	10.28%	11.47%	3/20/2012	3.35%
7/3/1985	10.427	10.43%	11.48%	3/21/2012	3.34%
7/2/1985	10.427	10.43%	11.49%	3/22/2012	3.34%
7/1/1985	10.427	10.43%	11.50%	3/23/2012	3.33%
6/28/1985	10.439	10.44%	11.51%	3/26/2012	3.33%
6/27/1985	10.55	10.55%	11.52%	3/27/2012	3.33%
6/26/1985	10.622	10.62%	11.53%	3/28/2012	3.32%
6/25/1985	10.695	10.70%	11.54%	3/29/2012	3.32%
6/24/1985	10.609	10.61%	11.55%	3/30/2012	3.31%
6/21/1985	10.563	10.56%	11.56%	4/2/2012	3.31%
6/20/1985	10.491	10.49%	11.57%	4/3/2012	3.30%
6/19/1985	10.369	10.37%	11.58%	4/4/2012	3.30%
6/18/1985	10.237	10.24%	11.59%	4/5/2012	3.29%
6/17/1985	10.255	10.26%	11.60%	4/6/2012	3.29%
6/14/1985	10.343	10.34%	11.61%	4/9/2012	3.28%
6/13/1985	10.458	10.46%	11.62%	4/10/2012	3.27%
6/12/1985	10.458	10.46%	11.63%	4/11/2012	3.27%
6/10/1985	10.433	10.43%	11.64%	4/12/2012	3.26%
6/7/1985	10.523	10.52%	11.65%	4/13/2012	3.26%
6/6/1985	10.306	10.31%	11.66%	4/16/2012	3.25%
6/5/1985	10.268	10.27%	11.67%	4/17/2012	3.25%
6/4/1985	10.318	10.32%	11.69%	4/18/2012	3.24%
6/3/1985	10.381	10.38%	11.70%	4/19/2012	3.24%
5/31/1985	10.556	10.56%	11.71%	4/20/2012	3.23%
5/30/1985	10.695	10.70%	11.72%	4/23/2012	3.22%
5/29/1985	10.675	10.68%	11.73%	4/24/2012	3.22%
5/28/1985	10.708	10.71%	11.75%	4/25/2012	3.21%
5/24/1985	10.83	10.83%	11.76%	4/26/2012	3.21%
5/23/1985	10.899	10.90%	11.77%	4/27/2012	3.20%
5/22/1985	10.927	10.93%	11.78%	4/30/2012	3.20%
5/21/1985	10.851	10.85%	11.79%	5/1/2012	3.19%
5/20/1985	10.796	10.80%	11.80%	5/2/2012	3.18%
5/17/1985	10.906	10.91%	11.81%	5/3/2012	3.18%

5/16/1985	11.011	11.01%	11.82%	5/4/2012	3.17%
5/15/1985	11.075	11.08%	11.84%	5/7/2012	3.17%
5/14/1985	11.025	11.03%	11.85%	5/8/2012	3.16%
5/13/1985	11.168	11.17%	11.86%	5/9/2012	3.16%
5/10/1985	11.197	11.20%	11.87%	5/10/2012	3.16%
5/9/1985	11.336	11.34%	11.88%	5/11/2012	3.15%
5/8/1985	11.365	11.37%	11.89%	5/14/2012	3.15%
5/7/1985	11.27	11.27%	11.90%	5/15/2012	3.14%
5/6/1985	11.262	11.26%	11.91%	5/16/2012	3.14%
5/3/1985	11.299	11.30%	11.92%	5/17/2012	3.14%
5/2/1985	11.336	11.34%	11.94%	5/18/2012	3.13%
5/1/1985	11.38	11.38%	11.95%	5/21/2012	3.13%
4/30/1985	11.463	11.46%	11.96%	5/22/2012	3.12%
4/29/1985	11.516	11.52%	11.97%	5/23/2012	3.12%
4/26/1985	11.403	11.40%	11.98%	5/24/2012	3.12%
4/25/1985	11.441	11.44%	11.99%	5/25/2012	3.11%
4/24/1985	11.377	11.38%	12.00%	5/28/2012	3.11%
4/23/1985	11.307	11.31%	12.01%	5/29/2012	3.11%
4/22/1985	11.211	11.21%	12.02%	5/30/2012	3.10%
4/19/1985	11.248	11.25%	12.03%	5/31/2012	3.10%
4/18/1985	11.226	11.23%	12.04%	6/1/2012	3.09%
4/17/1985	11.321	11.32%	12.05%	6/4/2012	3.09%
4/16/1985	11.274	11.27%	12.06%	6/5/2012	3.08%
4/15/1985	11.351	11.35%	12.07%	6/6/2012	3.08%
4/12/1985	11.388	11.39%	12.08%	6/7/2012	3.08%
4/11/1985	11.392	11.39%	12.09%	6/8/2012	3.07%
4/10/1985	11.54	11.54%	12.10%	6/11/2012	3.07%
4/9/1985	11.589	11.59%	12.11%	6/12/2012	3.07%
4/8/1985	11.726	11.73%	12.12%	6/13/2012	3.06%
4/4/1985	11.648	11.65%	12.12%	6/14/2012	3.06%
4/3/1985	11.691	11.69%	12.14%	6/15/2012	3.06%
4/2/1985	11.671	11.67%	12.15%	6/18/2012	3.06%
4/1/1985	11.636	11.64%	12.16%	6/19/2012	3.05%
3/29/1985	11.64	11.64%	12.17%	6/20/2012	3.05%
3/28/1985	11.687	11.69%	12.18%	6/21/2012	3.05%
3/27/1985	11.805	11.81%	12.19%	6/22/2012	3.04%
3/26/1985	11.75	11.75%	12.20%	6/25/2012	3.04%
3/25/1985	11.75	11.75%	12.20%	6/26/2012	3.04%
3/22/1985	11.813	11.81%	12.21%	6/27/2012	3.04%
3/21/1985	11.711	11.71%	12.22%	6/28/2012	3.04%
3/20/1985	11.806	11.81%	12.23%	6/29/2012	3.04%
3/19/1985	11.87	11.87%	12.24%	7/2/2012	3.03%
3/18/1985	11.934	11.93%	12.25%	7/3/2012	3.03%
3/14/1985	11.87	11.87%	12.25%	7/4/2012	3.03%
3/13/1985	11.822	11.82%	12.26%	7/5/2012	3.03%
3/12/1985	11.688	11.69%	12.27%	7/6/2012	3.03%
3/11/1985	11.727	11.73%	12.28%	7/9/2012	3.03%

3/8/1985	11.696	11.70%	12.28%	7/10/2012	3.03%
3/7/1985	11.887	11.89%	12.29%	7/11/2012	3.03%
3/6/1985	11.911	11.91%	12.30%	7/12/2012	3.02%
3/5/1985	11.807	11.81%	12.30%	7/13/2012	3.02%
2/28/1985	11.875	11.88%	12.31%	7/16/2012	3.02%
2/20/1985	11.535	11.54%	12.31%	7/17/2012	3.02%
2/19/1985	11.377	11.38%	12.32%	7/18/2012	3.01%
2/15/1985	11.325	11.33%	12.32%	7/19/2012	3.01%
2/14/1985	11.208	11.21%	12.33%	7/20/2012	3.01%
2/13/1985	11.281	11.28%	12.34%	7/23/2012	3.00%
2/11/1985	11.325	11.33%	12.35%	7/24/2012	3.00%
2/8/1985	11.256	11.26%	12.35%	7/25/2012	3.00%
2/7/1985	11.311	11.31%	12.36%	7/26/2012	2.99%
2/6/1985	11.316	11.32%	12.37%	7/27/2012	2.99%
2/5/1985	11.265	11.27%	12.37%	7/30/2012	2.99%
2/4/1985	11.301	11.30%	12.38%	7/31/2012	2.98%
2/1/1985	11.316	11.32%	12.39%	8/1/2012	2.98%
1/31/1985	11.207	11.21%	12.39%	8/2/2012	2.98%
1/30/1985	11.121	11.12%	12.40%	8/3/2012	2.97%
1/29/1985	11.064	11.06%	12.40%	8/6/2012	2.97%
1/28/1985	11.178	11.18%	12.41%	8/7/2012	2.97%
1/25/1985	11.167	11.17%	12.42%	8/8/2012	2.97%
1/24/1985	11.157	11.16%	12.43%	8/9/2012	2.97%
1/23/1985	11.309	11.31%	12.43%	8/10/2012	2.96%
1/22/1985	11.353	11.35%	12.44%	8/13/2012	2.96%
1/18/1985	11.51	11.51%	12.45%	8/14/2012	2.96%
1/17/1985	11.495	11.50%	12.45%	8/15/2012	2.96%
1/15/1985	11.555	11.56%	12.46%	8/16/2012	2.96%
1/14/1985	11.631	11.63%	12.46%	8/17/2012	2.96%
1/11/1985	11.624	11.62%	12.46%	8/20/2012	2.96%
1/10/1985	11.533	11.53%	12.47%	8/21/2012	2.96%
1/9/1985	11.495	11.50%	12.47%	8/22/2012	2.96%
1/8/1985	11.45	11.45%	12.48%	8/23/2012	2.95%
1/7/1985	11.514	11.51%	12.48%	8/24/2012	2.95%
1/4/1985	11.624	11.62%	12.49%	8/27/2012	2.95%
1/3/1985	11.601	11.60%	12.49%	8/28/2012	2.95%
1/2/1985	11.725	11.73%	12.50%	8/29/2012	2.95%
12/31/1984	11.526	11.53%	12.50%	8/30/2012	2.95%
12/28/1984	11.481	11.48%	12.50%	8/31/2012	2.95%
12/27/1984	11.458	11.46%	12.51%	9/3/2012	2.95%
12/26/1984	11.451	11.45%	12.51%	9/4/2012	2.95%
12/24/1984	11.34	11.34%	12.52%	9/5/2012	2.95%
12/21/1984	11.362	11.36%	12.52%	9/6/2012	2.94%
12/20/1984	11.355	11.36%	12.53%	9/7/2012	2.94%
12/19/1984	11.384	11.38%	12.53%	9/10/2012	2.94%
12/18/1984	11.355	11.36%	12.53%	9/11/2012	2.94%
12/17/1984	11.459	11.46%	12.54%	9/12/2012	2.94%

12/14/1984	11.587	11.59%	12.54%	9/13/2012	2.94%
12/13/1984	11.61	11.61%	12.54%	9/14/2012	2.94%
12/12/1984	11.512	11.51%	12.55%	9/17/2012	2.94%
12/11/1984	11.572	11.57%	12.55%	9/18/2012	2.94%
12/10/1984	11.611	11.61%	12.55%	9/19/2012	2.94%
12/7/1984	11.672	11.67%	12.55%	9/20/2012	2.94%
12/6/1984	11.573	11.57%	12.56%	9/21/2012	2.94%
12/5/1984	11.543	11.54%	12.56%	9/24/2012	2.94%
12/4/1984	11.505	11.51%	12.56%	9/25/2012	2.94%
12/3/1984	11.52	11.52%	12.56%	9/26/2012	2.94%
11/30/1984	11.528	11.53%	12.56%	9/27/2012	2.94%
11/29/1984	11.498	11.50%	12.57%	9/28/2012	2.94%
11/28/1984	11.364	11.36%	12.57%	10/1/2012	2.94%
11/27/1984	11.305	11.31%	12.57%	10/2/2012	2.94%
11/26/1984	11.313	11.31%	12.57%	10/3/2012	2.93%
11/23/1984	11.298	11.30%	12.58%	10/4/2012	2.93%
11/21/1984	11.417	11.42%	12.58%	10/5/2012	2.93%
11/20/1984	11.537	11.54%	12.58%	10/8/2012	2.94%
11/19/1984	11.575	11.58%	12.58%	10/9/2012	2.94%
11/16/1984	11.659	11.66%	12.58%	10/10/2012	2.93%
11/15/1984	11.678	11.68%	12.58%	10/11/2012	2.93%
11/14/1984	11.813	11.81%	12.58%	10/12/2012	2.93%
11/13/1984	11.725	11.73%	12.58%	10/15/2012	2.93%
11/9/1984	11.644	11.64%	12.58%	10/16/2012	2.93%
11/8/1984	11.752	11.75%	12.58%	10/17/2012	2.93%
11/7/1984	11.644	11.64%	12.58%	10/18/2012	2.93%
11/5/1984	11.45	11.45%	12.58%	10/19/2012	2.93%
11/2/1984	11.5	11.50%	12.58%	10/22/2012	2.93%
11/1/1984	11.465	11.47%	12.58%	10/23/2012	2.93%
10/31/1984	11.558	11.56%	12.58%	10/24/2012	2.93%
10/30/1984	11.565	11.57%	12.58%	10/25/2012	2.93%
10/29/1984	11.696	11.70%	12.58%	10/26/2012	2.93%
10/26/1984	11.733	11.73%	12.58%	10/29/2012	2.93%
10/25/1984	11.711	11.71%	12.58%	10/30/2012	2.93%
10/24/1984	11.572	11.57%	12.58%	10/31/2012	2.93%
10/23/1984	11.58	11.58%	12.59%	11/1/2012	2.93%
10/22/1984	11.638	11.64%	12.59%	11/2/2012	2.92%
10/19/1984	11.711	11.71%	12.59%	11/5/2012	2.92%
10/18/1984	11.793	11.79%	12.59%	11/6/2012	2.92%
10/17/1984	12.02	12.02%	12.59%	11/7/2012	2.92%
10/16/1984	12.121	12.12%	12.59%	11/8/2012	2.92%
10/15/1984	12.121	12.12%	12.59%	11/9/2012	2.92%
10/12/1984	12.113	12.11%	12.59%	11/12/2012	2.92%
10/11/1984	12.144	12.14%	12.58%	11/13/2012	2.92%
10/10/1984	12.16	12.16%	12.58%	11/14/2012	2.91%
10/9/1984	12.121	12.12%	12.58%	11/15/2012	2.91%
10/5/1984	12.184	12.18%	12.58%	11/16/2012	2.91%

10/4/1984	12.271	12.27%	12.58%	11/19/2012	2.91%
10/3/1984	12.383	12.38%	12.58%	11/20/2012	2.91%
10/2/1984	12.303	12.30%	12.57%	11/21/2012	2.91%
10/1/1984	12.343	12.34%	12.57%	11/22/2012	2.90%
9/28/1984	12.247	12.25%	12.57%	11/23/2012	2.90%
9/27/1984	12.106	12.11%	12.57%	11/26/2012	2.90%
9/26/1984	12.216	12.22%	12.57%	11/27/2012	2.90%
9/25/1984	12.303	12.30%	12.57%	11/28/2012	2.90%
9/24/1984	12.303	12.30%	12.57%	11/29/2012	2.89%
9/21/1984	12.224	12.22%	12.56%	11/30/2012	2.89%
9/20/1984	12.107	12.11%	12.56%	12/3/2012	2.89%
9/19/1984	12.049	12.05%	12.56%	12/4/2012	2.89%
9/18/1984	12.138	12.14%	12.56%	12/5/2012	2.89%
9/17/1984	12.154	12.15%	12.56%	12/6/2012	2.89%
9/14/1984	12.162	12.16%	12.55%	12/7/2012	2.89%
9/13/1984	12.084	12.08%	12.55%	12/10/2012	2.88%
9/12/1984	12.249	12.25%	12.55%	12/11/2012	2.88%
9/11/1984	12.321	12.32%	12.54%	12/12/2012	2.88%
9/10/1984	12.329	12.33%	12.54%	12/13/2012	2.88%
9/7/1984	12.426	12.43%	12.54%	12/14/2012	2.88%
9/6/1984	12.467	12.47%	12.53%	12/17/2012	2.88%
9/5/1984	12.592	12.59%	12.53%	12/18/2012	2.88%
9/4/1984	12.588	12.59%	12.53%	12/19/2012	2.87%
8/31/1984	12.508	12.51%	12.52%	12/20/2012	2.87%
8/30/1984	12.573	12.57%	12.52%	12/21/2012	2.87%
8/29/1984	12.573	12.57%	12.51%	12/24/2012	2.87%
8/28/1984	12.533	12.53%	12.51%	12/25/2012	2.86%
8/27/1984	12.565	12.57%	12.51%	12/26/2012	2.86%
8/24/1984	12.444	12.44%	12.50%	12/27/2012	2.86%
8/23/1984	12.427	12.43%	12.50%	12/28/2012	2.86%
8/22/1984	12.428	12.43%	12.50%	12/31/2012	2.86%
8/21/1984	12.299	12.30%	12.49%	1/1/2013	2.85%
8/20/1984	12.387	12.39%	12.49%	1/2/2013	2.85%
8/17/1984	12.436	12.44%	12.49%	1/3/2013	2.85%
8/16/1984	12.477	12.48%	12.48%	1/4/2013	2.85%
8/15/1984	12.632	12.63%	12.48%	1/7/2013	2.85%
8/14/1984	12.461	12.46%	12.48%	1/8/2013	2.85%
8/13/1984	12.526	12.53%	12.47%	1/9/2013	2.85%
8/10/1984	12.486	12.49%	12.47%	1/10/2013	2.85%
8/9/1984	12.332	12.33%	12.46%	1/11/2013	2.84%
8/8/1984	12.592	12.59%	12.46%	1/14/2013	2.84%
8/7/1984	12.576	12.58%	12.45%	1/15/2013	2.84%
8/6/1984	12.632	12.63%	12.45%	1/16/2013	2.84%
8/3/1984	12.474	12.47%	12.44%	1/17/2013	2.84%
8/2/1984	12.545	12.55%	12.44%	1/18/2013	2.84%
8/1/1984	12.736	12.74%	12.43%	1/21/2013	2.84%
7/31/1984	12.768	12.77%	12.43%	1/22/2013	2.84%

7/30/1984	12.883	12.88%	12.42%	1/23/2013	2.84%
7/27/1984	12.809	12.81%	12.41%	1/24/2013	2.84%
7/26/1984	12.736	12.74%	12.41%	1/25/2013	2.84%
7/25/1984	12.916	12.92%	12.40%	1/28/2013	2.84%
7/24/1984	13.117	13.12%	12.39%	1/29/2013	2.84%
7/23/1984	13.142	13.14%	12.38%	1/30/2013	2.84%
7/20/1984	13.168	13.17%	12.38%	1/31/2013	2.84%
7/19/1984	13.092	13.09%	12.37%	2/1/2013	2.84%
7/18/1984	13.066	13.07%	12.36%	2/4/2013	2.84%
7/17/1984	13.126	13.13%	12.35%	2/5/2013	2.84%
7/16/1984	13.134	13.13%	12.34%	2/6/2013	2.84%
7/13/1984	13.041	13.04%	12.33%	2/7/2013	2.84%
7/12/1984	13.16	13.16%	12.32%	2/8/2013	2.84%
7/11/1984	13.28	13.28%	12.32%	2/11/2013	2.84%
7/10/1984	13.28	13.28%	12.31%	2/12/2013	2.84%
7/9/1984	13.177	13.18%	12.30%	2/13/2013	2.84%
7/6/1984	13.461	13.46%	12.29%	2/14/2013	2.84%
7/5/1984	13.531	13.53%	12.28%	2/15/2013	2.85%
7/3/1984	13.452	13.45%	12.28%	2/18/2013	2.85%
7/2/1984	13.619	13.62%	12.27%	2/19/2013	2.85%
6/29/1984	13.638	13.64%	12.26%	2/20/2013	2.85%
6/28/1984	13.602	13.60%	12.25%	2/21/2013	2.85%
6/27/1984	13.549	13.55%	12.24%	2/22/2013	2.85%
6/26/1984	13.54	13.54%	12.23%	2/25/2013	2.85%
6/25/1984	13.567	13.57%	12.22%	2/26/2013	2.86%
6/22/1984	13.453	13.45%	12.21%	2/27/2013	2.86%
6/21/1984	13.532	13.53%	12.20%	2/28/2013	2.86%
6/20/1984	13.479	13.48%	12.19%	3/1/2013	2.86%
6/19/1984	13.273	13.27%	12.19%	3/4/2013	2.86%
6/18/1984	13.136	13.14%	12.18%	3/5/2013	2.86%
6/15/1984	13.124	13.12%	12.17%	3/6/2013	2.86%
6/14/1984	13.205	13.21%	12.16%	3/7/2013	2.87%
6/13/1984	13.299	13.30%	12.15%	3/8/2013	2.87%
6/12/1984	13.376	13.38%	12.14%	3/11/2013	2.87%
6/11/1984	13.428	13.43%	12.14%	3/12/2013	2.88%
6/8/1984	13.342	13.34%	12.13%	3/13/2013	2.88%
6/7/1984	13.403	13.40%	12.12%	3/14/2013	2.88%
6/6/1984	13.455	13.46%	12.11%	3/15/2013	2.88%
6/5/1984	13.343	13.34%	12.10%	3/18/2013	2.89%
6/4/1984	13.275	13.28%	12.09%	3/19/2013	2.89%
6/1/1984	13.534	13.53%	12.09%	3/20/2013	2.89%
5/31/1984	13.735	13.74%	12.08%	3/21/2013	2.89%
5/30/1984	13.904	13.90%	12.07%	3/22/2013	2.90%
5/29/1984	13.831	13.83%	12.06%	3/25/2013	2.90%
5/25/1984	13.695	13.70%	12.05%	3/26/2013	2.90%
5/24/1984	13.722	13.72%	12.04%	3/27/2013	2.90%
5/23/1984	13.597	13.60%	12.03%	3/28/2013	2.90%

5/22/1984	13.474	13.47%	12.02%	3/29/2013	2.91%
5/21/1984	13.466	13.47%	12.01%	4/1/2013	2.91%
5/18/1984	13.458	13.46%	12.01%	4/2/2013	2.91%
5/17/1984	13.616	13.62%	12.00%	4/3/2013	2.91%
5/16/1984	13.44	13.44%	11.98%	4/4/2013	2.91%
5/15/1984	13.467	13.47%	11.97%	4/5/2013	2.91%
5/14/1984	13.625	13.63%	11.97%	4/8/2013	2.91%
5/11/1984	13.432	13.43%	11.95%	4/9/2013	2.92%
5/10/1984	13.406	13.41%	11.94%	4/10/2013	2.92%
5/9/1984	13.223	13.22%	11.93%	4/11/2013	2.92%
5/8/1984	13.085	13.09%	11.92%	4/12/2013	2.92%
5/7/1984	13.167	13.17%	11.91%	4/15/2013	2.92%
5/4/1984	13.067	13.07%	11.91%	4/16/2013	2.92%
5/3/1984	12.906	12.91%	11.90%	4/17/2013	2.92%
5/2/1984	12.889	12.89%	11.89%	4/18/2013	2.92%
5/1/1984	12.876	12.88%	11.88%	4/19/2013	2.93%
4/30/1984	12.836	12.84%	11.87%	4/22/2013	2.93%
4/27/1984	12.78	12.78%	11.87%	4/23/2013	2.93%
4/26/1984	12.728	12.73%	11.86%	4/24/2013	2.93%
4/25/1984	12.693	12.69%	11.85%	4/25/2013	2.93%
4/24/1984	12.767	12.77%	11.84%	4/26/2013	2.93%
4/23/1984	12.81	12.81%	11.83%	4/29/2013	2.94%
4/19/1984	12.767	12.77%	11.83%	4/30/2013	2.94%
4/18/1984	12.732	12.73%	11.82%	5/1/2013	2.94%
4/17/1984	12.596	12.60%	11.81%	5/2/2013	2.94%
4/16/1984	12.613	12.61%	11.80%	5/3/2013	2.94%
4/13/1984	12.588	12.59%	11.79%	5/6/2013	2.94%
4/12/1984	12.38	12.38%	11.78%	5/7/2013	2.95%
4/11/1984	12.487	12.49%	11.78%	5/8/2013	2.95%
4/10/1984	12.52	12.52%	11.77%	5/9/2013	2.95%
4/9/1984	12.479	12.48%	11.76%	5/10/2013	2.95%
4/6/1984	12.512	12.51%	11.75%	5/13/2013	2.96%
4/5/1984	12.596	12.60%	11.74%	5/14/2013	2.96%
4/4/1984	12.639	12.64%	11.73%	5/15/2013	2.96%
4/3/1984	12.63	12.63%	11.72%	5/16/2013	2.96%
4/2/1984	12.55	12.55%	11.71%	5/17/2013	2.96%
3/30/1984	12.479	12.48%	11.71%	5/20/2013	2.97%
3/29/1984	12.504	12.50%	11.70%	5/21/2013	2.97%
3/28/1984	12.397	12.40%	11.69%	5/22/2013	2.97%
3/27/1984	12.48	12.48%	11.68%	5/23/2013	2.97%
3/26/1984	12.455	12.46%	11.68%	5/24/2013	2.97%
3/23/1984	12.497	12.50%	11.67%	5/27/2013	2.97%
3/22/1984	12.497	12.50%	11.66%	5/28/2013	2.97%
3/21/1984	12.555	12.56%	11.65%	5/29/2013	2.98%
3/20/1984	12.53	12.53%	11.64%	5/30/2013	2.98%
3/19/1984	12.539	12.54%	11.63%	5/31/2013	2.98%
3/16/1984	12.431	12.43%	11.63%	6/3/2013	2.98%

3/15/1984	12.276	12.28%	11.62%	6/4/2013	2.99%
3/14/1984	12.398	12.40%	11.61%	6/5/2013	2.99%
3/13/1984	12.39	12.39%	11.60%	6/6/2013	2.99%
3/12/1984	12.317	12.32%	11.59%	6/7/2013	3.00%
3/9/1984	12.341	12.34%	11.58%	6/10/2013	3.00%
3/8/1984	12.366	12.37%	11.57%	6/11/2013	3.00%
3/7/1984	12.309	12.31%	11.57%	6/12/2013	3.01%
3/6/1984	12.204	12.20%	11.56%	6/13/2013	3.01%
3/5/1984	12.173	12.17%	11.55%	6/14/2013	3.01%
3/2/1984	12.063	12.06%	11.54%	6/17/2013	3.01%
3/1/1984	12.102	12.10%	11.53%	6/18/2013	3.02%
2/29/1984	12.173	12.17%	11.52%	6/19/2013	3.02%
2/28/1984	12.189	12.19%	11.51%	6/20/2013	3.02%
2/27/1984	12.165	12.17%	11.50%	6/21/2013	3.02%
2/24/1984	12.095	12.10%	11.49%	6/24/2013	3.03%
2/23/1984	12.134	12.13%	11.48%	6/25/2013	3.03%
2/22/1984	12.071	12.07%	11.47%	6/26/2013	3.03%
2/21/1984	12.017	12.02%	11.47%	6/27/2013	3.04%
2/17/1984	12.01	12.01%	11.46%	6/28/2013	3.04%
2/16/1984	11.946	11.95%	11.45%	7/1/2013	3.04%
2/15/1984	11.915	11.92%	11.44%	7/2/2013	3.04%
2/14/1984	11.931	11.93%	11.44%	7/3/2013	3.05%
2/10/1984	11.914	11.91%	11.43%	7/4/2013	3.05%
2/9/1984	11.836	11.84%	11.42%	7/5/2013	3.06%
2/8/1984	11.813	11.81%	11.41%	7/8/2013	3.06%
2/7/1984	11.782	11.78%	11.41%	7/9/2013	3.06%
2/6/1984	11.766	11.77%	11.40%	7/10/2013	3.07%
2/3/1984	11.72	11.72%	11.39%	7/11/2013	3.07%
2/2/1984	11.697	11.70%	11.39%	7/12/2013	3.07%
2/1/1984	11.712	11.71%	11.38%	7/15/2013	3.08%
1/31/1984	11.75	11.75%	11.37%	7/16/2013	3.08%
1/30/1984	11.719	11.72%	11.37%	7/17/2013	3.08%
1/27/1984	11.673	11.67%	11.36%	7/18/2013	3.09%
1/26/1984	11.689	11.69%	11.36%	7/19/2013	3.09%
1/25/1984	11.704	11.70%	11.35%	7/22/2013	3.10%
1/24/1984	11.681	11.68%	11.35%	7/23/2013	3.10%
1/23/1984	11.666	11.67%	11.34%	7/24/2013	3.10%
1/20/1984	11.681	11.68%	11.34%	7/25/2013	3.11%
1/19/1984	11.643	11.64%	11.33%	7/26/2013	3.11%
1/18/1984	11.673	11.67%	11.33%	7/29/2013	3.11%
1/17/1984	11.627	11.63%	11.32%	7/30/2013	3.12%
1/16/1984	11.59	11.59%	11.32%	7/31/2013	3.12%
1/13/1984	11.635	11.64%	11.31%	8/1/2013	3.12%
1/12/1984	11.803	11.80%	11.31%	8/2/2013	3.13%
1/11/1984	11.795	11.80%	11.30%	8/5/2013	3.13%
1/10/1984	11.779	11.78%	11.30%	8/6/2013	3.14%
1/9/1984	11.802	11.80%	11.29%	8/7/2013	3.14%

1/6/1984	11.849	11.85%	11.28%	8/8/2013	3.14%
1/5/1984	11.833	11.83%	11.28%	8/9/2013	3.15%
1/4/1984	11.833	11.83%	11.27%	8/12/2013	3.15%
1/3/1984	11.911	11.91%	11.27%	8/13/2013	3.16%
12/30/1983	11.872	11.87%	11.26%	8/14/2013	3.16%
12/29/1983	11.833	11.83%	11.26%	8/15/2013	3.17%
12/28/1983	11.817	11.82%	11.25%	8/16/2013	3.17%
12/27/1983	11.779	11.78%	11.24%	8/19/2013	3.18%
12/23/1983	11.84	11.84%	11.24%	8/20/2013	3.18%
12/22/1983	11.832	11.83%	11.23%	8/21/2013	3.19%
12/21/1983	11.887	11.89%	11.22%	8/22/2013	3.19%
12/20/1983	11.966	11.97%	11.22%	8/23/2013	3.20%
12/19/1983	11.903	11.90%	11.21%	8/26/2013	3.20%
12/16/1983	11.957	11.96%	11.20%	8/27/2013	3.21%
12/15/1983	11.981	11.98%	11.19%	8/28/2013	3.21%
12/14/1983	12.024	12.02%	11.19%	8/29/2013	3.22%
12/13/1983	11.981	11.98%	11.18%	8/30/2013	3.22%
12/12/1983	11.926	11.93%	11.17%	9/2/2013	3.23%
12/9/1983	11.887	11.89%	11.17%	9/3/2013	3.23%
12/8/1983	11.91	11.91%	11.16%	9/4/2013	3.24%
12/7/1983	11.816	11.82%	11.16%	9/5/2013	3.24%
12/6/1983	11.793	11.79%	11.15%	9/6/2013	3.25%
12/5/1983	11.77	11.77%	11.15%	9/9/2013	3.25%
12/2/1983	11.801	11.80%	11.15%	9/10/2013	3.26%
12/1/1983	11.656	11.66%	11.14%	9/11/2013	3.26%
11/30/1983	11.64	11.64%	11.14%	9/12/2013	3.27%
11/29/1983	11.61	11.61%	11.14%	9/13/2013	3.27%
11/28/1983	11.663	11.66%	11.13%	9/16/2013	3.28%
11/25/1983	11.61	11.61%	11.13%	9/17/2013	3.28%
11/23/1983	11.633	11.63%	11.13%	9/18/2013	3.29%
11/22/1983	11.625	11.63%	11.13%	9/19/2013	3.29%
11/21/1983	11.678	11.68%	11.12%	9/20/2013	3.30%
11/18/1983	11.724	11.72%	11.12%	9/23/2013	3.30%
11/17/1983	11.77	11.77%	11.11%	9/24/2013	3.31%
11/16/1983	11.724	11.72%	11.11%	9/25/2013	3.31%
11/15/1983	11.716	11.72%	11.11%	9/26/2013	3.31%
11/14/1983	11.701	11.70%	11.10%	9/27/2013	3.32%
11/10/1983	11.671	11.67%	11.10%	9/30/2013	3.32%
11/9/1983	11.863	11.86%	11.09%	10/1/2013	3.32%
11/7/1983	11.871	11.87%	11.09%	10/2/2013	3.33%
11/4/1983	11.91	11.91%	11.08%	10/3/2013	3.33%
11/3/1983	11.824	11.82%	11.07%	10/4/2013	3.34%
11/2/1983	11.747	11.75%	11.07%	10/7/2013	3.34%
11/1/1983	11.755	11.76%	11.06%	10/8/2013	3.34%
10/31/1983	11.793	11.79%	11.05%	10/9/2013	3.35%
10/28/1983	11.717	11.72%	11.05%	10/10/2013	3.35%
10/27/1983	11.694	11.69%	11.04%	10/11/2013	3.35%

10/26/1983	11.755	11.76%	11.04%	10/14/2013	3.36%
10/25/1983	11.717	11.72%	11.03%	10/15/2013	3.36%
10/24/1983	11.679	11.68%	11.02%	10/16/2013	3.36%
10/21/1983	11.611	11.61%	11.02%	10/17/2013	3.37%
10/20/1983	11.484	11.48%	11.01%	10/18/2013	3.37%
10/19/1983	11.499	11.50%	11.01%	10/21/2013	3.37%
10/18/1983	11.536	11.54%	11.00%	10/22/2013	3.37%
10/17/1983	11.492	11.49%	11.00%	10/23/2013	3.38%
10/14/1983	11.499	11.50%	10.99%	10/24/2013	3.38%
10/13/1983	11.656	11.66%	10.99%	10/25/2013	3.38%
10/12/1983	11.596	11.60%	10.98%	10/28/2013	3.39%
10/11/1983	11.581	11.58%	10.97%	10/29/2013	3.39%
10/7/1983	11.397	11.40%	10.97%	10/30/2013	3.39%
10/6/1983	11.303	11.30%	10.96%	10/31/2013	3.40%
10/5/1983	11.346	11.35%	10.96%	11/1/2013	3.40%
10/4/1983	11.397	11.40%	10.96%	11/4/2013	3.40%
10/3/1983	11.434	11.43%	10.95%	11/5/2013	3.40%
9/30/1983	11.405	11.41%	10.95%	11/6/2013	3.41%
9/29/1983	11.434	11.43%	10.95%	11/7/2013	3.41%
9/28/1983	11.463	11.46%	10.94%	11/8/2013	3.41%
9/27/1983	11.405	11.41%	10.94%	11/11/2013	3.42%
9/26/1983	11.412	11.41%	10.93%	11/12/2013	3.42%
9/23/1983	11.391	11.39%	10.93%	11/13/2013	3.42%
9/22/1983	11.486	11.49%	10.92%	11/14/2013	3.43%
9/21/1983	11.628	11.63%	10.92%	11/15/2013	3.43%
9/20/1983	11.538	11.54%	10.91%	11/18/2013	3.43%
9/19/1983	11.613	11.61%	10.91%	11/19/2013	3.43%
9/16/1983	11.727	11.73%	10.90%	11/20/2013	3.44%
9/15/1983	11.734	11.73%	10.90%	11/21/2013	3.44%
9/14/1983	11.734	11.73%	10.89%	11/22/2013	3.44%
9/13/1983	11.628	11.63%	10.89%	11/25/2013	3.45%
9/12/1983	11.558	11.56%	10.88%	11/26/2013	3.45%
9/9/1983	11.479	11.48%	10.88%	11/27/2013	3.45%
9/8/1983	11.705	11.71%	10.87%	11/28/2013	3.46%
9/7/1983	11.697	11.70%	10.86%	11/29/2013	3.46%
9/6/1983	11.824	11.82%	10.86%	12/2/2013	3.46%
9/1/1983	11.954	11.95%	10.85%	12/3/2013	3.47%
8/31/1983	11.931	11.93%	10.84%	12/4/2013	3.47%
8/30/1983	11.901	11.90%	10.84%	12/5/2013	3.48%
8/29/1983	11.78	11.78%	10.83%	12/6/2013	3.48%
8/26/1983	11.698	11.70%	10.82%	12/9/2013	3.48%
8/25/1983	11.61	11.61%	10.82%	12/10/2013	3.49%
8/24/1983	11.516	11.52%	10.81%	12/11/2013	3.49%
8/23/1983	11.531	11.53%	10.81%	12/12/2013	3.50%
8/22/1983	11.538	11.54%	10.80%	12/13/2013	3.50%
8/19/1983	11.596	11.60%	10.80%	12/16/2013	3.50%
8/18/1983	11.662	11.66%	10.79%	12/17/2013	3.51%

8/17/1983	11.56	11.56%	10.79%	12/18/2013	3.51%
8/16/1983	11.722	11.72%	10.79%	12/19/2013	3.51%
8/15/1983	11.744	11.74%	10.79%	12/20/2013	3.52%
8/12/1983	11.566	11.57%	10.78%	12/23/2013	3.52%
8/11/1983	11.836	11.84%	10.78%	12/24/2013	3.52%
8/10/1983	11.975	11.98%	10.78%	12/25/2013	3.53%
8/9/1983	11.975	11.98%	10.77%	12/26/2013	3.53%
8/8/1983	12.019	12.02%	10.77%	12/27/2013	3.53%
8/5/1983	11.966	11.97%	10.76%	12/30/2013	3.54%
8/4/1983	11.94	11.94%	10.76%	12/31/2013	3.54%
8/2/1983	11.767	11.77%	10.75%	1/1/2014	3.55%
8/1/1983	11.818	11.82%	10.75%	1/2/2014	3.55%
7/29/1983	11.823	11.82%	10.74%	1/3/2014	3.55%
7/28/1983	11.674	11.67%	10.74%	1/6/2014	3.56%
7/27/1983	11.525	11.53%	10.73%	1/7/2014	3.56%
7/26/1983	11.509	11.51%	10.73%	1/8/2014	3.57%
7/25/1983	11.411	11.41%	10.73%	1/9/2014	3.57%
7/22/1983	11.599	11.60%	10.74%	1/10/2014	3.58%
7/21/1983	11.332	11.33%	10.74%	1/13/2014	3.58%
7/20/1983	11.292	11.29%	10.74%	1/14/2014	3.58%
7/19/1983	11.284	11.28%	10.74%	1/15/2014	3.59%
7/18/1983	11.324	11.32%	10.74%	1/16/2014	3.59%
7/15/1983	11.412	11.41%	10.75%	1/17/2014	3.60%
7/14/1983	11.364	11.36%	10.75%	1/20/2014	3.60%
7/13/1983	11.388	11.39%	10.75%	1/21/2014	3.60%
7/12/1983	11.42	11.42%	10.75%	1/22/2014	3.61%
7/11/1983	11.292	11.29%	10.75%	1/23/2014	3.61%
7/8/1983	11.268	11.27%	10.76%	1/24/2014	3.62%
7/7/1983	11.308	11.31%	10.76%	1/27/2014	3.62%
7/6/1983	11.167	11.17%	10.77%	1/28/2014	3.62%
7/5/1983	11.245	11.25%	10.77%	1/29/2014	3.63%
7/1/1983	11.113	11.11%	10.78%	1/30/2014	3.63%
6/30/1983	10.976	10.98%	10.78%	1/31/2014	3.64%
6/29/1983	11.052	11.05%	10.79%	2/3/2014	3.64%
6/28/1983	11.083	11.08%	10.79%	2/4/2014	3.64%
6/27/1983	11.152	11.15%	10.80%	2/5/2014	3.65%
6/24/1983	10.999	11.00%	10.81%	2/6/2014	3.65%
6/23/1983	10.947	10.95%	10.81%	2/7/2014	3.65%
6/22/1983	10.917	10.92%	10.82%	2/10/2014	3.66%
6/21/1983	10.828	10.83%	10.82%	2/11/2014	3.66%
6/20/1983	10.835	10.84%	10.83%	2/12/2014	3.67%
6/17/1983	10.762	10.76%	10.84%	2/13/2014	3.67%
6/16/1983	10.726	10.73%	10.85%	2/14/2014	3.67%
6/15/1983	10.748	10.75%	10.86%	2/17/2014	3.67%
6/14/1983	10.85	10.85%	10.87%	2/18/2014	3.68%
6/13/1983	10.806	10.81%	10.87%	2/19/2014	3.68%
6/10/1983	10.851	10.85%	10.88%	2/20/2014	3.68%

6/9/1983	10.94	10.94%	10.89%	2/21/2014	3.69%
6/8/1983	10.962	10.96%	10.89%	2/24/2014	3.69%
6/7/1983	10.932	10.93%	10.90%	2/25/2014	3.69%
6/6/1983	10.88	10.88%	10.91%	2/26/2014	3.69%
6/3/1983	10.94	10.94%	10.92%	2/27/2014	3.69%
6/2/1983	10.91	10.91%	10.93%	2/28/2014	3.70%
6/1/1983	10.873	10.87%	10.94%	3/3/2014	3.70%
5/31/1983	10.955	10.96%	10.95%	3/4/2014	3.70%
5/27/1983	10.782	10.78%	10.96%	3/5/2014	3.70%
5/26/1983	10.762	10.76%	10.97%	3/6/2014	3.70%
5/25/1983	10.712	10.71%	10.98%	3/7/2014	3.71%
5/24/1983	10.692	10.69%	11.00%	3/10/2014	3.71%
5/23/1983	10.712	10.71%	11.01%	3/11/2014	3.71%
5/20/1983	10.692	10.69%	11.02%	3/12/2014	3.71%
5/19/1983	10.672	10.67%	11.04%	3/13/2014	3.71%
5/18/1983	10.602	10.60%	11.05%	3/14/2014	3.72%
5/17/1983	10.582	10.58%	11.06%	3/17/2014	3.72%
5/16/1983	10.542	10.54%	11.08%	3/18/2014	3.72%
5/13/1983	10.372	10.37%	11.09%	3/19/2014	3.72%
5/12/1983	10.402	10.40%	11.11%	3/20/2014	3.72%
5/11/1983	10.332	10.33%	11.12%	3/21/2014	3.72%
5/10/1983	10.302	10.30%	11.14%	3/24/2014	3.72%
5/9/1983	10.372	10.37%	11.15%	3/25/2014	3.73%
5/6/1983	10.282	10.28%	11.17%	3/26/2014	3.73%
5/5/1983	10.302	10.30%	11.18%	3/27/2014	3.73%
5/4/1983	10.272	10.27%	11.20%	3/28/2014	3.73%
5/3/1983	10.382	10.38%	11.21%	3/31/2014	3.73%
5/2/1983	10.392	10.39%	11.23%	4/1/2014	3.73%
4/29/1983	10.382	10.38%	11.24%	4/2/2014	3.73%
4/28/1983	10.412	10.41%	11.26%	4/3/2014	3.73%
4/27/1983	10.432	10.43%	11.28%	4/4/2014	3.73%
4/26/1983	10.472	10.47%	11.29%	4/7/2014	3.73%
4/25/1983	10.482	10.48%	11.31%	4/8/2014	3.73%
4/22/1983	10.522	10.52%	11.33%	4/9/2014	3.73%
4/21/1983	10.532	10.53%	11.34%	4/10/2014	3.73%
4/20/1983	10.482	10.48%	11.36%	4/11/2014	3.73%
4/19/1983	10.462	10.46%	11.38%	4/14/2014	3.73%
4/18/1983	10.352	10.35%	11.39%	4/15/2014	3.73%
4/15/1983	10.402	10.40%	11.41%	4/16/2014	3.72%
4/14/1983	10.372	10.37%	11.43%	4/17/2014	3.72%
4/13/1983	10.442	10.44%	11.45%	4/18/2014	3.72%
4/12/1983	10.462	10.46%	11.47%	4/21/2014	3.72%
4/11/1983	10.462	10.46%	11.49%	4/22/2014	3.72%
4/8/1983	10.582	10.58%	11.51%	4/23/2014	3.72%
4/7/1983	10.562	10.56%	11.53%	4/24/2014	3.72%
4/6/1983	10.542	10.54%	11.54%	4/25/2014	3.72%
4/5/1983	10.552	10.55%	11.56%	4/28/2014	3.72%

4/4/1983	10.672	10.67%	11.58%	4/29/2014	3.72%
3/31/1983	10.692	10.69%	11.59%	4/30/2014	3.72%
3/30/1983	10.652	10.65%	11.61%	5/1/2014	3.72%
3/29/1983	10.662	10.66%	11.63%	5/2/2014	3.72%
3/28/1983	10.712	10.71%	11.64%	5/5/2014	3.72%
3/25/1983	10.702	10.70%	11.66%	5/6/2014	3.71%
3/24/1983	10.612	10.61%	11.67%	5/7/2014	3.71%
3/23/1983	10.642	10.64%	11.69%	5/8/2014	3.71%
3/22/1983	10.712	10.71%	11.70%	5/9/2014	3.71%
3/21/1983	10.712	10.71%	11.72%	5/12/2014	3.71%
3/18/1983	10.712	10.71%	11.73%	5/13/2014	3.71%
3/17/1983	10.682	10.68%	11.75%	5/14/2014	3.71%
3/16/1983	10.682	10.68%	11.76%	5/15/2014	3.70%
3/15/1983	10.622	10.62%	11.77%	5/16/2014	3.70%
3/14/1983	10.662	10.66%	11.79%	5/19/2014	3.70%
3/11/1983	10.752	10.75%	11.80%	5/20/2014	3.70%
3/10/1983	10.672	10.67%	11.81%	5/21/2014	3.70%
3/9/1983	10.642	10.64%	11.82%	5/22/2014	3.70%
3/8/1983	10.652	10.65%	11.84%	5/23/2014	3.69%
3/7/1983	10.592	10.59%	11.85%	5/26/2014	3.69%
3/4/1983	10.462	10.46%	11.86%	5/27/2014	3.69%
3/3/1983	10.442	10.44%	11.88%	5/28/2014	3.69%
3/2/1983	10.482	10.48%	11.89%	5/29/2014	3.68%
3/1/1983	10.452	10.45%	11.91%	5/30/2014	3.68%
2/28/1983	10.512	10.51%	11.92%	6/2/2014	3.68%
2/25/1983	10.502	10.50%	11.93%	6/3/2014	3.68%
2/24/1983	10.612	10.61%	11.95%	6/4/2014	3.68%
2/23/1983	10.622	10.62%	11.96%	6/5/2014	3.67%
2/22/1983	10.632	10.63%	11.97%	6/6/2014	3.67%
2/18/1983	10.782	10.78%	11.98%	6/9/2014	3.67%
2/17/1983	10.862	10.86%	12.00%	6/10/2014	3.67%
2/16/1983	10.952	10.95%	12.01%	6/11/2014	3.67%
2/15/1983	10.992	10.99%	12.02%	6/12/2014	3.67%
2/14/1983	10.952	10.95%	12.03%	6/13/2014	3.66%
2/11/1983	10.942	10.94%	12.05%	6/16/2014	3.66%
2/10/1983	10.962	10.96%	12.06%	6/17/2014	3.66%
2/9/1983	11.142	11.14%	12.07%	6/18/2014	3.66%
2/8/1983	11.122	11.12%	12.08%	6/19/2014	3.66%
2/7/1983	11.102	11.10%	12.09%	6/20/2014	3.65%
2/4/1983	11.122	11.12%	12.10%	6/23/2014	3.65%
2/3/1983	11.062	11.06%	12.11%	6/24/2014	3.65%
2/2/1983	10.942	10.94%	12.12%	6/25/2014	3.65%
2/1/1983	10.952	10.95%	12.13%	6/26/2014	3.64%
1/31/1983	10.992	10.99%	12.14%	6/27/2014	3.64%
1/28/1983	10.902	10.90%	12.16%	6/30/2014	3.64%
1/27/1983	10.852	10.85%	12.17%	7/1/2014	3.64%
1/26/1983	10.922	10.92%	12.18%	7/2/2014	3.64%

1/25/1983	10.822	10.82%	12.19%	7/3/2014	3.64%
1/24/1983	10.882	10.88%	12.21%	7/4/2014	3.64%
1/21/1983	10.782	10.78%	12.22%	7/7/2014	3.64%
1/20/1983	10.662	10.66%	12.24%	7/8/2014	3.63%
1/19/1983	10.672	10.67%	12.25%	7/9/2014	3.63%
1/18/1983	10.562	10.56%	12.27%	7/10/2014	3.63%
1/17/1983	10.502	10.50%	12.28%	7/11/2014	3.63%
1/14/1983	10.502	10.50%	12.30%	7/14/2014	3.63%
1/13/1983	10.452	10.45%	12.31%	7/15/2014	3.63%
1/12/1983	10.462	10.46%	12.33%	7/16/2014	3.62%
1/11/1983	10.482	10.48%	12.34%	7/17/2014	3.62%
1/10/1983	10.512	10.51%	12.36%	7/18/2014	3.62%
1/7/1983	10.502	10.50%	12.37%	7/21/2014	3.62%
1/6/1983	10.502	10.50%	12.39%	7/22/2014	3.61%
1/5/1983	10.472	10.47%	12.40%	7/23/2014	3.61%
1/4/1983	10.452	10.45%	12.42%	7/24/2014	3.61%
1/3/1983	10.392	10.39%	12.43%	7/25/2014	3.61%
12/31/1982	10.432	10.43%	12.45%	7/28/2014	3.61%
12/30/1982	10.462	10.46%	12.47%	7/29/2014	3.60%
12/29/1982	10.492	10.49%	12.48%	7/30/2014	3.60%
12/28/1982	10.432	10.43%	12.50%	7/31/2014	3.60%
12/27/1982	10.442	10.44%	12.51%	8/1/2014	3.60%
12/23/1982	10.502	10.50%	12.53%	8/4/2014	3.60%
12/22/1982	10.552	10.55%	12.54%	8/5/2014	3.60%
12/21/1982	10.532	10.53%	12.56%	8/6/2014	3.59%
12/20/1982	10.772	10.77%	12.57%	8/7/2014	3.59%
12/17/1982	10.692	10.69%	12.58%	8/8/2014	3.59%
12/16/1982	10.662	10.66%	12.60%	8/11/2014	3.59%
12/15/1982	10.552	10.55%	12.61%	8/12/2014	3.58%
12/14/1982	10.482	10.48%	12.63%	8/13/2014	3.58%
12/13/1982	10.572	10.57%	12.65%	8/14/2014	3.58%
12/10/1982	10.632	10.63%	12.66%	8/15/2014	3.58%
12/9/1982	10.522	10.52%	12.68%	8/18/2014	3.57%
12/8/1982	10.542	10.54%	12.69%	8/19/2014	3.57%
12/7/1982	10.452	10.45%	12.71%	8/20/2014	3.57%
12/6/1982	10.412	10.41%	12.73%	8/21/2014	3.56%
12/3/1982	10.442	10.44%	12.75%	8/22/2014	3.56%
12/2/1982	10.632	10.63%	12.77%	8/25/2014	3.56%
12/1/1982	10.692	10.69%	12.79%	8/26/2014	3.55%
11/30/1982	10.702	10.70%	12.81%	8/27/2014	3.55%
11/29/1982	10.722	10.72%	12.83%	8/28/2014	3.55%
11/26/1982	10.472	10.47%	12.85%	8/29/2014	3.54%
11/24/1982	10.522	10.52%	12.87%	9/1/2014	3.54%
11/23/1982	10.462	10.46%	12.89%	9/2/2014	3.53%
11/22/1982	10.432	10.43%	12.91%	9/3/2014	3.53%
11/19/1982	10.352	10.35%	12.92%	9/4/2014	3.53%
11/18/1982	10.332	10.33%	12.94%	9/5/2014	3.53%

11/17/1982	10.542	10.54%	12.96%	9/8/2014	3.52%
11/16/1982	10.602	10.60%	12.98%	9/9/2014	3.52%
11/15/1982	10.522	10.52%	13.00%	9/10/2014	3.52%
11/12/1982	10.432	10.43%	13.02%	9/11/2014	3.51%
11/10/1982	10.372	10.37%	13.03%	9/12/2014	3.51%
11/9/1982	10.442	10.44%	13.05%	9/15/2014	3.51%
11/8/1982	10.612	10.61%	13.07%	9/16/2014	3.51%
11/5/1982	10.592	10.59%	13.09%	9/17/2014	3.50%
11/4/1982	10.662	10.66%	13.11%	9/18/2014	3.50%
11/3/1982	10.722	10.72%	13.13%	9/19/2014	3.50%
11/1/1982	10.842	10.84%	13.15%	9/22/2014	3.49%
10/29/1982	11.012	11.01%	13.16%	9/23/2014	3.49%
10/28/1982	11.122	11.12%	13.18%	9/24/2014	3.49%
10/27/1982	11.232	11.23%	13.20%	9/25/2014	3.48%
10/26/1982	11.172	11.17%	13.21%	9/26/2014	3.48%
10/25/1982	11.252	11.25%	13.23%	9/29/2014	3.48%
10/22/1982	11.032	11.03%	13.24%	9/30/2014	3.47%
10/21/1982	10.922	10.92%	13.26%	10/1/2014	3.47%
10/20/1982	10.912	10.91%	13.28%	10/2/2014	3.47%
10/19/1982	10.872	10.87%	13.29%	10/3/2014	3.46%
10/18/1982	10.902	10.90%	13.30%	10/6/2014	3.46%
10/15/1982	11.032	11.03%	13.32%	10/7/2014	3.45%
10/14/1982	10.862	10.86%	13.33%	10/8/2014	3.45%
10/13/1982	10.752	10.75%	13.35%	10/9/2014	3.45%
10/12/1982	10.852	10.85%	13.36%	10/10/2014	3.44%
10/8/1982	11.192	11.19%	13.38%	10/13/2014	3.44%
10/7/1982	11.292	11.29%	13.39%	10/14/2014	3.43%
10/6/1982	11.692	11.69%	13.40%	10/15/2014	3.43%
10/5/1982	11.812	11.81%	13.41%	10/16/2014	3.42%
10/4/1982	11.832	11.83%	13.42%	10/17/2014	3.42%
10/1/1982	11.652	11.65%	13.42%	10/20/2014	3.41%
9/30/1982	11.792	11.79%	13.43%	10/21/2014	3.41%
9/29/1982	11.792	11.79%	13.44%	10/22/2014	3.41%
9/28/1982	11.762	11.76%	13.45%	10/23/2014	3.40%
9/27/1982	11.822	11.82%	13.46%	10/24/2014	3.40%
9/24/1982	11.882	11.88%	13.46%	10/27/2014	3.39%
9/23/1982	11.752	11.75%	13.47%	10/28/2014	3.39%
9/22/1982	11.832	11.83%	13.48%	10/29/2014	3.39%
9/21/1982	11.822	11.82%	13.48%	10/30/2014	3.38%
9/20/1982	12.042	12.04%	13.49%	10/31/2014	3.38%
9/17/1982	12.122	12.12%	13.50%	11/3/2014	3.38%
9/16/1982	12.182	12.18%	13.50%	11/4/2014	3.38%
9/15/1982	12.252	12.25%	13.50%	11/5/2014	3.37%
9/14/1982	12.242	12.24%	13.51%	11/6/2014	3.37%
9/13/1982	12.262	12.26%	13.51%	11/7/2014	3.37%
9/10/1982	12.412	12.41%	13.51%	11/10/2014	3.37%
9/9/1982	12.212	12.21%	13.52%	11/11/2014	3.36%

9/8/1982	12.172	12.17%	13.52%	11/12/2014	3.36%
9/7/1982	12.192	12.19%	13.53%	11/13/2014	3.36%
9/3/1982	12.162	12.16%	13.53%	11/14/2014	3.35%
9/2/1982	12.302	12.30%	13.54%	11/17/2014	3.35%
9/1/1982	12.412	12.41%	13.54%	11/18/2014	3.35%
8/31/1982	12.502	12.50%	13.55%	11/19/2014	3.34%
8/30/1982	12.542	12.54%	13.55%	11/20/2014	3.34%
8/27/1982	12.542	12.54%	13.56%	11/21/2014	3.34%
8/26/1982	12.312	12.31%	13.56%	11/24/2014	3.33%
8/25/1982	12.212	12.21%	13.57%	11/25/2014	3.33%
8/24/1982	12.162	12.16%	13.58%	11/26/2014	3.33%
8/23/1982	12.292	12.29%	13.59%	11/27/2014	3.32%
8/20/1982	12.142	12.14%	13.60%	11/28/2014	3.32%
8/19/1982	12.312	12.31%	13.61%	12/1/2014	3.32%
8/18/1982	12.592	12.59%	13.63%	12/2/2014	3.31%
8/17/1982	12.422	12.42%	13.64%	12/3/2014	3.31%
8/16/1982	12.802	12.80%	13.65%	12/4/2014	3.31%
8/13/1982	12.982	12.98%	13.66%	12/5/2014	3.30%
8/12/1982	13.152	13.15%	13.67%	12/8/2014	3.30%
8/11/1982	13.262	13.26%	13.68%	12/9/2014	3.30%
8/10/1982	13.272	13.27%	13.69%	12/10/2014	3.29%
8/9/1982	13.312	13.31%	13.70%	12/11/2014	3.29%
8/6/1982	13.412	13.41%	13.70%	12/12/2014	3.28%
8/5/1982	13.292	13.29%	13.71%	12/15/2014	3.28%
8/4/1982	13.272	13.27%	13.71%	12/16/2014	3.27%
8/3/1982	13.272	13.27%	13.72%	12/17/2014	3.27%
8/2/1982	13.172	13.17%	13.72%	12/18/2014	3.26%
7/30/1982	13.422	13.42%	13.73%	12/19/2014	3.26%
7/29/1982	13.512	13.51%	13.74%	12/22/2014	3.25%
7/28/1982	13.602	13.60%	13.74%	12/23/2014	3.25%
7/27/1982	13.462	13.46%	13.75%	12/24/2014	3.25%
7/26/1982	13.482	13.48%	13.75%	12/25/2014	3.24%
7/23/1982	13.252	13.25%	13.76%	12/26/2014	3.24%
7/22/1982	13.202	13.20%	13.77%	12/29/2014	3.23%
7/21/1982	13.302	13.30%	13.78%	12/30/2014	3.23%
7/20/1982	13.242	13.24%	13.79%	12/31/2014	3.23%
7/19/1982	13.342	13.34%	13.80%	1/1/2015	3.22%
7/16/1982	13.352	13.35%	13.81%	1/2/2015	3.22%
7/15/1982	13.572	13.57%	13.81%	1/5/2015	3.21%
7/14/1982	13.682	13.68%	13.82%	1/6/2015	3.21%
7/13/1982	13.612	13.61%	13.82%	1/7/2015	3.20%
7/12/1982	13.462	13.46%	13.82%	1/8/2015	3.20%
7/9/1982	13.572	13.57%	13.82%	1/9/2015	3.19%
7/8/1982	13.702	13.70%	13.83%	1/12/2015	3.19%
7/7/1982	13.902	13.90%	13.83%	1/13/2015	3.18%
7/6/1982	14.002	14.00%	13.84%	1/14/2015	3.18%
7/2/1982	14.032	14.03%	13.84%	1/15/2015	3.17%

7/1/1982	13.902	13.90%	13.84%	1/16/2015	3.17%
6/30/1982	13.912	13.91%	13.85%	1/19/2015	3.16%
6/29/1982	14.112	14.11%	13.85%	1/20/2015	3.15%
6/28/1982	14.192	14.19%	13.85%	1/21/2015	3.15%
6/25/1982	14.242	14.24%	13.86%	1/22/2015	3.14%
6/24/1982	14.202	14.20%	13.86%	1/23/2015	3.14%
6/23/1982	14.262	14.26%	13.86%	1/26/2015	3.13%
6/22/1982	14.212	14.21%	13.86%	1/27/2015	3.13%
6/21/1982	14.152	14.15%	13.87%	1/28/2015	3.12%
6/18/1982	14.192	14.19%	13.87%	1/29/2015	3.12%
6/17/1982	14.102	14.10%	13.87%	1/30/2015	3.11%
6/16/1982	13.912	13.91%	13.87%	2/2/2015	3.10%
6/15/1982	13.872	13.87%	13.88%	2/3/2015	3.10%
6/14/1982	13.892	13.89%	13.88%	2/4/2015	3.09%
6/11/1982	13.612	13.61%	13.88%	2/5/2015	3.09%
6/10/1982	13.722	13.72%	13.88%	2/6/2015	3.08%
6/9/1982	13.712	13.71%	13.88%	2/9/2015	3.08%
6/8/1982	13.712	13.71%	13.88%	2/10/2015	3.08%
6/7/1982	13.662	13.66%	13.88%	2/11/2015	3.07%
6/4/1982	13.762	13.76%	13.88%	2/12/2015	3.07%
6/3/1982	13.662	13.66%	13.89%	2/13/2015	3.06%
6/2/1982	13.602	13.60%	13.89%	2/16/2015	3.06%
6/1/1982	13.662	13.66%	13.89%	2/17/2015	3.05%
5/28/1982	13.392	13.39%	13.89%	2/18/2015	3.05%
5/27/1982	13.362	13.36%	13.89%	2/19/2015	3.05%
5/26/1982	13.292	13.29%	13.90%	2/20/2015	3.05%
5/25/1982	13.502	13.50%	13.90%	2/23/2015	3.04%
5/24/1982	13.192	13.19%	13.90%	2/24/2015	3.04%
5/21/1982	13.172	13.17%	13.91%	2/25/2015	3.03%
5/20/1982	13.172	13.17%	13.91%	2/26/2015	3.03%
5/19/1982	13.302	13.30%	13.92%	2/27/2015	3.03%
5/18/1982	13.262	13.26%	13.92%	3/2/2015	3.02%
5/17/1982	13.292	13.29%	13.92%	3/3/2015	3.02%
5/14/1982	13.172	13.17%	13.92%	3/4/2015	3.02%
5/13/1982	13.252	13.25%	13.93%	3/5/2015	3.01%
5/12/1982	13.232	13.23%	13.93%	3/6/2015	3.01%
5/11/1982	13.082	13.08%	13.93%	3/9/2015	3.01%
5/10/1982	13.132	13.13%	13.94%	3/10/2015	3.00%
5/7/1982	13.082	13.08%	13.94%	3/11/2015	3.00%
5/6/1982	13.132	13.13%	13.94%	3/12/2015	3.00%
5/5/1982	13.342	13.34%	13.94%	3/13/2015	2.99%
5/4/1982	13.372	13.37%	13.94%	3/16/2015	2.99%
5/3/1982	13.452	13.45%	13.94%	3/17/2015	2.98%
4/30/1982	13.392	13.39%	13.94%	3/18/2015	2.98%
4/29/1982	13.382	13.38%	13.94%	3/19/2015	2.98%
4/28/1982	13.272	13.27%	13.94%	3/20/2015	2.97%
4/27/1982	13.192	13.19%	13.94%	3/23/2015	2.97%

4/26/1982	13.162	13.16%	13.94%	3/24/2015	2.96%
4/23/1982	13.182	13.18%	13.94%	3/25/2015	2.96%
4/22/1982	13.192	13.19%	13.94%	3/26/2015	2.95%
4/21/1982	13.222	13.22%	13.94%	3/27/2015	2.95%
4/20/1982	13.212	13.21%	13.94%	3/30/2015	2.94%
4/19/1982	13.132	13.13%	13.94%	3/31/2015	2.94%
4/16/1982	13.182	13.18%	13.94%	4/1/2015	2.93%
4/15/1982	13.322	13.32%	13.94%	4/2/2015	2.93%
4/14/1982	13.422	13.42%	13.94%	4/3/2015	2.93%
4/13/1982	13.322	13.32%	13.94%	4/6/2015	2.92%
4/12/1982	13.302	13.30%	13.94%	4/7/2015	2.92%
4/8/1982	13.482	13.48%	13.93%	4/8/2015	2.91%
4/7/1982	13.712	13.71%	13.93%	4/9/2015	2.91%
4/6/1982	13.732	13.73%	13.92%	4/10/2015	2.90%
4/5/1982	13.722	13.72%	13.92%	4/13/2015	2.90%
4/2/1982	13.612	13.61%	13.91%	4/14/2015	2.90%
4/1/1982	13.602	13.60%	13.91%	4/15/2015	2.89%
3/31/1982	13.682	13.68%	13.91%	4/16/2015	2.89%
3/30/1982	13.812	13.81%	13.90%	4/17/2015	2.88%
3/29/1982	13.792	13.79%	13.90%	4/20/2015	2.88%
3/26/1982	13.652	13.65%	13.89%	4/21/2015	2.88%
3/25/1982	13.492	13.49%	13.89%	4/22/2015	2.87%
3/24/1982	13.512	13.51%	13.89%	4/23/2015	2.87%
3/23/1982	13.362	13.36%	13.89%	4/24/2015	2.87%
3/22/1982	13.372	13.37%	13.89%	4/27/2015	2.86%
3/19/1982	13.562	13.56%	13.88%	4/28/2015	2.86%
3/18/1982	13.512	13.51%	13.88%	4/29/2015	2.86%
3/17/1982	13.522	13.52%	13.88%	4/30/2015	2.85%
3/16/1982	13.572	13.57%	13.88%	5/1/2015	2.85%
3/15/1982	13.562	13.56%	13.88%	5/4/2015	2.85%
3/12/1982	13.652	13.65%	13.88%	5/5/2015	2.85%
3/11/1982	13.652	13.65%	13.88%	5/6/2015	2.85%
3/10/1982	13.502	13.50%	13.88%	5/7/2015	2.85%
3/9/1982	13.432	13.43%	13.88%	5/8/2015	2.84%
3/8/1982	13.492	13.49%	13.88%	5/11/2015	2.84%
3/5/1982	13.352	13.35%	13.88%	5/12/2015	2.84%
3/4/1982	13.352	13.35%	13.88%	5/13/2015	2.84%
3/3/1982	13.392	13.39%	13.88%	5/14/2015	2.84%
3/2/1982	13.442	13.44%	13.89%	5/15/2015	2.84%
3/1/1982	13.632	13.63%	13.89%	5/18/2015	2.84%
2/26/1982	13.832	13.83%	13.89%	5/19/2015	2.84%
2/25/1982	13.722	13.72%	13.89%	5/20/2015	2.83%
2/24/1982	13.622	13.62%	13.89%	5/21/2015	2.83%
2/23/1982	13.732	13.73%	13.89%	5/22/2015	2.83%
2/22/1982	13.652	13.65%	13.89%	5/25/2015	2.83%
2/19/1982	14.022	14.02%	13.89%	5/26/2015	2.83%
2/18/1982	14.062	14.06%	13.89%	5/27/2015	2.83%

2/17/1982	14.302	14.30%	13.89%	5/28/2015	2.83%
2/16/1982	14.332	14.33%	13.88%	5/29/2015	2.83%
2/11/1982	14.542	14.54%	13.88%	6/1/2015	2.82%
2/10/1982	14.642	14.64%	13.87%	6/2/2015	2.82%
2/9/1982	14.802	14.80%	13.86%	6/3/2015	2.82%
2/8/1982	14.742	14.74%	13.86%	6/4/2015	2.82%
2/5/1982	14.432	14.43%	13.85%	6/5/2015	2.82%
2/4/1982	14.542	14.54%	13.84%	6/8/2015	2.82%
2/3/1982	14.412	14.41%	13.84%	6/9/2015	2.82%
2/2/1982	14.262	14.26%	13.83%	6/10/2015	2.82%
2/1/1982	14.332	14.33%	13.82%	6/11/2015	2.82%
1/29/1982	13.912	13.91%	13.82%	6/12/2015	2.82%
1/28/1982	13.982	13.98%	13.81%	6/15/2015	2.82%
1/27/1982	14.172	14.17%	13.81%	6/16/2015	2.82%
1/26/1982	14.192	14.19%	13.80%	6/17/2015	2.82%
1/25/1982	14.202	14.20%	13.80%	6/18/2015	2.82%
1/22/1982	14.242	14.24%	13.79%	6/19/2015	2.82%
1/21/1982	14.212	14.21%	13.79%	6/22/2015	2.82%
1/20/1982	14.322	14.32%	13.78%	6/23/2015	2.82%
1/19/1982	14.362	14.36%	13.77%	6/24/2015	2.82%
1/18/1982	14.272	14.27%	13.76%	6/25/2015	2.81%
1/15/1982	14.412	14.41%	13.76%	6/26/2015	2.81%
1/14/1982	14.312	14.31%	13.75%	6/29/2015	2.81%
1/13/1982	14.472	14.47%	13.74%	6/30/2015	2.81%
1/12/1982	14.272	14.27%	13.73%	7/1/2015	2.81%
1/11/1982	14.432	14.43%	13.72%	7/2/2015	2.81%
1/8/1982	14.132	14.13%	13.71%	7/3/2015	2.81%
1/7/1982	14.322	14.32%	13.70%	7/6/2015	2.81%
1/6/1982	14.282	14.28%	13.69%	7/7/2015	2.81%
1/5/1982	14.142	14.14%	13.68%	7/8/2015	2.81%
12/31/1981	13.652	13.65%	13.67%	7/9/2015	2.81%
12/30/1981	13.862	13.86%	13.67%	7/10/2015	2.81%
12/29/1981	13.882	13.88%	13.66%	7/13/2015	2.81%
12/28/1981	13.722	13.72%	13.66%	7/14/2015	2.81%
12/24/1981	13.762	13.76%	13.65%	7/15/2015	2.81%
12/23/1981	13.852	13.85%	13.65%	7/16/2015	2.81%
12/22/1981	13.652	13.65%	13.64%	7/17/2015	2.81%
12/21/1981	13.552	13.55%	13.64%	7/20/2015	2.81%
12/18/1981	13.302	13.30%	13.63%	7/21/2015	2.81%
12/17/1981	13.482	13.48%	13.63%	7/22/2015	2.81%
12/16/1981	13.322	13.32%	13.63%	7/23/2015	2.81%
12/15/1981	13.302	13.30%	13.63%	7/24/2015	2.81%
12/14/1981	13.342	13.34%	13.63%	7/27/2015	2.81%
12/11/1981	13.552	13.55%	13.63%	7/28/2015	2.81%
12/10/1981	13.582	13.58%	13.62%	7/29/2015	2.81%
12/9/1981	13.392	13.39%	13.62%	7/30/2015	2.81%
12/8/1981	13.242	13.24%	13.61%	7/31/2015	2.81%

12/7/1981	13.262	13.26%	13.61%	8/3/2015	2.81%
12/4/1981	12.892	12.89%	13.61%	8/4/2015	2.81%
12/3/1981	13.162	13.16%	13.61%	8/5/2015	2.81%
12/2/1981	13.212	13.21%	13.61%	8/6/2015	2.81%
12/1/1981	13.062	13.06%	13.61%	8/7/2015	2.81%
11/30/1981	12.912	12.91%	13.61%	8/10/2015	2.81%
11/27/1981	12.762	12.76%	13.61%	8/11/2015	2.81%
11/25/1981	12.832	12.83%	13.61%	8/12/2015	2.81%
11/24/1981	13.032	13.03%	13.61%	8/13/2015	2.80%
11/23/1981	13.382	13.38%	13.60%	8/14/2015	2.80%
11/20/1981	13.082	13.08%	13.60%	8/17/2015	2.80%
11/19/1981	13.092	13.09%	13.60%	8/18/2015	2.80%
11/18/1981	13.052	13.05%	13.59%	8/19/2015	2.80%
11/17/1981	13.252	13.25%	13.59%	8/20/2015	2.80%
11/16/1981	13.112	13.11%	13.59%	8/21/2015	2.80%
11/13/1981	13.262	13.26%	13.58%	8/24/2015	2.79%
11/12/1981	13.212	13.21%	13.58%	8/25/2015	2.79%
11/10/1981	13.552	13.55%	13.57%	8/26/2015	2.79%
11/9/1981	13.562	13.56%	13.57%	8/27/2015	2.79%
11/6/1981	13.852	13.85%	13.56%	8/28/2015	2.79%
11/5/1981	14.062	14.06%	13.55%	8/31/2015	2.79%
11/4/1981	13.962	13.96%	13.54%	9/1/2015	2.79%
11/2/1981	14.412	14.41%	13.53%	9/2/2015	2.79%
10/30/1981	14.362	14.36%	13.52%	9/3/2015	2.79%
10/29/1981	14.662	14.66%	13.51%	9/4/2015	2.79%
10/28/1981	15.032	15.03%	13.50%	9/7/2015	2.79%
10/27/1981	15.092	15.09%	13.48%	9/8/2015	2.79%
10/26/1981	15.212	15.21%	13.47%	9/9/2015	2.79%
10/23/1981	14.812	14.81%	13.45%	9/10/2015	2.79%
10/22/1981	14.912	14.91%	13.44%	9/11/2015	2.79%
10/21/1981	14.942	14.94%	13.42%	9/14/2015	2.79%
10/20/1981	14.662	14.66%	13.41%	9/15/2015	2.79%
10/19/1981	14.522	14.52%	13.39%	9/16/2015	2.79%
10/16/1981	14.552	14.55%	13.38%	9/17/2015	2.79%
10/15/1981	14.392	14.39%	13.37%	9/18/2015	2.79%
10/14/1981	14.482	14.48%	13.35%	9/21/2015	2.80%
10/13/1981	14.362	14.36%	13.34%	9/22/2015	2.80%
10/9/1981	14.262	14.26%	13.33%	9/23/2015	2.80%
10/8/1981	14.442	14.44%	13.32%	9/24/2015	2.80%
10/7/1981	14.542	14.54%	13.30%	9/25/2015	2.80%
10/6/1981	14.602	14.60%	13.29%	9/28/2015	2.80%
10/5/1981	14.622	14.62%	13.28%	9/29/2015	2.80%
10/2/1981	14.802	14.80%	13.27%	9/30/2015	2.80%
10/1/1981	15.142	15.14%	13.26%	10/1/2015	2.80%
9/30/1981	15.192	15.19%	13.25%	10/2/2015	2.80%
9/29/1981	15.202	15.20%	13.24%	10/5/2015	2.80%
9/28/1981	15.012	15.01%	13.23%	10/6/2015	2.80%

9/25/1981	15.082	15.08%	13.22%	10/7/2015	2.80%
9/24/1981	14.692	14.69%	13.21%	10/8/2015	2.80%
9/23/1981	14.612	14.61%	13.20%	10/9/2015	2.80%
9/22/1981	14.332	14.33%	13.18%	10/12/2015	2.81%
9/21/1981	14.092	14.09%	13.17%	10/13/2015	2.81%
9/18/1981	14.222	14.22%	13.17%	10/14/2015	2.81%
9/17/1981	14.262	14.26%	13.16%	10/15/2015	2.81%
9/16/1981	14.422	14.42%	13.15%	10/16/2015	2.81%
9/15/1981	14.442	14.44%	13.14%	10/19/2015	2.81%
9/14/1981	14.512	14.51%	13.13%	10/20/2015	2.82%
9/11/1981	14.492	14.49%	13.12%	10/21/2015	2.82%
9/10/1981	14.682	14.68%	13.11%	10/22/2015	2.82%
9/9/1981	14.732	14.73%	13.09%	10/23/2015	2.82%
9/8/1981	14.992	14.99%	13.08%	10/26/2015	2.83%
9/4/1981	14.842	14.84%	13.07%	10/27/2015	2.83%
9/3/1981	14.822	14.82%	13.05%	10/28/2015	2.83%
9/2/1981	14.702	14.70%	13.04%	10/29/2015	2.83%
9/1/1981	14.702	14.70%	13.03%	10/30/2015	2.84%
8/31/1981	14.782	14.78%	13.02%	11/2/2015	2.84%
8/28/1981	14.492	14.49%	13.01%	11/3/2015	2.84%
8/27/1981	14.592	14.59%	13.00%	11/4/2015	2.84%
8/26/1981	14.602	14.60%	12.99%	11/5/2015	2.85%
8/25/1981	14.612	14.61%	12.98%	11/6/2015	2.85%
8/24/1981	14.572	14.57%	12.97%	11/9/2015	2.86%
8/21/1981	14.142	14.14%	12.96%	11/10/2015	2.86%
8/20/1981	14.082	14.08%	12.95%	11/11/2015	2.86%
8/19/1981	13.952	13.95%	12.94%	11/12/2015	2.87%
8/18/1981	13.952	13.95%	12.93%	11/13/2015	2.87%
8/17/1981	13.902	13.90%	12.92%	11/16/2015	2.87%
8/14/1981	13.952	13.95%	12.91%	11/17/2015	2.88%
8/13/1981	13.882	13.88%	12.90%	11/18/2015	2.88%
8/12/1981	13.822	13.82%	12.89%	11/19/2015	2.88%
8/11/1981	13.632	13.63%	12.88%	11/20/2015	2.88%
8/10/1981	13.882	13.88%	12.87%	11/23/2015	2.88%
8/7/1981	14.072	14.07%	12.85%	11/24/2015	2.88%
8/6/1981	14.042	14.04%	12.84%	11/25/2015	2.89%
8/5/1981	14.152	14.15%	12.83%	11/26/2015	2.89%
8/4/1981	14.172	14.17%	12.81%	11/27/2015	2.89%
8/3/1981	14.272	14.27%	12.80%	11/30/2015	2.89%
7/31/1981	13.962	13.96%	12.78%	12/1/2015	2.89%
7/30/1981	13.952	13.95%	12.77%	12/2/2015	2.89%
7/29/1981	13.922	13.92%	12.75%	12/3/2015	2.90%
7/28/1981	13.802	13.80%	12.74%	12/4/2015	2.90%
7/27/1981	13.702	13.70%	12.73%	12/7/2015	2.90%
7/24/1981	13.652	13.65%	12.72%	12/8/2015	2.90%
7/23/1981	13.802	13.80%	12.71%	12/9/2015	2.90%
7/22/1981	13.872	13.87%	12.70%	12/10/2015	2.90%

7/21/1981	13.842	13.84%	12.69%	12/11/2015	2.90%
7/20/1981	13.872	13.87%	12.68%	12/14/2015	2.90%
7/17/1981	13.402	13.40%	12.67%	12/15/2015	2.91%
7/16/1981	13.442	13.44%	12.66%	12/16/2015	2.91%
7/15/1981	13.352	13.35%	12.65%	12/17/2015	2.91%
7/14/1981	13.492	13.49%	12.64%	12/18/2015	2.91%
7/13/1981	13.332	13.33%	12.63%	12/21/2015	2.91%
7/10/1981	13.252	13.25%	12.62%	12/22/2015	2.91%
7/9/1981	13.472	13.47%	12.61%	12/23/2015	2.91%
7/8/1981	13.432	13.43%	12.60%	12/24/2015	2.92%
7/7/1981	13.422	13.42%	12.59%	12/25/2015	2.92%
7/6/1981	13.192	13.19%	12.58%	12/28/2015	2.92%
7/2/1981	13.352	13.35%	12.57%	12/29/2015	2.92%
7/1/1981	13.472	13.47%	12.56%	12/30/2015	2.93%
6/30/1981	13.302	13.30%	12.54%	12/31/2015	2.93%
6/29/1981	13.112	13.11%	12.53%	1/1/2016	2.93%
6/26/1981	13.142	13.14%	12.52%	1/4/2016	2.93%
6/25/1981	13.142	13.14%	12.51%	1/5/2016	2.94%
6/24/1981	13.102	13.10%	12.50%	1/6/2016	2.94%
6/23/1981	12.992	12.99%	12.49%	1/7/2016	2.94%
6/22/1981	12.862	12.86%	12.48%	1/8/2016	2.94%
6/19/1981	12.902	12.90%	12.47%	1/11/2016	2.94%
6/18/1981	12.982	12.98%	12.47%	1/12/2016	2.95%
6/17/1981	12.732	12.73%	12.46%	1/13/2016	2.95%
6/16/1981	12.592	12.59%	12.45%	1/14/2016	2.95%
6/15/1981	12.612	12.61%	12.44%	1/15/2016	2.95%
6/12/1981	12.842	12.84%	12.44%	1/18/2016	2.95%
6/11/1981	12.842	12.84%	12.43%	1/19/2016	2.95%
6/10/1981	12.822	12.82%	12.42%	1/20/2016	2.95%
6/9/1981	12.892	12.89%	12.41%	1/21/2016	2.96%
6/8/1981	12.872	12.87%	12.40%	1/22/2016	2.96%
6/5/1981	13.112	13.11%	12.39%	1/25/2016	2.96%
6/4/1981	13.042	13.04%	12.38%	1/26/2016	2.96%
6/3/1981	13.082	13.08%	12.37%	1/27/2016	2.96%
6/2/1981	13.132	13.13%	12.36%	1/28/2016	2.96%
6/1/1981	13.062	13.06%	12.35%	1/29/2016	2.96%
5/29/1981	13.062	13.06%	12.34%	2/1/2016	2.96%
5/28/1981	13.102	13.10%	12.33%	2/2/2016	2.96%
5/27/1981	13.272	13.27%	12.31%	2/3/2016	2.96%
5/26/1981	13.222	13.22%	12.30%	2/4/2016	2.96%
5/22/1981	13.362	13.36%	12.29%	2/5/2016	2.96%
5/21/1981	13.532	13.53%	12.27%	2/8/2016	2.96%
5/20/1981	13.452	13.45%	12.26%	2/9/2016	2.96%
5/19/1981	13.472	13.47%	12.25%	2/10/2016	2.95%
5/18/1981	13.312	13.31%	12.23%	2/11/2016	2.95%
5/15/1981	13.582	13.58%	12.22%	2/12/2016	2.95%
5/14/1981	13.662	13.66%	12.20%	2/15/2016	2.95%

5/13/1981	13.952	13.95%	12.18%	2/16/2016	2.95%
5/12/1981	13.952	13.95%	12.16%	2/17/2016	2.94%
5/11/1981	13.892	13.89%	12.15%	2/18/2016	2.94%
5/8/1981	13.762	13.76%	12.13%	2/19/2016	2.94%
5/7/1981	13.842	13.84%	12.11%	2/22/2016	2.94%
5/6/1981	13.972	13.97%	12.09%	2/23/2016	2.94%
5/5/1981	14.112	14.11%	12.07%	2/24/2016	2.93%
5/4/1981	13.982	13.98%	12.05%	2/25/2016	2.93%
5/1/1981	13.592	13.59%	12.03%	2/26/2016	2.93%
4/30/1981	13.652	13.65%	12.02%	2/29/2016	2.93%
4/29/1981	13.502	13.50%	12.00%	3/1/2016	2.93%
4/28/1981	13.392	13.39%	11.98%	3/2/2016	2.93%
4/27/1981	13.382	13.38%	11.97%	3/3/2016	2.93%
4/24/1981	13.352	13.35%	11.95%	3/4/2016	2.92%
4/23/1981	13.282	13.28%	11.93%	3/7/2016	2.92%
4/22/1981	13.252	13.25%	11.92%	3/8/2016	2.92%
4/21/1981	13.202	13.20%	11.90%	3/9/2016	2.92%
4/20/1981	13.172	13.17%	11.89%	3/10/2016	2.92%
4/16/1981	13.322	13.32%	11.87%	3/11/2016	2.92%
4/15/1981	13.292	13.29%	11.85%	3/14/2016	2.91%
4/14/1981	13.132	13.13%	11.83%	3/15/2016	2.91%
4/13/1981	13.232	13.23%	11.82%	3/16/2016	2.91%
4/10/1981	13.152	13.15%	11.80%	3/17/2016	2.91%
4/9/1981	13.022	13.02%	11.78%	3/18/2016	2.90%
4/8/1981	13.152	13.15%	11.76%	3/21/2016	2.90%
4/7/1981	12.992	12.99%	11.75%	3/22/2016	2.90%
4/6/1981	13.282	13.28%	11.73%	3/23/2016	2.90%
4/3/1981	12.942	12.94%	11.71%	3/24/2016	2.90%
4/2/1981	12.802	12.80%	11.69%	3/25/2016	2.90%
4/1/1981	12.652	12.65%	11.68%	3/28/2016	2.89%
3/31/1981	12.652	12.65%	11.66%	3/29/2016	2.89%
3/30/1981	12.802	12.80%	11.65%	3/30/2016	2.89%
3/27/1981	12.932	12.93%	11.63%	3/31/2016	2.88%
3/26/1981	12.922	12.92%	11.62%	4/1/2016	2.88%
3/25/1981	12.772	12.77%	11.60%	4/4/2016	2.88%
3/24/1981	12.842	12.84%	11.59%	4/5/2016	2.88%
3/23/1981	12.712	12.71%	11.58%	4/6/2016	2.87%
3/20/1981	12.342	12.34%	11.57%	4/7/2016	2.87%
3/19/1981	12.282	12.28%	11.56%	4/8/2016	2.87%
3/18/1981	12.162	12.16%	11.55%	4/11/2016	2.86%
3/17/1981	12.252	12.25%	11.54%	4/12/2016	2.86%
3/16/1981	12.412	12.41%	11.53%	4/13/2016	2.86%
3/13/1981	12.422	12.42%	11.52%	4/14/2016	2.86%
3/12/1981	12.592	12.59%	11.50%	4/15/2016	2.85%
3/11/1981	12.742	12.74%	11.49%	4/18/2016	2.85%
3/10/1981	12.692	12.69%	11.48%	4/19/2016	2.85%
3/9/1981	12.642	12.64%	11.47%	4/20/2016	2.84%

3/6/1981	12.732	12.73%	11.46%	4/21/2016	2.84%
3/5/1981	13.002	13.00%	11.45%	4/22/2016	2.84%
3/4/1981	13.032	13.03%	11.44%	4/25/2016	2.84%
3/3/1981	13.002	13.00%	11.42%	4/26/2016	2.84%
3/2/1981	13.192	13.19%	11.41%	4/27/2016	2.84%
2/27/1981	12.972	12.97%	11.40%	4/28/2016	2.83%
2/26/1981	12.982	12.98%	11.38%	4/29/2016	2.83%
2/25/1981	12.892	12.89%	11.37%	5/2/2016	2.83%
2/24/1981	12.812	12.81%	11.36%	5/3/2016	2.83%
2/23/1981	12.812	12.81%	11.34%	5/4/2016	2.83%
2/20/1981	12.542	12.54%	11.33%	5/5/2016	2.83%
2/19/1981	12.712	12.71%	11.32%	5/6/2016	2.83%
2/18/1981	12.882	12.88%	11.31%	5/9/2016	2.82%
2/17/1981	12.932	12.93%	11.30%	5/10/2016	2.82%
2/13/1981	13.202	13.20%	11.29%	5/11/2016	2.82%
2/11/1981	13.012	13.01%	11.28%	5/12/2016	2.82%
2/10/1981	12.922	12.92%	11.27%	5/13/2016	2.82%
2/9/1981	12.812	12.81%	11.26%	5/16/2016	2.82%
2/6/1981	12.732	12.73%	11.25%	5/17/2016	2.82%
2/5/1981	12.702	12.70%	11.25%	5/18/2016	2.81%
2/4/1981	12.492	12.49%	11.24%	5/19/2016	2.81%
2/3/1981	12.612	12.61%	11.23%	5/20/2016	2.81%
2/2/1981	12.452	12.45%	11.22%	5/23/2016	2.81%
1/30/1981	12.282	12.28%	11.22%	5/24/2016	2.81%
1/29/1981	12.382	12.38%	11.21%	5/25/2016	2.81%
1/28/1981	12.332	12.33%	11.21%	5/26/2016	2.81%
1/27/1981	12.312	12.31%	11.21%	5/27/2016	2.81%
1/26/1981	12.282	12.28%	11.20%	5/30/2016	2.81%
1/23/1981	12.382	12.38%	11.20%	5/31/2016	2.81%
1/22/1981	12.462	12.46%	11.20%	6/1/2016	2.81%
1/21/1981	12.332	12.33%	11.20%	6/2/2016	2.80%
1/20/1981	12.112	12.11%	11.20%	6/3/2016	2.80%
1/19/1981	12.252	12.25%	11.20%	6/6/2016	2.80%
1/16/1981	12.132	12.13%	11.20%	6/7/2016	2.80%
1/15/1981	12.252	12.25%	11.20%	6/8/2016	2.80%
1/14/1981	12.072	12.07%	11.20%	6/9/2016	2.79%
1/13/1981	12.082	12.08%	11.20%	6/10/2016	2.79%
1/12/1981	12.082	12.08%	11.21%	6/13/2016	2.79%
1/9/1981	12.132	12.13%	11.21%	6/14/2016	2.79%
1/8/1981	11.912	11.91%	11.21%	6/15/2016	2.78%
1/7/1981	11.892	11.89%	11.21%	6/16/2016	2.78%
1/6/1981	11.672	11.67%	11.21%	6/17/2016	2.78%
1/5/1981	11.672	11.67%	11.21%	6/20/2016	2.78%
1/2/1981	12.012	12.01%	11.22%	6/21/2016	2.77%
12/31/1980	11.982	11.98%	11.22%	6/22/2016	2.77%
12/30/1980	11.962	11.96%	11.22%	6/23/2016	2.77%
12/29/1980	11.842	11.84%	11.22%	6/24/2016	2.77%

12/26/1980	11.842	11.84%	11.22%	6/27/2016	2.76%
12/24/1980	11.952	11.95%	11.22%	6/28/2016	2.76%
12/23/1980	11.932	11.93%	11.23%	6/29/2016	2.76%
12/22/1980	11.752	11.75%	11.23%	6/30/2016	2.75%
12/19/1980	12.222	12.22%	11.23%	7/1/2016	2.75%
12/18/1980	12.622	12.62%	11.23%	7/4/2016	2.75%
12/17/1980	12.742	12.74%	11.23%	7/5/2016	2.74%
12/16/1980	12.952	12.95%	11.23%	7/6/2016	2.74%
12/15/1980	12.852	12.85%	11.23%	7/7/2016	2.73%
12/12/1980	12.822	12.82%	11.23%	7/8/2016	2.73%
12/11/1980	13.172	13.17%	11.23%	7/11/2016	2.73%
12/10/1980	12.802	12.80%	11.22%	7/12/2016	2.72%
12/9/1980	12.682	12.68%	11.22%	7/13/2016	2.72%
12/8/1980	12.422	12.42%	11.22%	7/14/2016	2.72%
12/5/1980	12.332	12.33%	11.22%	7/15/2016	2.71%
12/4/1980	12.432	12.43%	11.22%	7/18/2016	2.71%
12/3/1980	12.412	12.41%	11.22%	7/19/2016	2.71%
12/2/1980	12.502	12.50%	11.22%	7/20/2016	2.70%
12/1/1980	12.512	12.51%	11.22%	7/21/2016	2.70%
11/28/1980	12.32	12.32%	11.21%	7/22/2016	2.70%
11/26/1980	12.27	12.27%	11.21%	7/25/2016	2.70%
11/25/1980	12.3	12.30%	11.21%	7/26/2016	2.69%
11/24/1980	12.31	12.31%	11.21%	7/27/2016	2.69%
11/21/1980	12.37	12.37%	11.20%	7/28/2016	2.69%
11/20/1980	12.22	12.22%	11.20%	7/29/2016	2.68%
11/19/1980	12.19	12.19%	11.19%	8/1/2016	2.68%
11/18/1980	12.29	12.29%	11.19%	8/2/2016	2.68%
11/17/1980	12.6	12.60%	11.18%	8/3/2016	2.67%
11/14/1980	12.45	12.45%	11.17%	8/4/2016	2.67%
11/13/1980	12.23	12.23%	11.17%	8/5/2016	2.67%
11/12/1980	12.26	12.26%	11.16%	8/8/2016	2.66%
11/10/1980	12.71	12.71%	11.15%	8/9/2016	2.66%
11/7/1980	12.59	12.59%	11.14%	8/10/2016	2.66%
11/6/1980	12.59	12.59%	11.13%	8/11/2016	2.65%
11/5/1980	12.36	12.36%	11.12%	8/12/2016	2.65%
11/3/1980	12.22	12.22%	11.12%	8/15/2016	2.65%
10/31/1980	12.23	12.23%	11.11%	8/16/2016	2.64%
10/30/1980	12.28	12.28%	11.10%	8/17/2016	2.64%
10/29/1980	12.21	12.21%	11.09%	8/18/2016	2.63%
10/28/1980	12.14	12.14%	11.08%	8/19/2016	2.63%
10/27/1980	11.96	11.96%	11.07%	8/22/2016	2.62%
10/24/1980	11.61	11.61%	11.06%	8/23/2016	2.62%
10/23/1980	11.68	11.68%	11.06%	8/24/2016	2.62%
10/22/1980	11.74	11.74%	11.05%	8/25/2016	2.61%
10/21/1980	11.53	11.53%	11.04%	8/26/2016	2.61%
10/20/1980	11.44	11.44%	11.04%	8/29/2016	2.61%
10/17/1980	11.44	11.44%	11.03%	8/30/2016	2.60%

10/16/1980	11.27	11.27%	11.02%	8/31/2016	2.60%
10/15/1980	11.11	11.11%	11.02%	9/1/2016	2.59%
10/14/1980	11.16	11.16%	11.01%	9/2/2016	2.59%
10/10/1980	11.26	11.26%	11.01%	9/5/2016	2.59%
10/9/1980	11.21	11.21%	11.00%	9/6/2016	2.58%
10/8/1980	11.38	11.38%	11.00%	9/7/2016	2.58%
10/7/1980	11.3	11.30%	10.99%	9/8/2016	2.58%
10/6/1980	11.26	11.26%	10.99%	9/9/2016	2.57%
10/3/1980	11.33	11.33%	10.98%	9/12/2016	2.57%
10/2/1980	11.66	11.66%	10.97%	9/13/2016	2.57%
10/1/1980	11.69	11.69%	10.97%	9/14/2016	2.57%
9/30/1980	11.7	11.70%	10.96%	9/15/2016	2.56%
9/29/1980	11.93	11.93%	10.95%	9/16/2016	2.56%
9/26/1980	11.81	11.81%	10.94%	9/19/2016	2.56%
9/25/1980	11.66	11.66%	10.94%	9/20/2016	2.56%
9/24/1980	11.53	11.53%	10.93%	9/21/2016	2.55%
9/23/1980	11.53	11.53%	10.92%	9/22/2016	2.55%
9/22/1980	11.6	11.60%	10.91%	9/23/2016	2.55%
9/19/1980	11.25	11.25%	10.90%	9/26/2016	2.54%
9/18/1980	11.35	11.35%	10.90%	9/27/2016	2.54%
9/17/1980	11.41	11.41%	10.89%	9/28/2016	2.54%
9/16/1980	11.33	11.33%	10.89%	9/29/2016	2.53%
9/15/1980	11.38	11.38%	10.88%	9/30/2016	2.53%
9/12/1980	11.18	11.18%	10.87%	10/3/2016	2.53%
9/11/1980	11.15	11.15%	10.87%	10/4/2016	2.52%
9/10/1980	11.02	11.02%	10.86%	10/5/2016	2.52%
9/9/1980	11.05	11.05%	10.86%	10/6/2016	2.52%
9/8/1980	11.15	11.15%	10.85%	10/7/2016	2.51%
9/5/1980	11.06	11.06%	10.85%	10/10/2016	2.51%
9/4/1980	11.02	11.02%	10.85%	10/11/2016	2.51%
9/3/1980	10.94	10.94%	10.84%	10/12/2016	2.51%
9/2/1980	11.08	11.08%	10.84%	10/13/2016	2.51%
8/29/1980	11.27	11.27%	10.84%	10/14/2016	2.50%
8/28/1980	11.43	11.43%	10.83%	10/17/2016	2.50%
8/27/1980	11.33	11.33%	10.83%	10/18/2016	2.50%
8/26/1980	11.18	11.18%	10.82%	10/19/2016	2.50%
8/25/1980	11.18	11.18%	10.82%	10/20/2016	2.50%
8/22/1980	11.01	11.01%	10.82%	10/21/2016	2.49%
8/21/1980	11.15	11.15%	10.81%	10/24/2016	2.49%
8/20/1980	11.13	11.13%	10.81%	10/25/2016	2.49%
8/19/1980	11.16	11.16%	10.80%	10/26/2016	2.49%
8/18/1980	11.02	11.02%	10.80%	10/27/2016	2.49%
8/15/1980	10.83	10.83%	10.79%	10/28/2016	2.49%
8/14/1980	10.9	10.90%	10.79%	10/31/2016	2.49%
8/13/1980	10.93	10.93%	10.79%	11/1/2016	2.49%
8/12/1980	11.01	11.01%	10.78%	11/2/2016	2.48%
8/11/1980	11.05	11.05%	10.78%	11/3/2016	2.48%

8/8/1980	10.9	10.90%	10.78%	11/4/2016	2.48%
8/7/1980	10.68	10.68%	10.77%	11/7/2016	2.48%
8/6/1980	10.73	10.73%	10.77%	11/8/2016	2.48%
8/5/1980	10.69	10.69%	10.76%	11/9/2016	2.48%
8/4/1980	10.68	10.68%	10.76%	11/10/2016	2.48%
8/1/1980	10.76	10.76%	10.76%	11/11/2016	2.49%
7/31/1980	10.8	10.80%	10.75%	11/14/2016	2.49%
7/30/1980	10.51	10.51%	10.75%	11/15/2016	2.49%
7/29/1980	10.4	10.40%	10.74%	11/16/2016	2.49%
7/28/1980	10.42	10.42%	10.74%	11/17/2016	2.49%
7/25/1980	10.33	10.33%	10.73%	11/18/2016	2.50%
7/24/1980	10.24	10.24%	10.73%	11/21/2016	2.50%
7/23/1980	10.15	10.15%	10.72%	11/22/2016	2.50%
7/22/1980	10.18	10.18%	10.72%	11/23/2016	2.50%
7/21/1980	10.11	10.11%	10.71%	11/24/2016	2.50%
7/18/1980	10.19	10.19%	10.71%	11/25/2016	2.51%
7/17/1980	10.15	10.15%	10.71%	11/28/2016	2.51%
7/16/1980	10.05	10.05%	10.70%	11/29/2016	2.51%
7/15/1980	10.19	10.19%	10.70%	11/30/2016	2.51%
7/14/1980	10.36	10.36%	10.69%	12/1/2016	2.51%
7/11/1980	10.3	10.30%	10.68%	12/2/2016	2.52%
7/10/1980	10.21	10.21%	10.68%	12/5/2016	2.52%
7/9/1980	10.14	10.14%	10.67%	12/6/2016	2.52%
7/8/1980	10.06	10.06%	10.67%	12/7/2016	2.52%
7/7/1980	10.22	10.22%	10.66%	12/8/2016	2.52%
7/3/1980	10	10.00%	10.66%	12/9/2016	2.53%
7/2/1980	10.12	10.12%	10.66%	12/12/2016	2.53%
7/1/1980	10.12	10.12%	10.65%	12/13/2016	2.53%
6/30/1980	9.99	9.99%	10.65%	12/14/2016	2.53%
6/27/1980	9.97	9.97%	10.64%	12/15/2016	2.54%
6/26/1980	9.91	9.91%	10.64%	12/16/2016	2.54%
6/25/1980	9.79	9.79%	10.63%	12/19/2016	2.54%
6/24/1980	9.7	9.70%	10.63%	12/20/2016	2.54%
6/23/1980	9.66	9.66%	10.63%	12/21/2016	2.54%
6/20/1980	9.5	9.50%	10.62%	12/22/2016	2.55%
6/19/1980	9.57	9.57%	10.62%	12/23/2016	2.55%
6/18/1980	9.6	9.60%	10.62%	12/26/2016	2.55%
6/17/1980	9.52	9.52%	10.62%	12/27/2016	2.55%
6/16/1980	9.49	9.49%	10.61%	12/28/2016	2.55%
6/13/1980	9.49	9.49%	10.61%	12/29/2016	2.56%
6/12/1980	9.6	9.60%	10.61%	12/30/2016	2.56%
6/11/1980	9.79	9.79%	10.61%	1/2/2017	2.56%
6/10/1980	9.88	9.88%	10.60%	1/3/2017	2.56%
6/9/1980	9.75	9.75%	10.60%	1/4/2017	2.57%
6/6/1980	9.87	9.87%	10.59%	1/5/2017	2.57%
6/5/1980	10.08	10.08%	10.59%	1/6/2017	2.57%
6/4/1980	10.18	10.18%	10.58%	1/9/2017	2.57%

6/3/1980	10.29	10.29%	10.58%	1/10/2017	2.57%
6/2/1980	10.45	10.45%	10.57%	1/11/2017	2.57%
5/30/1980	10.37	10.37%	10.56%	1/12/2017	2.58%
5/29/1980	10.32	10.32%	10.56%	1/13/2017	2.58%
5/28/1980	10.22	10.22%	10.55%	1/16/2017	2.58%
5/27/1980	10.1	10.10%	10.54%	1/17/2017	2.58%
5/23/1980	10.09	10.09%	10.54%	1/18/2017	2.58%
5/22/1980	10.34	10.34%	10.53%	1/19/2017	2.59%
5/21/1980	10.31	10.31%	10.52%	1/20/2017	2.59%
5/20/1980	10.47	10.47%	10.52%	1/23/2017	2.59%
5/19/1980	10.68	10.68%	10.51%	1/24/2017	2.59%
5/16/1980	10.53	10.53%	10.50%	1/25/2017	2.60%
5/15/1980	10.46	10.46%	10.49%	1/26/2017	2.60%
5/14/1980	10.26	10.26%	10.49%	1/27/2017	2.60%
5/13/1980	10.29	10.29%	10.48%	1/30/2017	2.60%
5/12/1980	10.44	10.44%	10.47%	1/31/2017	2.60%
5/9/1980	10.41	10.41%	10.47%	2/1/2017	2.61%
5/8/1980	10.34	10.34%	10.46%	2/2/2017	2.61%
5/7/1980	10.19	10.19%	10.45%	2/3/2017	2.61%
5/6/1980	10.23	10.23%	10.45%	2/6/2017	2.61%
5/5/1980	10.35	10.35%	10.44%	2/7/2017	2.61%
5/2/1980	10.47	10.47%	10.43%	2/8/2017	2.61%
5/1/1980	10.72	10.72%	10.43%	2/9/2017	2.62%
4/30/1980	10.89	10.89%	10.42%	2/10/2017	2.62%
4/29/1980	10.89	10.89%	10.41%	2/13/2017	2.62%
4/28/1980	10.86	10.86%	10.40%	2/14/2017	2.62%
4/25/1980	11.18	11.18%	10.39%	2/15/2017	2.62%
4/24/1980	11.13	11.13%	10.38%	2/16/2017	2.63%
4/23/1980	11.02	11.02%	10.36%	2/17/2017	2.63%
4/22/1980	10.94	10.94%	10.35%	2/20/2017	2.63%
4/21/1980	10.96	10.96%	10.34%	2/21/2017	2.63%
4/18/1980	10.98	10.98%	10.33%	2/22/2017	2.64%
4/17/1980	10.99	10.99%	10.32%	2/23/2017	2.64%
4/16/1980	10.91	10.91%	10.31%	2/24/2017	2.64%
4/15/1980	11.47	11.47%	10.30%	2/27/2017	2.64%
4/14/1980	11.5	11.50%	10.29%	2/28/2017	2.64%
4/11/1980	11.53	11.53%	10.27%	3/1/2017	2.64%
4/10/1980	11.74	11.74%	10.26%	3/2/2017	2.65%
4/9/1980	11.79	11.79%	10.25%	3/3/2017	2.65%
4/8/1980	11.85	11.85%	10.23%	3/6/2017	2.65%
4/7/1980	11.87	11.87%	10.22%	3/7/2017	2.65%
4/3/1980	12.27	12.27%	10.20%	3/8/2017	2.66%
4/2/1980	12.28	12.28%	10.19%	3/9/2017	2.66%
4/1/1980	12.35	12.35%	10.17%	3/10/2017	2.66%
3/31/1980	12.31	12.31%	10.15%	3/13/2017	2.67%
3/28/1980	12.35	12.35%	10.13%	3/14/2017	2.67%
3/27/1980	12.5	12.50%	10.12%	3/15/2017	2.67%

3/26/1980	12.56	12.56%	10.10%	3/16/2017	2.68%
3/25/1980	12.67	12.67%	10.08%	3/17/2017	2.68%
3/24/1980	12.69	12.69%	10.06%	3/20/2017	2.68%
3/21/1980	12.28	12.28%	10.05%	3/21/2017	2.68%
3/20/1980	12.22	12.22%	10.03%	3/22/2017	2.69%
3/19/1980	11.97	11.97%	10.01%	3/23/2017	2.69%
3/18/1980	12	12.00%	10.00%	3/24/2017	2.69%
3/17/1980	12.2	12.20%	9.98%	3/27/2017	2.70%
3/14/1980	12.21	12.21%	9.97%	3/28/2017	2.70%
3/13/1980	12.19	12.19%	9.95%	3/29/2017	2.70%
3/12/1980	12.39	12.39%	9.94%	3/30/2017	2.70%
3/11/1980	12.12	12.12%	9.92%	3/31/2017	2.71%
3/10/1980	12.25	12.25%	9.91%	4/3/2017	2.71%
3/7/1980	12.5	12.50%	9.89%	4/4/2017	2.71%
3/6/1980	12.64	12.64%	9.88%	4/5/2017	2.72%
3/5/1980	12.4	12.40%	9.86%	4/6/2017	2.72%
3/4/1980	12.35	12.35%	9.84%	4/7/2017	2.72%
3/3/1980	12.32	12.32%	9.83%	4/10/2017	2.73%
2/29/1980	12.25	12.25%	9.81%	4/11/2017	2.73%
2/28/1980	12.29	12.29%	9.80%	4/12/2017	2.74%
2/27/1980	12.76	12.76%	9.78%	4/13/2017	2.74%
2/26/1980	12.85	12.85%	9.76%	4/14/2017	2.74%
2/25/1980	12.69	12.69%	9.75%	4/17/2017	2.75%
2/22/1980	12.59	12.59%	9.73%	4/18/2017	2.75%
2/21/1980	12.77	12.77%	9.71%	4/19/2017	2.75%
2/20/1980	12.56	12.56%	9.69%	4/20/2017	2.76%
2/19/1980	12.61	12.61%	9.68%	4/21/2017	2.76%
2/15/1980	12.11	12.11%	9.66%	4/24/2017	2.76%
2/14/1980	11.9	11.90%	9.65%	4/25/2017	2.77%
2/13/1980	11.82	11.82%	9.63%	4/26/2017	2.77%
2/11/1980	11.94	11.94%	9.62%	4/27/2017	2.77%
2/8/1980	11.72	11.72%	9.61%	4/28/2017	2.78%
2/7/1980	11.7	11.70%	9.59%	5/1/2017	2.78%
2/6/1980	11.78	11.78%	9.58%	5/2/2017	2.78%
2/5/1980	11.64	11.64%	9.57%	5/3/2017	2.79%
2/4/1980	11.32	11.32%	9.55%	5/4/2017	2.79%
2/1/1980	11.23	11.23%	9.54%	5/5/2017	2.80%
1/31/1980	11.09	11.09%	9.53%	5/8/2017	2.80%
1/30/1980	11.11	11.11%	9.52%	5/9/2017	2.80%
1/29/1980	11.12	11.12%	9.51%	5/10/2017	2.81%
1/28/1980	11.03	11.03%	9.50%	5/11/2017	2.81%
1/25/1980	11	11.00%	9.49%	5/12/2017	2.81%
1/24/1980	10.87	10.87%	9.48%	5/15/2017	2.82%
1/23/1980	10.68	10.68%	9.47%	5/16/2017	2.82%
1/22/1980	10.69	10.69%	9.46%	5/17/2017	2.83%
1/21/1980	10.77	10.77%	9.45%	5/18/2017	2.83%
1/18/1980	10.61	10.61%	9.45%	5/19/2017	2.83%

1/17/1980	10.47	10.47%	9.44%	5/22/2017	2.83%
1/16/1980	10.41	10.41%	9.43%	5/23/2017	2.84%
1/15/1980	10.4	10.40%	9.42%	5/24/2017	2.84%
1/14/1980	10.4	10.40%	9.42%	5/25/2017	2.84%
1/11/1980	10.38	10.38%	9.41%	5/26/2017	2.85%
1/10/1980	10.26	10.26%	9.40%	5/29/2017	2.85%
1/9/1980	10.29	10.29%	9.40%	5/30/2017	2.85%
1/8/1980	10.28	10.28%	9.39%	5/31/2017	2.86%
1/7/1980	10.35	10.35%	9.38%	6/1/2017	2.86%
1/4/1980	10.34	10.34%	9.38%	6/2/2017	2.86%
1/3/1980	10.31	10.31%	9.37%	6/5/2017	2.87%
1/2/1980	10.23	10.23%	9.36%	6/6/2017	2.87%
12/31/1979	10.11	10.11%	9.36%	6/7/2017	2.87%
12/28/1979	10.16	10.16%	9.35%	6/8/2017	2.88%
12/27/1979	10.19	10.19%	9.35%	6/9/2017	2.88%
12/26/1979	10.2	10.20%	9.34%	6/12/2017	2.88%
12/24/1979	10.17	10.17%	9.34%	6/13/2017	2.88%
12/21/1979	10.17	10.17%	9.33%	6/14/2017	2.89%
12/20/1979	10.13	10.13%	9.32%	6/15/2017	2.89%
12/19/1979	10.09	10.09%	9.32%	6/16/2017	2.89%
12/18/1979	10.11	10.11%	9.31%	6/19/2017	2.89%
12/17/1979	10.14	10.14%	9.31%	6/20/2017	2.89%
12/14/1979	10.17	10.17%	9.30%	6/21/2017	2.90%
12/13/1979	10.23	10.23%	9.30%	6/22/2017	2.90%
12/12/1979	10.27	10.27%	9.29%	6/23/2017	2.90%
12/11/1979	10.18	10.18%	9.29%	6/26/2017	2.90%
12/10/1979	10.03	10.03%	9.28%	6/27/2017	2.90%
12/7/1979	10.04	10.04%	9.28%	6/28/2017	2.90%
12/6/1979	9.93	9.93%	9.27%	6/29/2017	2.91%
12/5/1979	10.01	10.01%	9.27%	6/30/2017	2.91%
12/4/1979	10.04	10.04%	9.26%	7/3/2017	2.91%
12/3/1979	10.11	10.11%	9.26%	7/4/2017	2.91%
11/30/1979	10.09	10.09%	9.25%	7/5/2017	2.92%
11/29/1979	10.06	10.06%	9.24%	7/6/2017	2.92%
11/28/1979	10.09	10.09%	9.24%	7/7/2017	2.92%
11/27/1979	10.02	10.02%	9.23%	7/10/2017	2.93%
11/26/1979	10.1	10.10%	9.23%	7/11/2017	2.93%
11/23/1979	10.21	10.21%	9.22%	7/12/2017	2.93%
11/21/1979	10.36	10.36%	9.21%	7/13/2017	2.93%
11/20/1979	10.39	10.39%	9.21%	7/14/2017	2.94%
11/19/1979	10.42	10.42%	9.20%	7/17/2017	2.94%
11/16/1979	10.41	10.41%	9.19%	7/18/2017	2.94%
11/15/1979	10.3	10.30%	9.18%	7/19/2017	2.94%
11/14/1979	10.4	10.40%	9.18%	7/20/2017	2.94%
11/13/1979	10.32	10.32%	9.17%	7/21/2017	2.94%
11/9/1979	10.34	10.34%	9.16%	7/24/2017	2.95%
11/8/1979	10.51	10.51%	9.15%	7/25/2017	2.95%

11/7/1979	10.53	10.53%	9.15%	7/26/2017	2.95%
11/5/1979	10.42	10.42%	9.14%	7/27/2017	2.95%
11/2/1979	10.44	10.44%	9.13%	7/28/2017	2.95%
11/1/1979	10.3	10.30%	9.12%	7/31/2017	2.96%
10/31/1979	10.19	10.19%	9.12%	8/1/2017	2.96%
10/30/1979	10.17	10.17%	9.11%	8/2/2017	2.96%
10/29/1979	10.22	10.22%	9.11%	8/3/2017	2.96%
10/26/1979	10.12	10.12%	9.10%	8/4/2017	2.96%
10/25/1979	10.31	10.31%	9.09%	8/7/2017	2.96%
10/24/1979	10.2	10.20%	9.09%	8/8/2017	2.96%
10/23/1979	10.33	10.33%	9.08%	8/9/2017	2.96%
10/22/1979	10.29	10.29%	9.07%	8/10/2017	2.97%
10/19/1979	10.07	10.07%	9.07%	8/11/2017	2.97%
10/18/1979	9.91	9.91%	9.06%	8/14/2017	2.97%
10/17/1979	9.75	9.75%	9.06%	8/15/2017	2.97%
10/16/1979	9.82	9.82%	9.05%	8/16/2017	2.97%
10/15/1979	9.84	9.84%	9.05%	8/17/2017	2.97%
10/12/1979	9.76	9.76%	9.05%	8/18/2017	2.97%
10/11/1979	9.77	9.77%	9.04%	8/21/2017	2.97%
10/10/1979	9.69	9.69%	9.04%	8/22/2017	2.97%
10/9/1979	9.61	9.61%	9.04%	8/23/2017	2.96%
10/5/1979	9.36	9.36%	9.03%	8/24/2017	2.96%
10/4/1979	9.34	9.34%	9.03%	8/25/2017	2.96%
10/3/1979	9.3	9.30%	9.03%	8/28/2017	2.96%
10/2/1979	9.28	9.28%	9.03%	8/29/2017	2.96%
10/1/1979	9.32	9.32%	9.03%	8/30/2017	2.96%
9/28/1979	9.25	9.25%	9.03%	8/31/2017	2.96%
9/27/1979	9.25	9.25%	9.02%	9/1/2017	2.96%
9/26/1979	9.2	9.20%	9.02%	9/4/2017	2.95%
9/25/1979	9.16	9.16%	9.02%	9/5/2017	2.95%
9/24/1979	9.17	9.17%	9.02%	9/6/2017	2.95%
9/21/1979	9.11	9.11%	9.02%	9/7/2017	2.95%
9/20/1979	9.13	9.13%	9.02%	9/8/2017	2.95%
9/19/1979	9.16	9.16%	9.02%	9/11/2017	2.95%
9/18/1979	9.19	9.19%	9.02%	9/12/2017	2.94%
9/17/1979	9.19	9.19%	9.02%	9/13/2017	2.94%
9/14/1979	9.13	9.13%	9.02%	9/14/2017	2.94%
9/13/1979	9.17	9.17%	9.02%	9/15/2017	2.94%
9/12/1979	9.15	9.15%	9.02%	9/18/2017	2.94%
9/11/1979	9.13	9.13%	9.01%	9/19/2017	2.94%
9/10/1979	9.19	9.19%	9.01%	9/20/2017	2.93%
9/7/1979	9.18	9.18%	9.01%	9/21/2017	2.93%
9/6/1979	9.16	9.16%	9.01%	9/22/2017	2.93%
9/5/1979	9.15	9.15%	9.01%	9/25/2017	2.93%
9/4/1979	9.14	9.14%	9.01%	9/26/2017	2.93%
8/31/1979	9.09	9.09%	9.01%	9/27/2017	2.93%
8/30/1979	9.07	9.07%	9.01%	9/28/2017	2.92%

8/29/1979	9.02	9.02%	9.01%	9/29/2017	2.92%
8/28/1979	9.03	9.03%	9.01%	10/2/2017	2.92%
8/27/1979	9.03	9.03%	9.01%	10/3/2017	2.92%
8/24/1979	9.05	9.05%	9.01%	10/4/2017	2.92%
8/23/1979	9	9.00%	9.01%	10/5/2017	2.92%
8/22/1979	8.99	8.99%	9.01%	10/6/2017	2.92%
8/21/1979	8.99	8.99%	9.01%	10/9/2017	2.92%
8/20/1979	8.96	8.96%	9.01%	10/10/2017	2.92%
8/17/1979	8.95	8.95%	9.01%	10/11/2017	2.91%
8/16/1979	8.95	8.95%	9.01%	10/12/2017	2.91%
8/15/1979	8.96	8.96%	9.01%	10/13/2017	2.91%
8/14/1979	8.95	8.95%	9.01%	10/16/2017	2.91%
8/13/1979	8.97	8.97%	9.01%	10/17/2017	2.91%
8/10/1979	8.97	8.97%	9.01%	10/18/2017	2.91%
8/9/1979	8.95	8.95%	9.01%	10/19/2017	2.91%
8/8/1979	8.91	8.91%	9.01%	10/20/2017	2.91%
8/7/1979	8.9	8.90%	9.01%	10/23/2017	2.91%
8/6/1979	8.92	8.92%	9.01%	10/24/2017	2.91%
8/3/1979	8.94	8.94%	9.01%	10/25/2017	2.91%
8/2/1979	8.92	8.92%	9.01%	10/26/2017	2.91%
8/1/1979	8.97	8.97%	9.01%	10/27/2017	2.91%
7/31/1979	8.99	8.99%	9.01%	10/30/2017	2.91%
7/30/1979	9.01	9.01%	9.01%	10/31/2017	2.91%
7/27/1979	9.01	9.01%	9.01%	11/1/2017	2.91%
7/26/1979	8.98	8.98%	9.01%	11/2/2017	2.90%
7/25/1979	8.97	8.97%	9.01%	11/3/2017	2.90%
7/24/1979	9.01	9.01%	9.01%	11/6/2017	2.90%
7/23/1979	8.99	8.99%	9.01%	11/7/2017	2.90%
7/20/1979	8.95	8.95%	9.02%	11/8/2017	2.90%
7/19/1979	8.99	8.99%	9.02%	11/9/2017	2.90%
7/18/1979	8.99	8.99%	9.02%	11/10/2017	2.90%
7/17/1979	8.97	8.97%	9.02%	11/13/2017	2.90%
7/16/1979	8.95	8.95%	9.02%	11/14/2017	2.89%
7/13/1979	8.91	8.91%	9.02%	11/15/2017	2.89%
7/12/1979	8.91	8.91%	9.02%	11/16/2017	2.89%
7/11/1979	8.93	8.93%	9.02%	11/17/2017	2.89%
7/10/1979	8.89	8.89%	9.02%	11/20/2017	2.89%
7/9/1979	8.86	8.86%	9.02%	11/21/2017	2.89%
7/6/1979	8.83	8.83%	9.02%	11/22/2017	2.89%
7/5/1979	8.82	8.82%	9.02%	11/23/2017	2.89%
7/3/1979	8.81	8.81%	9.02%	11/24/2017	2.88%
7/2/1979	8.8	8.80%	9.03%	11/27/2017	2.88%
6/29/1979	8.83	8.83%	9.03%	11/28/2017	2.88%
6/28/1979	8.84	8.84%	9.03%	11/29/2017	2.88%
6/27/1979	8.83	8.83%	9.03%	11/30/2017	2.88%
6/26/1979	8.84	8.84%	9.03%	12/1/2017	2.88%
6/25/1979	8.92	8.92%	9.03%	12/4/2017	2.88%

6/22/1979	8.95	8.95%	9.04%	12/5/2017	2.88%
6/21/1979	8.92	8.92%	9.04%	12/6/2017	2.87%
6/20/1979	8.92	8.92%	9.04%	12/7/2017	2.87%
6/19/1979	8.94	8.94%	9.04%	12/8/2017	2.87%
6/18/1979	8.93	8.93%	9.04%	12/11/2017	2.87%
6/15/1979	8.94	8.94%	9.04%	12/12/2017	2.87%
6/14/1979	8.89	8.89%	9.04%	12/13/2017	2.87%
6/13/1979	8.87	8.87%	9.04%	12/14/2017	2.86%
6/12/1979	8.84	8.84%	9.04%	12/15/2017	2.86%
6/11/1979	8.94	8.94%	9.05%	12/18/2017	2.86%
6/8/1979	8.91	8.91%	9.05%	12/19/2017	2.86%
6/7/1979	8.9	8.90%	9.05%	12/20/2017	2.86%
6/6/1979	9	9.00%	9.05%	12/21/2017	2.85%
6/5/1979	9.04	9.04%	9.05%	12/22/2017	2.85%
6/4/1979	9.07	9.07%	9.05%	12/25/2017	2.85%
6/1/1979	9.07	9.07%	9.05%	12/26/2017	2.85%
5/31/1979	9.08	9.08%	9.05%	12/27/2017	2.85%
5/29/1979	9.03	9.03%	9.05%	12/28/2017	2.85%
5/25/1979	9.03	9.03%	9.05%	12/29/2017	2.85%
5/24/1979	9.07	9.07%	9.05%	1/1/2018	2.85%
5/23/1979	9.09	9.09%	9.05%	1/2/2018	2.84%
5/22/1979	9.16	9.16%	9.05%	1/3/2018	2.84%
5/21/1979	9.2	9.20%	9.05%	1/4/2018	2.84%
5/18/1979	9.18	9.18%	9.05%	1/5/2018	2.84%
5/17/1979	9.2	9.20%	9.04%	1/8/2018	2.84%
5/16/1979	9.22	9.22%	9.04%	1/9/2018	2.84%
5/15/1979	9.24	9.24%	9.04%	1/10/2018	2.84%
5/14/1979	9.22	9.22%	9.04%	1/11/2018	2.84%
5/11/1979	9.26	9.26%	9.04%	1/12/2018	2.84%
5/10/1979	9.27	9.27%	9.03%	1/15/2018	2.84%
5/9/1979	9.26	9.26%	9.03%	1/16/2018	2.84%
5/8/1979	9.28	9.28%	9.03%	1/17/2018	2.84%
5/7/1979	9.28	9.28%	9.03%	1/18/2018	2.84%
5/4/1979	9.29	9.29%	9.02%	1/19/2018	2.84%
5/3/1979	9.27	9.27%	9.02%	1/22/2018	2.84%
5/2/1979	9.22	9.22%	9.02%	1/23/2018	2.84%
5/1/1979	9.21	9.21%	9.01%	1/24/2018	2.84%
4/30/1979	9.22	9.22%	9.01%	1/25/2018	2.84%
4/27/1979	9.19	9.19%	9.01%	1/26/2018	2.84%
4/26/1979	9.18	9.18%	9.01%	1/29/2018	2.84%
4/25/1979	9.13	9.13%	9.01%	1/30/2018	2.84%
4/24/1979	9.14	9.14%	9.00%	1/31/2018	2.84%
4/23/1979	9.13	9.13%	9.00%	2/1/2018	2.84%
4/20/1979	9.11	9.11%	9.00%	2/2/2018	2.84%
4/19/1979	9.06	9.06%	9.00%	2/5/2018	2.84%
4/18/1979	9.06	9.06%	9.00%	2/6/2018	2.84%
4/17/1979	9.07	9.07%	9.00%	2/7/2018	2.84%

4/16/1979	9.09	9.09%	9.00%	2/8/2018	2.84%
4/12/1979	9.09	9.09%	8.99%	2/9/2018	2.84%
4/11/1979	9.08	9.08%	8.99%	2/12/2018	2.84%
4/10/1979	9.07	9.07%	8.99%	2/13/2018	2.84%
4/9/1979	9.04	9.04%	8.99%	2/14/2018	2.84%
4/6/1979	9.01	9.01%	8.99%	2/15/2018	2.84%
4/5/1979	8.99	8.99%	8.99%	2/16/2018	2.84%
4/4/1979	9	9.00%	8.99%	2/19/2018	2.85%
4/3/1979	9.01	9.01%	8.99%	2/20/2018	2.85%
4/2/1979	9.02	9.02%	8.99%	2/21/2018	2.85%
3/30/1979	9.02	9.02%	8.99%	2/22/2018	2.85%
3/29/1979	8.99	8.99%	8.99%	2/23/2018	2.85%
3/28/1979	8.99	8.99%	8.99%	2/26/2018	2.85%
3/27/1979	9.01	9.01%	8.99%	2/27/2018	2.85%
3/26/1979	9.03	9.03%	8.99%	2/28/2018	2.85%
3/23/1979	9.02	9.02%	8.99%	3/1/2018	2.85%
3/22/1979	9.03	9.03%	8.99%	3/2/2018	2.86%
3/21/1979	9.03	9.03%	8.99%	3/5/2018	2.86%
3/20/1979	9.04	9.04%	8.99%	3/6/2018	2.86%
3/19/1979	9.03	9.03%	8.98%	3/7/2018	2.86%
3/16/1979	9.03	9.03%	8.98%	3/8/2018	2.86%
3/15/1979	9.05	9.05%	8.98%	3/9/2018	2.86%
3/14/1979	9.04	9.04%	8.98%	3/12/2018	2.86%
3/13/1979	9.02	9.02%	8.98%	3/13/2018	2.87%
3/12/1979	9.02	9.02%	8.98%	3/14/2018	2.87%
3/9/1979	9.04	9.04%	8.98%	3/15/2018	2.87%
3/8/1979	9.01	9.01%	8.98%	3/16/2018	2.87%
3/7/1979	9.02	9.02%	8.98%	3/19/2018	2.87%
3/6/1979	9.06	9.06%	8.98%	3/20/2018	2.87%
3/5/1979	9.02	9.02%	8.97%	3/21/2018	2.87%
3/2/1979	9.09	9.09%	8.97%	3/22/2018	2.87%
3/1/1979	9.09	9.09%	8.97%	3/23/2018	2.88%
2/28/1979	9.08	9.08%	8.97%	3/26/2018	2.88%
2/27/1979	9.08	9.08%	8.96%	3/27/2018	2.88%
2/26/1979	9.08	9.08%	8.96%	3/28/2018	2.88%
2/23/1979	9.1	9.10%	8.96%	3/29/2018	2.88%
2/22/1979	9.08	9.08%	8.95%	3/30/2018	2.88%
2/21/1979	9.04	9.04%	8.95%	4/2/2018	2.88%
2/20/1979	9.02	9.02%	8.95%	4/3/2018	2.89%
2/16/1979	9.01	9.01%	8.94%	4/4/2018	2.89%
2/15/1979	9.01	9.01%	8.94%	4/5/2018	2.89%
2/14/1979	9	9.00%	8.94%	4/6/2018	2.89%
2/13/1979	9	9.00%	8.94%	4/9/2018	2.89%
2/9/1979	9.02	9.02%	8.94%	4/10/2018	2.89%
2/8/1979	9	9.00%	8.93%	4/11/2018	2.89%
2/7/1979	9	9.00%	8.93%	4/12/2018	2.89%
2/6/1979	8.92	8.92%	8.93%	4/13/2018	2.89%

2/5/1979	8.88	8.88%	8.93%	4/16/2018	2.89%
2/2/1979	8.84	8.84%	8.93%	4/17/2018	2.89%
2/1/1979	8.85	8.85%	8.93%	4/18/2018	2.89%
1/31/1979	8.85	8.85%	8.94%	4/19/2018	2.89%
1/30/1979	8.85	8.85%	8.94%	4/20/2018	2.90%
1/29/1979	8.85	8.85%	8.95%	4/23/2018	2.90%
1/26/1979	8.82	8.82%	8.95%	4/24/2018	2.90%
1/25/1979	8.84	8.84%	8.96%	4/25/2018	2.90%
1/24/1979	8.91	8.91%	8.97%	4/26/2018	2.90%
1/23/1979	8.93	8.93%	8.97%	4/27/2018	2.90%
1/22/1979	8.94	8.94%	8.97%	4/30/2018	2.91%
1/19/1979	8.97	8.97%	8.98%	5/1/2018	2.91%
1/18/1979	8.99	8.99%	8.98%	5/2/2018	2.91%
1/17/1979	8.99	8.99%	8.97%	5/3/2018	2.91%
1/16/1979	8.98	8.98%	8.97%	5/4/2018	2.91%
1/15/1979	8.97	8.97%	8.97%	5/7/2018	2.91%
1/12/1979	8.97	8.97%	8.97%	5/8/2018	2.91%
1/11/1979	8.98	8.98%	8.97%	5/9/2018	2.91%
1/10/1979	8.99	8.99%	8.97%	5/10/2018	2.92%
1/9/1979	8.99	8.99%	8.97%	5/11/2018	2.92%
1/8/1979	8.98	8.98%	8.96%	5/14/2018	2.92%
1/5/1979	8.95	8.95%	8.96%	5/15/2018	2.92%
1/4/1979	8.94	8.94%	8.96%	5/16/2018	2.92%
1/3/1979	8.96	8.96%	8.98%	5/17/2018	2.92%
1/2/1979	8.99	8.99%	8.99%	5/18/2018	2.93%

SNLTable

Company Name	SNL Institution Key		Total Proprietary Capital ($000)	Total Proprietary Capital ($000)	Total Proprietary Capital ($000)	Total Proprietary Capital ($000)	Total Proprietary Capital ($000)	Total Proprietary Capital ($000)	Total Proprietary Capital ($000)	Total Proprietary Capital ($000)
	201129	201136	201284	201284	201284	201284	201284	201284	201284	201284
			2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2
ALLETE (Minnesota Power)		4061513	2,098,543	2,069,267	2,043,517	2,017,816	2,002,273	1,893,811	1,872,732	1,851,932
Black Hills Colorado Electric Utility Company, LP		4215172	422,339	439,923	427,149	427,867	395,916	382,172	376,861	370,000
Black Hills Power, Inc.		4065694	390,021	394,232	877,373	390,568	390,257	384,662	388,553	388,519
Cheyenne Light, Fuel and Power Company		4059189	232,069	237,200	229,257	230,243	230,463	231,010	229,764	229,066
El Paso Electric Company		4056994	1,138,269	1,160,566	1,154,057	1,104,543	1,081,492	1,092,355	1,092,259	1,028,289
Hawaiian Electric Company, Inc.		4057001	NA	NA	NA	NA	NA	NA	NA	NA
Idaho Power Co.		4057002	2,092,266	2,085,775	2,085,829	2,024,813	2,003,745	1,998,703	1,998,882	1,944,027
Interstate Power and Light Company		4057087	2,718,621	2,715,633	2,638,289	2,550,970	2,447,128	2,448,977	2,337,923	2,236,829
NorthWestern Corporation		4057053	1,834,622	1,798,915	1,726,190	1,708,597	1,709,204	1,676,226	1,648,807	1,627,634
Oklahoma Gas and Electric Company		4057016	3,487,998	3,455,703	3,412,887	3,356,261	3,269,103	3,252,113	3,270,671	3,175,571
Public Service Company of New Mexico		4073320	1,441,688	1,433,702	1,523,246	1,459,562	1,429,964	1,409,401	1,412,606	1,347,084
Superior Water, Light and Power Company		4063281	52,898	51,047	45,497	45,021	44,581	43,239	44,201	43,966
Texas-New Mexico Power Company		4057028	NA	NA	NA	NA	NA	NA	NA	NA
Wisconsin Power and Light Company		4008669	1,921,455	1,901,831	1,828,625	1,770,143	1,763,399	1,749,315	1,832,864	1,797,885

SNLTable

Institution Name	SNL Institution Key		Common Equity (Reported)	Common Equity (Reported)	Common Equity (Reported)	Common Equity (Reported)	Common Equity (Reported)	Common Equity (Reported)	Common Equity (Reported)	Common Equity (Reported)
	130509	130992	132384	132384	132384	132384	132384	132384	132384	132384
			2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2
			Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated
Hawaiian Electric Company, Inc.		4057001	1,846,955	1,845,283	1,829,075	1,803,506	1,799,769	1,799,787	1,766,727	1,743,006
			56.18%	58.23%	58.00%	56.96%	57.68%	57.70%	57.60%	56.98%
		check	*100.00%*	*100.00%*	*100.00%*	*100.00%*	*100.00%*	*100.00%*	*100.00%*	*100.00%*

Preferred Stock Issued ($000)	Preferred Stock Issued ($000)	Preferred Stock Issued ($000)	Preferred Stock Issued ($000)	Preferred Stock Issued ($000)	Preferred Stock Issued ($000)	Preferred Stock Issued ($000)	Preferred Stock Issued ($000)	Total Long-term Debt ($000)	Total Long-term Debt ($000)	Total Long-term Debt ($000)	Total Long-term Debt ($000)
201247	201247	201247	201247	201247	201247	201247	201247	201292	201292	201292	201292
2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	2018Q1	2017Q4	2017Q3	2017Q2
0	0	0	0	0	0	0	0	1,377,107	1,377,343	1,377,655	1,392,809
0	0	0	0	0	0	0	0	350,000	350,000	350,000	350,000
0	0	0	0	0	0	0	0	342,766	342,765	685,527	342,763
0	0	0	0	0	0	0	0	202,000	202,000	202,000	202,000
0	0	0	0	0	0	0	0	1,163,024	1,163,025	1,163,026	1,196,327
NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
0	0	0	0	0	0	0	0	1,980,480	1,761,220	1,761,147	1,761,074
200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	2,526,888	2,484,863	2,269,482	2,268,311
0	0	0	0	0	0	0	0	2,029,637	1,806,637	1,806,612	1,806,608
0	0	0	0	0	0	0	0	3,020,258	3,020,149	3,020,032	3,005,905
11,529	11,529	11,529	11,529	11,529	11,529	11,529	11,529	1,665,273	1,665,246	1,665,219	1,640,192
0	0	0	0	0	0	0	0	27,500	27,500	27,500	27,500
NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
0	0	0	0	0	0	0	0	1,954,655	1,961,532	1,662,114	1,663,081

Short-term Debt (Reported)	Short-term Debt (Reported)	Short-term Debt (Reported)	Short-term Debt (Reported)	Short-term Debt (Reported)	Short-term Debt (Reported)	Short-term Debt (Reported)	Short-term Debt (Reported)	Non-current Long-term Debt (R	Non-current Long-term Debt (R	Non-current Long-term Debt (R	Non-current Long-term Debt (R
132351	132351	132351	132351	132351	132351	132351	132351	132356	132356	132356	132356
2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	2018Q1	2017Q4	2017Q3	2017Q2
Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated
121,983	4,999	6,000	43,990	1,500	0	21,000	36,995	1,318,654	1,318,516	1,318,623	1,318,845
3.71%	0.16%	0.19%	1.39%	0.05%	0.00%	0.68%	1.21%	40.11%	41.61%	41.81%	41.65%

Total Long-term Debt ($000)	Total Long-term Debt ($000)	Total Long-term Debt ($000)	Total Long-term Debt ($000)	Notes Payable ($000)	Notes Payable ($000)	Notes Payable ($000)	Notes Payable ($000)	Notes Payable ($000)	Notes Payable ($000)	Notes Payable ($000)	Notes Payable ($000)	CE	CE	CE
201292	201292	201292	201292	201304	201304	201304	201304	201304	201304	201304	201304			
2017Q1	2016Q4	2016Q3	2016Q2	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	2018Q1	2017Q4	2017Q3
1,408,039	1,433,268	1,418,296	1,418,296	0	0	0	0	0	0	0	0	2,098,543	2,069,267	2,043,517
350,000	350,000	350,000	350,000	0	0	0	0	0	0	0	0	422,339	439,923	427,149
342,762	342,760	342,759	342,758	0	0	0	0	0	0	0	0	390,021	394,232	877,373
202,000	202,000	202,000	202,000	0	0	0	0	0	0	0	0	232,069	237,200	229,257
1,196,328	1,196,330	1,196,331	1,196,333	144,000	85,000	77,000	140,000	94,000	44,000	19,000	67,000	1,138,269	1,160,566	1,154,057
NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	#VALUE!	#VALUE!	#VALUE!
1,761,001	1,761,991	1,761,918	1,761,845	0	0	0	0	0	21,800	0	0	2,092,266	2,085,775	2,085,829
2,226,741	2,227,855	2,226,066	1,993,098	0	0	4,000	0	9,200	0	0	0	2,518,621	2,515,633	2,438,289
1,806,603	1,806,599	1,806,595	1,787,136	0	319,556	269,738	303,658	228,901	300,811	222,311	256,806	1,834,622	1,798,915	1,726,190
2,845,826	2,545,952	2,545,874	2,545,796	0	0	0	0	0	0	0	0	3,487,998	3,455,703	3,412,887
1,640,165	1,640,138	1,640,110	1,640,083	0	39,800	0	38,000	16,200	61,000	42,400	126,000	1,430,159	1,422,173	1,511,717
27,500	27,500	27,500	27,500	0	0	0	0	0	0	0	0	52,898	51,047	45,497
NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	#VALUE!	#VALUE!	#VALUE!
1,663,738	1,666,212	1,666,527	1,666,622	30600	25000	224600	212500	91200	52300	11800	45800	1,921,455	1,901,831	1,828,625

Non-current Long-term Debt (R	Non-current Long-term Debt (R	Non-current Long-term Debt (R	Non-current Long-term Debt (R	Current Portion of Long-term	Current Portion of Long-term	Current Portion of Long-term	Current Portion of Long-term	Current Portion of Long-terr	Current Portion of Long-terr	Current Portion of Long-terr	Current Portion of Long-term Debt (Reported)
132356	132356	132356	132356	132352	132352	132352	132352	132352	132352	132352	132352
2017Q1	2016Q4	2016Q3	2016Q2	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2
Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated	Current/Restated
1,318,871	1,319,260	1,279,327	1,279,123	49,973	49,963	0	0	0	0	0	0
42.27%	42.30%	41.71%	41.81%								

CE	CE	CE	CE	CE	CAPITAL	CAPITAL	CAPITAL
2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	2018Q1	2017Q4	2017Q3
2,017,816	2,002,273	1,893,811	1,872,732	1,851,932	3,475,650	3,446,610	3,421,172
427,867	395,916	382,172	376,861	370,000	772,339	789,923	777,149
390,568	390,257	384,662	388,553	388,519	732,787	736,997	1,562,900
230,243	230,463	231,010	229,764	229,066	434,069	439,200	431,257
1,104,543	1,081,492	1,092,355	1,092,259	1,028,289	2,445,293	2,408,591	2,394,083
#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!
2,024,813	2,003,745	1,998,703	1,998,882	1,944,027	4,072,746	3,846,995	3,846,976
2,350,970	2,247,128	2,248,977	2,137,923	2,036,829	5,045,509	5,000,496	4,711,771
1,708,597	1,709,204	1,676,226	1,648,807	1,627,634	3,864,259	3,925,108	3,802,540
3,356,261	3,269,103	3,252,113	3,270,671	3,175,571	6,508,256	6,475,852	6,432,919
1,448,033	1,418,435	1,397,872	1,401,077	1,335,555	3,095,432	3,127,219	3,176,936
45,021	44,581	43,239	44,201	43,966	80,398	78,547	72,997
#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!
1,770,143	1,763,399	1,749,315	1,832,864	1,797,885	3,906,710	3,888,363	3,715,339

CAPITAL	CAPITAL	CAPITAL	CAPITAL	CAPITAL	CE RATIO	CE RATIO	CE RATIO	CE RATIO	CE RATIO	CE RATIO	CE RATIO	CE RATIO	LTD RATIO	LTD RATIO	LTD RATIO	LTD RATIO	LTD RATIO	LTD RATIO	LTD RATIO	LTD RATIO	STD RATIO	STD RATIO	STD RATIO	STD RATIO	STD RATIO	STD RATIO	STD RATIO	STD RATIO
2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	2016Q3	2016Q2
3,410,625	3,410,312	3,327,079	3,291,028	3,270,228	60.38%	60.04%	59.73%	59.16%	58.71%	56.92%	56.90%	56.63%	39.62%	39.96%	40.27%	40.84%	41.29%	43.08%	43.10%	43.37%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
777,867	745,916	732,172	726,861	720,000	54.68%	55.69%	54.96%	55.01%	53.08%	52.20%	51.85%	51.39%	45.32%	44.31%	45.04%	44.99%	46.92%	47.80%	48.15%	48.61%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
733,331	733,019	727,422	731,312	731,277	53.22%	53.49%	56.14%	53.26%	53.24%	52.88%	53.13%	53.13%	46.78%	46.51%	43.86%	46.74%	46.76%	47.12%	46.87%	46.87%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
432,243	432,463	433,010	431,764	431,066	53.46%	54.01%	53.16%	53.27%	53.29%	53.35%	53.22%	53.14%	46.54%	45.99%	46.84%	46.73%	46.71%	46.65%	46.78%	46.86%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
2,440,870	2,371,820	2,332,685	2,307,590	2,291,622	46.55%	48.18%	48.20%	45.25%	45.60%	46.83%	47.33%	44.87%	47.56%	48.29%	48.58%	49.01%	50.44%	51.29%	51.84%	52.20%	5.89%	3.53%	3.22%	5.74%	3.96%	1.89%	0.82%	2.92%
#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	56.18%	58.23%	58.00%	56.96%	57.68%	57.70%	57.60%	56.98%	40.11%	41.61%	41.81%	41.65%	42.27%	42.30%	41.71%	41.81%	3.71%	0.16%	0.19%	1.39%	0.05%	0.00%	0.68%	1.21%
3,785,887	3,764,746	3,782,494	3,760,800	3,705,872	51.37%	54.22%	54.22%	53.48%	53.22%	52.84%	53.15%	52.46%	48.63%	45.78%	45.78%	46.52%	46.78%	46.58%	46.85%	47.54%	0.00%	0.00%	0.00%	0.00%	0.00%	0.58%	0.00%	0.00%
4,619,281	4,483,069	4,476,832	4,363,989	4,029,927	49.92%	50.31%	51.75%	50.89%	50.12%	50.24%	48.99%	50.54%	50.08%	49.69%	48.17%	49.11%	49.67%	49.76%	51.01%	49.46%	0.00%	0.00%	0.08%	0.00%	0.21%	0.00%	0.00%	0.00%
3,818,863	3,744,708	3,783,636	3,677,713	3,671,576	47.48%	45.83%	45.40%	44.74%	45.64%	44.30%	44.83%	44.33%	52.52%	46.03%	47.51%	47.31%	48.24%	47.75%	49.12%	48.67%	0.00%	8.14%	7.09%	7.95%	6.11%	7.95%	6.04%	6.99%
6,362,166	6,114,929	5,798,065	5,816,545	5,721,367	53.59%	53.36%	53.05%	52.75%	53.46%	56.09%	56.23%	55.50%	46.41%	46.64%	46.95%	47.25%	46.54%	43.91%	43.77%	44.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3,126,225	3,074,800	3,099,010	3,083,587	3,101,638	46.20%	45.48%	47.58%	46.32%	46.13%	45.11%	45.44%	43.06%	53.80%	53.25%	52.42%	52.47%	53.34%	52.92%	53.19%	52.88%	0.00%	1.27%	0.00%	1.22%	0.53%	1.97%	1.38%	4.06%
72,521	72,081	70,739	71,701	71,466	65.80%	64.99%	62.33%	62.08%	61.85%	61.12%	61.65%	61.52%	34.20%	35.01%	37.67%	37.92%	38.15%	38.88%	38.35%	38.48%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!	#VALUE!
3,645,724	3,518,337	3,467,827	3,511,191	3,510,307	49.18%	48.91%	49.22%	48.55%	50.12%	50.44%	52.20%	51.22%	50.03%	50.45%	44.74%	45.62%	47.29%	48.05%	47.46%	47.48%	0.78%	0.64%	6.05%	5.83%	2.59%	1.51%	0.34%	1.30%

Company Name	Ticker	2020-22 2021-23 Return on Com Equity	2020-22 2021-23 All Div'ds to Net Prof	Retention Ratio ("B")	B x R	2017 2018 Common Shs Outst'g	2020-22 2021-23 Common Shs Outst'g	2018 High Price	2018 Low Price	2018 Midpoint	2018 Book Value per sh	M/B Ratio	S	V	BR + SV
Atmos Energy Corporation	ATO	11.00%	49.00%	51.00%	5.61%	114.00	130.00	86.1	76.5	81.3	42.1	1.93	8.55%	48.22%	9.73%
Chesapeake Utilities Corporation	CPK	11.50%	38.00%	62.00%	7.13%	17.00	20.00	78.9	66.9	72.9	30.7	2.37	13.08%	57.89%	14.70%
Spire Inc	SR	9.50%	54.00%	46.00%	4.37%	48.50	50.00	75.3	60.1	67.7	43.75	1.55	1.56%	35.38%	4.92%
New Jersey Resources Corporation	NJR	13.00%	42.00%	58.00%	7.54%	86.50	86.50	40.4	35.6	38	15.95	2.38	0.00%	58.03%	7.54%
NiSource Inc.	NI	12.00%	67.00%	33.00%	3.96%	340.00	350.00	25.7	22.4	24.05	13.65	1.76	1.69%	43.24%	4.69%
Northwest Natural Gas Company	NWN	11.00%	63.00%	37.00%	4.07%	29.50	30.00	59.3	52.5	55.9	30.45	1.84	1.02%	45.53%	4.53%
ONE Gas, Inc.	OGS	9.00%	63.00%	37.00%	3.33%	52.50	55.00	73.6	64.1	68.85	38.4	1.79	2.77%	44.23%	4.56%
South Jersey Industries, Inc.	SJI	11.00%	60.00%	40.00%	4.40%	81.00	85.00	31.5	26.2	28.85	16.35	1.76	2.83%	43.33%	5.63%
Southwest Gas Corporation	SWX	8.50%	51.00%	49.00%	4.17%	49.00	53.00	81.2	66.6	73.9	39.8	1.86	4.87%	46.14%	6.41%
UGI Corporation	UGI	11.50%	36.00%	64.00%	7.36%	173.00	173.00	48	42.5	45.25	19.65	2.30	0.00%	56.57%	7.36%
WGL Holdings, Inc.	WGL	11.00%	70.00%	30.00%	3.30%	53.00	55.00	86.7	83.4	85.05	32.95	2.58	3.17%	61.26%	5.24%
ALLETE, Inc.	ALE	8.50%	64.00%	36.00%	3.06%	52.00	56.00	74.4	66.6	70.5	42.1	1.67	4.15%	40.28%	4.73%
Alliant Energy Corporation	LNT	11.50%	64.00%	36.00%	4.14%	233.00	235.00	42.7	36.8	39.75	19	2.09	0.59%	52.20%	4.45%
Ameren Corporation	AEE	10.00%	60.00%	40.00%	4.00%	244.00	250.00	59	51.9	55.45	31	1.79	1.44%	44.09%	4.63%
American Electric Power Company, Inc.	AEP	10.50%	63.00%	37.00%	3.89%	493.50	516.00	73.4	63.3	68.35	38.7	1.77	2.62%	43.38%	5.02%
Avangrid, Inc.	AGR	5.50%	67.00%	33.00%	1.82%	309.00	309.00	50.9	45.2	48.05	49.9	0.96	0.00%	-3.85%	1.82%
Avista Corporation	AVA	8.50%	65.00%	35.00%	2.98%	67.00	70.00	52.3	47.5	49.9	26.95	1.85	2.70%	45.99%	4.21%
Black Hills Corporation	BKH	10.00%	60.00%	40.00%	4.00%	59.50	59.50	60.2	50.5	55.35	35.25	1.57	0.00%	36.31%	4.00%
CenterPoint Energy, Inc.	CNP	14.50%	64.00%	36.00%	5.22%	431.00	435.00	28.5	25.8	27.15	11.35	2.39	0.73%	58.20%	5.65%
CMS Energy Corporation	CMS	13.50%	61.00%	39.00%	5.27%	284.00	294.00	47.4	40.5	43.95	16.95	2.59	2.98%	61.43%	7.09%
Consolidated Edison, Inc.	ED	8.50%	67.00%	33.00%	2.81%	312.00	316.00	84.9	74.6	79.75	50.15	1.59	0.67%	37.12%	3.05%
Dominion Energy Inc.	D	16.50%	86.00%	14.00%	2.31%	654.00	670.00	81.7	72.8	77.25	28.4	2.72	2.18%	63.24%	3.69%
DTE Energy Company	DTE	11.00%	61.00%	39.00%	4.29%	182.50	195.00	110.5	97.7	104.1	55.95	1.86	4.11%	46.25%	6.19%
Duke Energy Corporation	DUK	8.50%	78.00%	22.00%	1.87%	702.00	706.00	84.4	72.9	78.65	60.45	1.30	0.24%	23.14%	1.93%
Edison International	EIX	12.50%	58.00%	42.00%	5.25%	325.81	325.81	67.6	57.6	62.6	37.35	1.68	0.00%	40.34%	5.25%
El Paso Electric Company	EE	9.00%	61.00%	39.00%	3.51%	40.60	41.00	55.8	48.1	51.95	29.2	1.78	0.58%	43.79%	3.76%
Entergy Corporation	ETR	12.00%	58.00%	42.00%	5.04%	183.00	193.00	83	71.9	77.45	45.75	1.69	3.00%	40.93%	6.27%
Exelon Corporation	EXC	8.50%	51.00%	49.00%	4.17%	962.00	978.00	39.9	35.6	37.75	32.75	1.15	0.63%	13.25%	4.25%
FirstEnergy Corp.	FE	12.50%	53.00%	47.00%	5.88%	478.00	548.00	34.1	29.3	31.7	17.45	1.82	8.38%	44.95%	9.64%
Great Plains Energy Inc.	GXP	10.50%	62.00%	38.00%	3.99%	216.00	158.00	32.4	28.5	30.45	23.1	1.32	-12.92%	24.14%	0.87%
Hawaiian Electric Industries, Inc.	HE	10.00%	59.00%	41.00%	4.10%	108.80	113.00	36.2	31.7	33.95	19.95	1.70	2.14%	41.24%	4.98%
IDACORP, Inc.	IDA	9.00%	63.00%	37.00%	3.33%	50.40	50.40	91.4	79.6	85.5	46.4	1.84	0.00%	45.73%	3.33%
MGE Energy, Inc.	MGEE	10.00%	48.00%	52.00%	5.20%	35.00	36.00	63.3	51.1	57.2	23.7	2.41	2.25%	58.57%	6.52%
NextEra Energy, Inc.	NEE	14.00%	56.00%	44.00%	6.16%	500.00	535.00	159.6	147.1	153.35	61.9	2.48	5.59%	59.63%	9.50%
Eversource Energy	ES	10.00%	58.00%	42.00%	4.20%	316.89	316.89	65	56.8	60.9	36.3	1.68	0.00%	40.39%	4.20%
NorthWestern Corporation	NWE	9.50%	64.00%	36.00%	3.42%	50.25	51.00	59.8	50	54.9	37.95	1.45	0.71%	30.87%	3.64%
OGE Energy Corp.	OGE	11.00%	74.00%	26.00%	2.86%	199.70	199.70	33.1	29.6	31.35	19.95	1.57	0.00%	36.36%	2.86%
Otter Tail Corporation	OTTR	10.00%	63.00%	37.00%	3.70%	40.00	44.00	44.9	39	41.95	18.75	2.24	7.15%	55.30%	7.65%
PG&E Corporation	PCG	9.00%	54.00%	46.00%	4.14%	520.00	550.00	47	37.3	42.15	41.05	1.03	1.92%	2.61%	4.19%
Pinnacle West Capital Corporation	PNW	10.50%	63.00%	37.00%	3.89%	112.00	113.00	85.6	73.8	79.7	46.35	1.72	0.51%	41.84%	4.10%
PNM Resources, Inc.	PNM	9.50%	50.00%	50.00%	4.75%	79.65	79.65	40.6	33.8	37.2	21.9	1.70	0.00%	41.13%	4.75%
Portland General Electric Company	POR	9.00%	63.00%	37.00%	3.33%	89.25	90.00	45.6	39	42.3	27.85	1.52	0.42%	34.16%	3.47%
PPL Corporation	PPL	13.50%	68.00%	32.00%	4.32%	700.00	740.00	32.4	29.2	30.8	16.15	1.91	3.53%	47.56%	6.00%
Public Service Enterprise Group Incorporated	PEG	10.50%	65.00%	35.00%	3.68%	506.00	506.00	51.9	46.6	49.25	28.75	1.71	0.00%	41.62%	3.68%
SCANA Corporation	SCG	7.00%	40.00%	60.00%	4.20%	142.90	142.90	49.4	35.3	42.35	44.3	0.96	0.00%	-4.60%	4.20%
Sempra Energy	SRE	11.00%	63.00%	37.00%	4.07%	279.00	296.00	113.5	100.6	107.05	58.2	1.84	3.63%	45.63%	5.72%
Southern Company	SO	13.00%	72.00%	28.00%	3.64%	1008.00	1016.00	48.1	42.6	45.35	24.5	1.85	0.48%	45.98%	3.86%
Vectren Corporation	VVC	12.50%	64.00%	36.00%	4.50%	83.50	86.00	65.4	58	61.7	23.6	2.61	2.56%	61.75%	6.08%
Westar Energy, Inc.	WR	11.00%	56.00%	44.00%	4.84%	142.50	145.00	53.3	47.1	50.2	28.35	1.77	1.02%	43.53%	5.28%
WEC Energy Group, Inc.	WEC	12.00%	66.00%	34.00%	4.08%	315.60	315.60	66.4	58.9	62.65	30.95	2.02	0.00%	50.60%	4.08%
Xcel Energy Inc.	XEL	10.50%	63.00%	37.00%	3.89%	509.50	522.50	48.4	41.5	44.95	23.55	1.91	1.59%	47.61%	4.64%

Source: Value Line

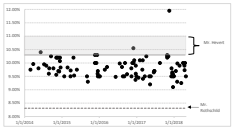
Company	Ticker	State	Fuel/ Purchased Power	Decoupling (F/P) [1]	New Capital Investment [2]	Energy Efficiency [3]	Renewables & RPS [4]	Environmental [5]	Other [6]
ALLETE (Minnesota Power)	ALE	MN	Fuel and Purch Energy Adj			Conservation Program Adj.	Rewable Resource Rider	AREA Rider (Arrowhead Reg Emission Abatement); Boswell Unit 4 Emission Reduction,	Transmission Cost recovery, Franchise fees, CARE Rider (uncollectibles/arrearage program)
Superior Water, Light and Power Company	ALE	WI	Power Cost Adj. Clause						
Black Hills Colorado Electric Utility Company, LP	BKH	CO	Energy Cost Adj, Purch Capacity Cost Adj,		Clean Air Clean Jobs Act (Capital costs of LM6000 Plant)	DSM Adj	Renewable Energy Standard Adj		Tax/Fee Adj, Transmission Cost Adj, BHEAP (low Income),
Black Hills Power, Inc.	BKH	SD	Fuel and PPA Adj	Partial - EE Solutions Adj (recovers lost revenues)	Transmission Facility Adj (new or modified transmission facilities)	EE Solutions Adj		Env Improvement Adj.; Fuel PPA recovers cost of chemical reagents,	Transmission Cost Adj,
Black Hills Power, Inc.	BKH	WY	Energy Cost Adj.						
Cheyenne Light, Fuel and Power Company	BKH	WY	Power Cost Adj. Clause	Partial - DSM Adj allows for margin recovery		DSM			Franchise Fee
El Paso Electric Company	EE	NM	FPPCAC			EUERF			Taxes & Fees
El Paso Electric Company	EE	TX	Fixed Fuel Factor			EECRF			Military Base discount recovery; Taxes; University discount rider; Rate Case Expense;
Hawaii Electric Light Company, Inc.	HE	HI	Energy Cost Adj. Clause; Purchase Power Adj. Clause	Full - Rate Adj. Mechanism	*Cost of Service Recovery Mechanism (not in tariff)	Public Benefits Surcharge; IRP/DSM Cost Recovery	Green Infrastructure Fee (collects funds for state agency to secure and repay gonds issued under Green Energy Market Securitization program)		IRP/ DSM Cost Recovery
Hawaiian Electric Company, Inc.	HE	HI	Energy Cost Adj. Clause; Purchase Power Adj. Clause	Full - Rate Adj. Mechanism	*Cost of Service Recovery Mechanism (not in tariff)	Public Benefits Surcharge; IRP/DSM Cost Recovery	Renewable Energy Infrastructure Cost Recovery; Green Infrastructure Fee		IRP/ DSM Cost Recovery
Maui Electric Company, Limited	HE	HI	Energy Cost Adj. Clause; Purchase Power Adj. Clause	Full - Rate Adj. Mechanism	Major Project Interim Recovery Mechanism; Cost of Service Recovery Mechanism	Public Benefits Surcharge; IRP/DSM Cost Recovery	Renewable Energy Infrastructure Cost Recovery; Green Infrastructure Fee		IRP/ DSM Cost Recovery
Idaho Power Co.	IDA	ID	Power Cost Adj. Clause	Full - Fixed Cost Recovery Rate		EE Rider			Municipal Franchise Fees
Idaho Power Co.	IDA	OR	Power Cost Adj. Mechanism			EE Rider	Solar PV Rider (pilot)	Boardman Plant (coal) shutdown cost recovery	Municipal Franchise Fees
Interstate Power and Light Company	LNT	IA	Energy Adj. Clause			EECR	Rider AEP (Alt Energy Prod)	Energy Adj. Clause (recovers allowance costs)	Tax Adj; RTO/Regional Transmission Service;
Wisconsin Power and Light Company	LNT	WI	Fuel Adjustment Clause						
NorthWestern Corporation	NWE	MT	Electric Supply Service ESS-1;			Universal System Benefits Charge			Electric Supply Service ESS-1 (transmission); USBC (low Income); Taxes; Transition Costs (CTC)
NorthWestern Corporation	NWE	SD	Adjustment Clause			EE		Adj Clause recovers chemical reagent costs	Ad Valorem Taxes (Electric Adj Clause); Tax Adj. Clause; Transmission Costs; Muni Taxes/Franchise Fees
Oklahoma Gas and Electric Company	OGE	AR	Energy Cost Recovery Rider	Partial - EE Cost Recovery Rider recovers LCFC	Formula Rate Plan recovers incremental CapEx	EE Cost Recovery Rider		Environmental Compliance Plan	

Oklahoma Gas and Electric Company	OGE	OK	Fuel Cost Adj.	Partial - DPR includes recovery of LCFC		Demand Program Rider;			Public Utility Assessment (OCC Charge); Storm Cost Recovery; SPP Cost Recovery (Transmission); Public Utility Assessment
Public Service Company of New Mexico	PNM	NM	FPPCAC			EE Rider	Renewable Energy Rider (RPS compliance costs)		Municipal Undergrounding costs
Texas New Mexico Power	PNM	TX			TCRF (transmission capital investment); Rider AMS (AMI meters)	Rider EECRF; Rider SBF (Funds low-income EE)			TCRF (transmission cost recovery), Municipal Franchise Fee Adj; Rider SBF (low-income)
Otter Tail Power Company	OTTR	ND	Energy Adj. Rider		Transmission Cost Recovery Rider (transmission capital investment)		Renewable Resource Cost Recovery	Environmental Cost Recovery Rider	Economic Development Cost Removal Rider; Energy Adj. Rider (MISO transmission charges);

Rate Case History (Past Rate Cases) Source: Regulatory Research Associates

Portfolio None
Consumr List All
States All
Years All
Service Type Electric

State	Company	Ticker	Docket	Rate Case Service Type	Case Type	Date	Rate Increase ($M)	Rate Increase (%)	Return on Original Cost Rate (%)	Return on Equity (%)	Common Equity to Total Capital (%)	Rate Base ($M)	Date	Decision Type	Rate Increase ($M)	Phase-In?	Interim Authorized?	Return on Original Cost Rate (%)	Return on Equity (%)	Common Equity to Total Capital (%)	Test Year End Date	Rate Case Rate Base ($M)	Rate Base Valuation Method	Rate Case Duration (months)	Authorized	Hoch Low Hevert	10.00% 10.60% Rothschild
North Dakota	Northern States Power Co. - MN	XEL	C-PU-12-813	Electric	Vertically Integrated	12/18/2012	14.9	7.72	10.25	52.56	375.81	2/26/2014	Settled	9.0	Yes		7.45	9.75	52.56	NA		NA	NA	14	9.75%	1/1/2014	10.30%	8.31%
New Mexico	Southwestern Public Service Co	XEL	C-12-00350-UT	Electric	Vertically Integrated	12/12/2012	21.0	8.41	10.25	53.89	469.41	3/26/2014	Fully Litigated	12.7	No		8.26	9.96	53.89	12/2014		NA	Average	15	9.96%	3/26/2014	10.30%	8.31%
Texas	Entergy Texas Inc.	ETR	D-41791	Electric	Vertically Integrated	9/25/2013	38.6	8.51	10.40	48.59	1,633.82	5/16/2014	Settled	18.5	No	Yes	NA	9.80	NA	03/2013		NA	NA	7	9.80%	5/16/2014	10.30%	8.31%
Wisconsin	Wisconsin Power and Light Co	LNT	6680-UR-119 (Elec)	Electric	Vertically Integrated	4/8/2014	0.0	NA	10.40	50.48	2,159.11	6/9/2014	Fully Litigated	0.0	No	No	NA	10.40	50.48	12/2013		2,159.11	Average	5	10.40%	6/9/2014	10.30%	8.31%
Louisiana	Entergy Louisiana LLC	ETR	D-41791	Electric	Vertically Integrated	5/28/2013	11.4	8.19	10.45	52.95	1,396.73	7/30/2014	Settled	9.5	Yes	No	NA	9.95	NA	NA		NA	NA	15	9.95%	7/10/2014	10.30%	8.31%
Wyoming	Cheyenne Light Fuel Power Co.	XEL	D-20000-578-ER-13	Electric	Vertically Integrated	12/3/2013	17.8	8.59	10.25	52.09	376.09	7/7/2014	Settled	8.4	No	No	7.98	9.65	52.09	06/2013		376.67	Year-end	8	9.90%	7/31/2014	10.30%	8.31%
Vermont	Green Mountain Power Corp.		D-8190, 8191	Electric	Vertically Integrated	12/20/2013	-0.2	7.61	10.00	48.97	1,187.00	8/25/2014	Settled	-8.8	No	No	7.46	9.60	50.00	09/2013		1,164.74	Average	8	9.60%	8/25/2014	10.30%	8.31%
Utah	PacifiCorp	BRK.A	D-13-035-184	Electric	Vertically Integrated	1/3/2014	76.3	7.72	10.00	51.80	6,039.33	8/29/2014	Settled	54.2	Yes		7.57	9.80	51.43	08/2013		NA	NA	7	9.80%	8/29/2014	10.30%	8.31%
Florida	Florida Public Utilities Co.	CPK	D-140025-EI	Electric	Vertically Integrated	4/28/2014	5.9	7.18	11.25	46.47	60.60	9/15/2014	Settled	3.8	No	Yes	NA	10.25	NA	09/2015		NA	NA	4	10.25%	9/15/2014	10.30%	8.31%
Nevada	Nevada Power Co.	BRK.A	D-14-05004	Electric	Vertically Integrated	5/2/2014	37.8	8.25	10.12	48.17	5,249.68	10/9/2014	Settled	0.0	No	No	8.09	9.80	48.17	12/2013		NA	NA	5	9.80%	10/9/2014	10.30%	8.31%
Illinois	MidAmerican Energy Co.	BRK.A	D-14-0066	Electric	Vertically Integrated	12/16/2013	20.9	7.72	10.70	51.73	334.84	11/6/2014	Fully Litigated	16.4	No	No	7.14	9.56	51.73	12/2012		334.12	Year-end	10	9.56%	11/6/2014	10.30%	8.31%
Wisconsin	Wisconsin Public Service Corp	WEC	6690-UR-120 (Elec)	Electric	Vertically Integrated	4/1/2014	78.8	8.77	10.40	50.50	1,579.78	11/6/2014	Fully Litigated	54.6	No	No	8.56	10.35	50.58	12/2013		1,580.67	Average	7	10.20%	11/6/2014	10.30%	8.31%
Wisconsin	Wisconsin Electric Power Co	WEC	6690-UR-120 (Elec)	Electric	Vertically Integrated	4/1/2014	78.8	8.65	10.35	51.95	4,439.84	11/6/2014	Fully Litigated	54.6	No	No	8.65	10.35	51.95	12/2013		4,457.94	Average	7	10.20%	11/14/2014	10.30%	8.31%
Virginia	Appalachian Power Co.	AEP	D-PUE-2014-00096	Electric	Vertically Integrated	5/31/2014	0.0	7.27	10.50	45.14	2,727.98	11/26/2014	Fully Litigated	0.0	No	No	6.88	9.75	45.69	12/2013		NA	NA	6	9.75%	11/26/2014	10.30%	8.31%
Wisconsin	Madison Gas and Electric Co.	MGEE	5-UR-108 (Elec)	Electric	Vertically Integrated	4/17/2014	11.5	8.07	10.35	50.95	535.19	11/26/2014	Fully Litigated	11.4	No	No	7.96	10.35	50.96	12/2013		535.85	Average	7	10.20%	11/26/2014	10.30%	8.31%
Texas	Entergy Gulf States Power Co.	ETR	D-41791	Electric	Vertically Integrated	9/25/2013	7.78	10.00	50.48	2,705.19	1,579.78	11/26/2014	Fully Litigated	44.5	No	No	7.56	9.68	49.45	12/2013		2,705.27	Average	9	9.68%	12/4/2014	10.30%	8.31%
Mississippi	Entergy Mississippi Inc.	ETR	D-2014-UN-0132	Electric	Vertically Integrated	6/30/2014	204.54181	7.81	10.59	NA	2022.490016	12/11/2014	Settled	177.658	No	No	7.51	10.07	NA	12/2015		2014.338539	Average	6	10.07%	12/11/2014	10.30%	8.31%
Wisconsin	Northern States Power Co - WI	XEL	D-4220-UR-120 (Elec)	Electric	Vertically Integrated	4/29/2014	20.6	NA	10.2	52.54	NA	12/12/2014	Fully Litigated	14.177	No	No	NA	10.2	52.54	12/2015	NA	NA	Average	6	10.20%	12/12/2014	10.30%	8.31%
Colorado	Black Hills Colorado Electric	BKH	D-14AL-0393E	Electric	Vertically Integrated	4/30/2014	13.205396	7.83	10.3	50.54	457.778447	12/18/2014	Fully Litigated	9.2	No	No	7.55	9.83	49.83	12/2013		448.334572	Average	7	9.83%	12/18/2014	10.30%	8.31%
Wyoming	PacifiCorp	BRK.A	D-20000-469-ER-14	Electric	Vertically Integrated	5/30/2014	33.924507	7.67	10	51.43	3977.88756	12/30/2014	Fully Litigated	39.188277	No	No	7.41	9.5	51.43	06/2013		3967	Average	10	9.50%	12/30/2014	10.30%	8.31%
Colorado	Public Service Co. of CO	XEL	D-14AL-0660E	Electric	Vertically Integrated	6/27/2014	78.467475	7.79	10.25	NA	4388.19887	2/24/2015	Settled	-29.49815	No	Yes	7.55	9.83	NA	12/2015	NA	NA	Year-end	8	9.83%	2/24/2015	10.30%	8.31%
Washington	PacifiCorp	BRK.A	D-UE-140762	Electric	Vertically Integrated	5/12/2014	30.4	7.67	10	51.73	829	3/25/2015	Fully Litigated	9.568464	No	No	7.3	9.5	49.1	12/2013		818.890601	Average	10	9.50%	3/25/2015	10.30%	8.31%
Minnesota	Northern States Power Co. - MN	XEL	E-002/GR-13-868	Electric	Vertically Integrated	11/4/2013	248.12	7.65	10.25	52.5	7042	3/26/2015	Fully Litigated	149.419	Yes	Yes	7.37	9.72	52.5	12/2014		6986.289	Average	16	9.72%	3/26/2015	10.30%	8.31%
Michigan	Wisconsin Public Service Corp.	WEC	U-17669	Electric	Vertically Integrated	10/17/2014	5.651277	6.21	10.6	40.82	61.24749	4/23/2015	Settled	4.619475	Yes		6.01	10.2	NA	12/2015	NA	NA	NA	6	10.20%	4/23/2015	10.30%	8.31%
Missouri	Union Electric Co.	AEE	E-ER-2014-0258	Electric	Vertically Integrated	7/3/2014	181.22716	8.05	10.4	51.76	6976.38643	4/29/2015	Fully Litigated	121.54475	No	No	7.6	9.53	51.76	03/2014		6976.276139	Year-end	10	9.53%	4/29/2015	10.30%	8.31%
West Virginia	Appalachian Power Co.	AEP	C-14-1152-E-42T	Electric	Vertically Integrated	6/30/2014	226.1095	7.79	10.62	47.16	3992.888495	5/26/2015	Fully Litigated	123.457711	No	No	7.38	9.75	47.16	12/2013		3760.116889	Average	11	9.75%	5/26/2015	10.30%	8.31%
Missouri	Kansas City Power & Light	GXP	E-ER-2014-0370	Electric	Vertically Integrated	10/30/2014	112.70772	7.93	10.3	50.09	2584.137965	9/2/2015	Fully Litigated	89.671644	No	No	7.53	9.5	50.09	03/2014		2580.074221	Year-end	10	9.50%	9/2/2015	10.30%	8.31%
Kansas	Kansas City Power & Light	GXP	D-15-KCPE-116-RTS	Electric	Vertically Integrated	1/7/2015	56.278815	7.94	10.3	50.48	2087.48033	9/10/2015	Fully Litigated	40.125638	No	No	7.44	9.3	50.48	09/2014		2115.959865	Year-end	8	9.30%	9/10/2015	10.30%	8.31%
Wisconsin	Wisconsin Public Service Corp.	WEC	6690-UR-124 (Elec)	Electric	Vertically Integrated	4/7/2015	96.870963	8.27	10.2	50.52	1840.568558	11/19/2015	Fully Litigated	-7.874	No	No	8.24	10	50.47	12/2016		1745.688	Average	7	10.00%	11/19/2015	10.30%	8.31%
Michigan	Consumers Energy Co	CMS	U-17735	Electric	Vertically Integrated	1/29/2014	198.556	6.38	10.7	41.5	9247.692	11/19/2015	Fully Litigated	126.336	Yes	Yes	6.18	10.3	41.5	09/2016		9160.088	Average	11	10.30%	11/19/2015	10.30%	8.31%
Wisconsin	Northern States Power Co - WI	XEL	D-4220-UR-121 (Elec)	Electric	Vertically Integrated	4/29/2015	27.388453	8.07	10.2	52.59	1188.88761	12/3/2015	Fully Litigated	7.598	No	No	7.81	10	52.49	12/2016		1175.225	Average	6	10.00%	12/3/2015	10.30%	8.31%
Michigan	DTE Electric Co.	DTE	U-17767	Electric	Vertically Integrated	1/29/2014	348.737	5.87	10.75	38.03	13549.146	12/11/2015	Fully Litigated	242.680277	No	Yes	5.7	10.3	38.03	09/2016		13431.968	Average	11	10.30%	12/11/2015	10.30%	8.31%
Oregon	Portland General Electric Co.	POR	D-UE-294	Electric	Vertically Integrated	3/23/2015	122.336	7.67	9.9	50	4470.484	12/15/2015	Settled	70.4	Yes	No	7.51	9.6	50	12/2016		4440.305	Average	10	9.60%	12/15/2015	10.30%	8.31%
Texas	Southwestern Public Service Co	XEL	D-42885	Electric	Vertically Integrated	1/29/2014	42.074996	8.28	10.25	53.97	1538.377121	12/17/2015	Fully Litigated	-4.029973	No	No	7.88	9.7	51	09/2014		1394.571637	Year-end	12	9.70%	12/17/2015	10.30%	8.31%
Idaho	Avista Corp.	AVA	C-AVU-E-15-05	Electric	Vertically Integrated	6/1/2015	26.943	7.62	9.9	50	766.971	12/18/2015	Settled	1.7	No	No	7.42	9.5	50	12/2014		735.02	Average	6	9.50%	12/18/2015	10.30%	8.31%
Wyoming	PacifiCorp	BRK.A	D-20000-469-ER-15	Electric	Vertically Integrated	5/29/2015	26.934063	7.6	9.85	51.44	2120.357569	12/30/2015	Fully Litigated	16.259853	No	No	7.41	9.5	51.44	12/2015		2087.281107	Average	10	9.50%	12/30/2015	10.30%	8.31%
Washington	Avista Corp.	AVA	D-UE-150204	Electric	Vertically Integrated	2/9/2015	33.229	7.46	9.9	48	1464.296	1/6/2016	Settled	-8.11	No	No	7.29	9.5	48.5	09/2014		1315.891	NA	11	9.50%	1/6/2016	10.30%	8.31%
Arkansas	Entergy Arkansas Inc.	ETR	D-15-015-U	Electric	Vertically Integrated	4/24/2015	268.463	4.86	10.2	30.16	5928.760863	2/23/2016	Settled	219.675858	No	No	4.52	9.75	28.46	03/2015	NA	NA	NA	10	9.75%	2/23/2016	10.30%	8.31%
Indiana	Indianapolis Power & Light Co.	AES	Ca-44576	Electric	Vertically Integrated	12/29/2014	65.625	6.91	10.93	37.33	1964.992	3/16/2016	Fully Litigated	29.622	No	No	6.51	9.85	37.33	09/2014		1887.305	Year-end	14	9.85%	3/16/2016	10.30%	8.31%
New Mexico	El Paso Electric Co.	EE	C-15-00312-UT	Electric	Vertically Integrated	5/1/2015	6.47277	7.9	9.96	49.76	476.95756	6/8/2016	Fully Litigated	1.09542	NA	No	7.67	9.48	48.75	12/2014		414.483956	Year-end	13	9.48%	6/8/2016	10.30%	8.31%
Indiana	Northern Indiana Pub. Svc. Co.	NI	Ca-44688	Electric	Vertically Integrated	5/1/2015	116.49645	8.78	10.75	45.3	3427.72173	7/19/2016	Settled	77.5	No	No	6.74	9.98	47.47	12/2015		3221.417887	Year-end	9	9.98%	7/19/2016	10.30%	8.31%
Tennessee	Kingsport Power Company	AEP	D-15-00001	Electric	Vertically Integrated	1/4/2016	13.118373	6.66	10.66	47.43	71.59984	8/8/2016	Settled	8.618586	No	No	6.18	9.85	45.75	12/2017		87.748426	Average	7	9.85%	8/8/2016	10.30%	8.31%
Arizona	UNS Electric Inc.	FTS	D-E-04204A-15-0142	Electric	Vertically Integrated	5/5/2015	15.1	7.22	9.5	52.83	270.29278	8/18/2016	Fully Litigated	15.1	No	No	7.22	9.5	52.83	12/2014		270.293	Year-end	17	9.50%	8/18/2016	10.30%	8.31%
Washington	PacifiCorp	BRK.A	D-UE-152253	Electric	Vertically Integrated	11/25/2015	20.3	7.3	9.5	49.1	874.15294	9/1/2016	Fully Litigated	13.675337	Yes	No	7.3	9.5	49.1	06/2015		808.328129	Year-end	9	9.50%	9/1/2016	10.30%	8.31%
Michigan	Upper Peninsula Power Co.		C-U-17895	Electric	Vertically Integrated	9/18/2015	8.459865	7.87	10.75	54.13	241.548024	9/8/2016	Fully Litigated	4.647975	No	Yes	7.47	10	53.49	12/2016		242.343919	Average	11	10.00%	9/8/2016	10.30%	8.31%
New Mexico	Public Service Co. of NM	PNM	C-15-00261-UT	Electric	Vertically Integrated	8/27/2015	123.49861	8.17	10.5	49.61	2458.087082	9/28/2016	Fully Litigated	61.2	No	No	7.71	9.58	49.61	09/2016		2363	Average	13	9.58%	9/28/2016	10.30%	8.31%
Wisconsin	Madison Gas and Electric Co.	MGEE	D-3270-UR-121 (Elec)	Electric	Vertically Integrated	4/8/2016	6.896	8.32	10.2	58.06	573.368	11/9/2016	Fully Litigated	-3.337	No	No	7.89	9.8	57.16	12/2017		570.778	Average	7	9.80%	11/9/2016	10.30%	8.31%
Oklahoma	Public Service Co. of OK	AEP	CA-PUD201500208	Electric	Vertically Integrated	7/1/2015	84.361751	7.6	10.5	48	2062.158915	11/10/2016	Fully Litigated	14.466574	No	Yes	6.94	9.5	44	01/2015		2024.773269	Year-end	16	9.50%	11/10/2016	10.30%	8.31%
Wisconsin	Wisconsin Power and Light Co	LNT	D-6680-UR-120 (Elec)	Electric	Vertically Integrated	5/20/2016	12.932	7.91	10	52.2	2851.381	11/18/2016	Settled	9.443	Yes	No	7.91	10	52.2	12/2018		2851.381	Average	6	10.00%	11/18/2016	10.30%	8.31%
Florida	Florida Power & Light Co.	NEE	D-160021-EI	Electric	Vertically Integrated	3/15/2016	1304.617	6.7	11.5	45.35	33893.496	11/29/2016	Settled	811	Yes	No	NA	10.55	NA	12/2018	NA	NA	NA	8	10.55%	11/29/2016	10.30%	8.31%
California	Liberty Utilities CalPeco Ele	AQN	A-15-06-005	Electric	Vertically Integrated	5/1/2015	11.4	7.92	10.5	52.5	150.927	12/1/2016	Settled	8.318	No	No	7.51	10	52.5	12/2016		145.662	Average	19	10.00%	12/1/2016	10.30%	8.31%
South Carolina	Duke Energy Progress LLC	DUK	D-2016-227-E	Electric	Vertically Integrated	7/1/2016	79	7.55	10.75	53	1316.993	12/7/2016	Settled	56.209	Yes	No	7.21	10.1	53	12/2015		1305.964	Year-end	5	10.10%	12/7/2016	10.30%	8.31%
Colorado	Black Hills Colorado Electric	BKH	D-16AL-0326E	Electric	Vertically Integrated	5/3/2016	14.4888	7.56	9.83	50.92	510.725287	12/16/2016	Fully Litigated	0.638267	No	No	7.43	9.37	52.39	12/2015		414.594839	Average	7	9.37%	12/16/2016	10.30%	8.31%
Nevada	Sierra Pacific Power Co.	BRK.A	D-16-06006	Electric	Vertically Integrated	6/6/2016	21.623	6.97	10.26	48.03	1852.549	12/22/2016	Settled	-2.923	No	No	6.65	9.6	48.03	12/2015	NA	NA	NA	6	9.60%	12/22/2016	10.30%	8.31%
North Carolina	Virginia Electric & Power Co.	D	E-22, Sub 532	Electric	Vertically Integrated	3/31/2016	46.752	7.8	10.5	53.92	1047.151	12/22/2016	Settled	34.732	No	Yes	7.37	9.9	51.75	12/2015		1040.035	Year-end	8	9.90%	12/22/2016	10.30%	8.31%
Idaho	Avista Corp.	AVA	C-AVU-E-16-03	Electric	Vertically Integrated	5/26/2016	15.433	7.78	9.9	50	754.636	12/28/2016	Settled	6.25	No	No	7.58	9.5	50	12/2015		754.003	Average	7	9.50%	12/28/2016	10.30%	8.31%
Wyoming	MDU Resources Group Inc.	MDU	D-20004-117-ER-16	Electric	Vertically Integrated	6/10/2016	3.225477	8	10.1	50.99	72.31157	1/18/2017	Settled	2.712246	NA	No	7.51	9.41	52.5	12/2016		72.207382	Year-end	7	9.45%	1/18/2017	10.30%	8.31%
Michigan	DTE Electric Co.	DTE	C-U-18014	Electric	Vertically Integrated	2/1/2016	325.245	5.71	10.5	37.49	14444.514	1/31/2017	Fully Litigated	184.336	No	Yes	5.55	10.1	37.49	07/2017		14243.719	Average	12	10.10%	1/31/2017	10.30%	8.31%
Arizona	Tucson Electric Power Co.	FTS	D-E-01933A-15-0322	Electric	Vertically Integrated	11/5/2015	109.534	7.34	10.35	50.03	2164.678	2/24/2017	Settled	81.5	No	No	7.04	9.75	50.03	09/2015		2045.20345	Year-end	15	9.75%	2/24/2017	10.30%	8.31%
Michigan	Consumers Energy Co.	CMS	U-17990	Electric	Vertically Integrated	3/1/2016	208.151	6.18	10.7	40.75	10187.09	2/28/2017	Fully Litigated	113.277	Yes	Yes	5.94	10.1	40.75	09/2017		10159.167	Average	12	10.10%	2/28/2017	10.30%	8.31%
Minnesota	Otter Tail Power Co.	OTTR	D-E-017/GR-15-1033	Electric	Vertically Integrated	2/16/2016	14.585079	7.85	10.05	52.5	482.364111	3/2/2017	Fully Litigated	12.29212	NA	No	7.51	9.41	52.5	12/2016		487.191827	Average	12	9.41%	3/2/2017	10.30%	8.31%
Oklahoma	Oklahoma Gas and Electric Co.	OGE	CA-PUD201500273	Electric	Vertically Integrated	12/18/2015	149.54645	8.09	10.25	53.31	4152.329406	3/20/2017	Fully Litigated	8.803215	No	Yes	7.69	9.5	53.31	06/2015		4202.129658	Year-end	15	9.50%	3/20/2017	10.30%	8.31%
Florida	Gulf Power Co.	SO	D-160186-EI	Electric	Vertically Integrated	10/12/2016	106.782	6.04	11	45.97	2418.917	4/4/2017	Settled	61.99	No	No	NA	10.25	NA	12/2017	NA	NA	NA	5	10.25%	4/4/2017	10.30%	8.31%
Missouri	Kansas City Power & Light	GXP	E-ER-2016-0285	Electric	Vertically Integrated	7/1/2016	65.150191	7.7	9.9	49.72	2529.30415	5/3/2017	Fully Litigated	32.531186	No	No	7.43	9.5	49.2	12/2015		2525.954938	Year-end	10	9.50%	5/3/2017	10.30%	8.31%
Minnesota	Northern States Power Co - MN	XEL	D-E-002/GR-15-826	Electric	Vertically Integrated	11/3/2015	207.723	7.43	10	52.5	7081.166	5/11/2017	Settled	144.779	Yes	No	7.08	9.7	52.5	12/2016		7207.754	Average	18	9.70%	5/11/2017	10.30%	8.31%
Arkansas	Oklahoma Gas and Electric Co.	OGE	D-16-052-U	Electric	Vertically Integrated	8/29/2016	15.19836	6.01	10.25	59.67	539.17816	6/28/2017	Settled	7.119836	No	No	5.43	9.5	58.38	06/2016		508.714857	Year-end	8	9.50%	6/28/2017	10.30%	8.31%
North Dakota	MDU Resources Group Inc.	MDU	C-PU-16-666	Electric	Vertically Integrated	10/14/2016	14.11436	7.46	10	50.73	521.90976	6/29/2017	Settled	7.509219	No	Yes	7.56	9.45	53.4	12/2017	NA	NA	Average	8	9.45%	6/29/2017	10.30%	8.31%
Kentucky	Kentucky Utilities Co.	PPL	C-2016-00370	Electric	Vertically Integrated	11/23/2016	103.09801	7.29	10.23	53.28	3638.80073	6/22/2017	Settled	51.58324	No	No	NA	9.7	NA	NA	NA	NA	NA	7	9.70%	6/22/2017	10.30%	8.31%
Kentucky	Louisville Gas & Electric Co.	PPL	C-2016-00371 (elec.)	Electric	Vertically Integrated	11/23/2016	93.630761	7.24	10.23	53.27	2404.580875	6/22/2017	Settled	57.098289	No	No	NA	9.7	NA	NA	NA	NA	NA	7	9.70%	6/22/2017	10.30%	8.31%
Arizona	Arizona Public Service Co.	PNW	D-E-01345A-16-0036	Electric	Vertically Integrated	6/1/2016	433.434	6.13	10.5	55.8	6771.151	8/15/2017	Settled	362.577	Yes	No	7.85	10	55.8	12/2015	NA	NA	Year-end	14	10.00%	8/15/2017	10.30%	8.31%
California	Pacific Gas and Electric Co.	PCG	Advice No. 3897-G/5148-E	Electric	Vertically Integrated	9/29/2017	-120	7.69	10.25	52	NA	10/26/2017	Settled	-120	No	No	7.69	10.25	52	12/2018	NA	NA	NA	0	10.25%	10/26/2017	10.30%	8.31%
California	San Diego Gas & Electric Co.	SRE	Advice No. 3120-E	Electric	Vertically Integrated	9/29/2017	-13.1	7.55	10.2	52	NA	10/26/2017	Settled	-13.1	No	No	7.55	10.2	52	12/2018	NA	NA	NA	0	10.20%	10/26/2017	10.30%	8.31%
California	Southern California Edison Co.	EIX	Advice No. 3695-E	Electric	Vertically Integrated	9/29/2017	-73	7.61	10.3	48	NA	10/26/2017	Settled	-73	No	No	7.61	10.3	48	12/2018	NA	NA	NA	0	10.30%	10/26/2017	10.30%	8.31%
Florida	Tampa Electric Co.	EMA	D-20170219-EI	Electric	Vertically Integrated	43005	0	NA	10.25	NA	NA	11/6/2017	Settled	0	Yes	No	NA	10.25	NA	NA	NA	NA	NA	1	10.25%	11/6/2017	10.30%	8.31%
Alaska	Alaska Electric Light Power	AVA	D-U-16-066	Electric	Vertically Integrated	42629	5.699894	9.98	13.8	58.18	123.036801	11/15/2017	Settled	3.389600	No	Yes	8.91	11.95	58.18	12/2015		123.029169	Average	14	11.95%	11/15/2017	10.30%	8.31%
Washington	Puget Sound Energy Inc.		D-UE-170033	Electric	Vertically Integrated	42748	144.03207	7.74	9.8	46.5	5097.74777	12/5/2017	Settled	106.368856	No	No	7.6	9.5	48.5	09/2016		5166.534272	Average	10	9.50%	12/5/2017	10.30%	8.31%
Wisconsin	Northern States Power Co - WI	XEL	D-4220-UR-123 (Elec)	Electric	Vertically Integrated	42859	24.739433	7.84	10	52.53	1216.975379	12/7/2017	Fully Litigated	9.418	No	No	7.56	9.8	51.45	12/2018		1194.763	Average	7	9.80%	12/7/2017	10.30%	8.31%
Texas	El Paso Electric Co.	EE	D-46831	Electric	Vertically Integrated	42779	39.24	8.14	10.5	48.35	1891.654	12/14/2017	Settled	14.5	Yes	No	7.73	9.65	48.35	09/2016	NA	NA	NA	10	9.65%	12/14/2017	10.30%	8.31%
Texas	Southwestern Electric Power Co	AEP	D-46449	Electric	Vertically Integrated	42720	105.92632	7.38	10	48.46	1238.892126	12/14/2017	Fully Litigated	86.899403	No	Yes	7.18	9.6	48.46	09/2016		1492.170959	Year-end	12	9.60%	12/14/2017	10.30%	8.31%
Oregon	Portland General Electric Co.	POR	D-UE-319	Electric	Vertically Integrated	42794	99.897	7.46	9.75	50	4594.052	12/18/2017	Settled	15.9	No	No	7.35	9.5	50	12/2018		4505.999	Year-end	9	9.50%	12/18/2017	10.30%	8.31%
New Mexico	Public Service Co. of NM	PNM	C-16-00276-UT	Electric	Vertically Integrated	42711	99.248874	7.51	10.13	49.61	2381.260297	12/20/2017	Settled	62.331355	No	No	7.58	9.58	49.61	12/2018	NA	NA	NA	12	9.58%	12/20/2017	10.30%	8.31%
Vermont	Green Mountain Power Corp.		C-17-3112-INV	Electric	Vertically Integrated	42839	31.709	7.67	9.5	48.63	1458.096	12/21/2017	Settled	31.915	No	No	6.87	9.1	48.6	12/2016		1433.244	Average	8	9.10%	12/21/2017	10.30%	8.31%
Idaho	Avista Corp.	AVA	D-AVU-E-17-01	Electric	Vertically Integrated	42885	28.507	7.81	9.9	50	811.595	12/28/2017	Settled	17.434	Yes	No	7.61	9.5	50	12/2016		794.982	Year-end	6	9.50%	12/28/2017	10.30%	8.31%
Nevada	Nevada Power Co.	BRK.A	D-17-06003	Electric	Vertically Integrated	42891	0	8.25	10	49.99	NA	12/29/2017	Fully Litigated	-28.567	No	No	8	9.51	49.99	12/2016		5010.152	Year-end	6	9.51%	12/29/2017	10.30%	8.31%
Kentucky	Kentucky Power Co.	AEP	C-2017-00179	Electric	Vertically Integrated	42914	60.397438	6.75	10.31	41.68	1191.785493	1/18/2018	Settled	12.34863	No	No	6.44	9.7	41.68	02/2017		1191.785493	Year-end	6	9.70%	1/18/2018	10.30%	8.31%
Oklahoma	Public Service Co. of OK	AEP	CA-PUD201700151	Electric	Vertically Integrated	42916	169.66753	7.22	10	48.5	2527.47526	1/31/2018	Fully Litigated	75.532909	No	No	6.88	9.3	48.51	12/2016		2465.222208	Year-end	7	9.30%	1/31/2018	10.30%	8.31%
Iowa	Interstate Power & Light Co	LNT	D-RPU-2017-0001	Electric	Vertically Integrated	42928	107.98554	7.74	10.57	49.05	4274.618706	2/2/2018	Settled	130	No	Yes	7.49	9.98	49.02	12/2016		4231.16079	Average	10	9.98%	2/2/2018	10.30%	8.31%
North Carolina	Duke Energy Progress LLC	DUK	D-E-2, Sub 1142	Electric	Vertically Integrated	42887	148.932	7.66	9.9	53	3171.039	2/5/2018	Settled	103.938	No	No	7.66	9.9	53	12/2016		3153.765	Year-end	8	9.90%	2/5/2018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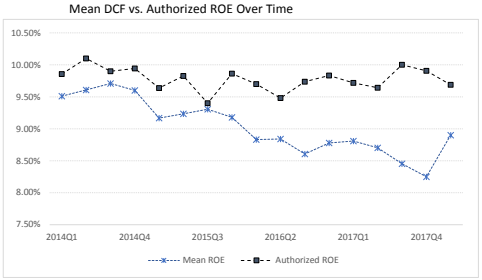

		2014Q1	2014Q2	2014Q3	2014Q4	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2017Q1	2017Q2	2017Q3	2017Q4	2018Q1
	Mean ROE	9.51%	9.61%	9.71%	9.60%	9.17%	9.23%	9.31%	9.18%	8.83%	8.84%	8.61%	8.78%	8.81%	8.70%	8.45%	8.25%	8.90%
Rate Cases	Authorized ROE	9.86%	10.10%	9.90%	9.94%	9.64%	9.83%	9.40%	9.86%	9.70%	9.48%	9.74%	9.83%	9.72%	9.64%	10.00%	9.91%	9.69%

Constant Growth Discounted Cash Flow Model - Q1 2014
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$1.96	$50.06	3.92%	4.03%	6.00%	6.00%	6.00%	6.00%	10.03%	10.03%	10.03%
Alliant Energy Corporation	LNT	$2.04	$52.85	3.86%	3.97%	5.50%	5.40%	6.00%	5.63%	9.36%	9.60%	9.98%
Ameren Corporation	AEE	$1.60	$38.52	4.15%	4.26%	7.50%	5.00%	2.50%	5.00%	6.71%	9.26%	11.81%
American Electric Power Company, Inc.	AEP	$2.00	$48.59	4.12%	4.21%	4.30%	4.23%	4.50%	4.34%	8.43%	8.55%	8.71%
Black Hills Corporation	BKH	$1.56	$55.16	2.83%	2.94%	4.00%	7.00%	13.00%	8.00%	6.88%	10.94%	16.01%
CMS Energy Corporation	CMS	$1.08	$27.71	3.90%	4.02%	6.00%	6.24%	6.50%	6.25%	10.01%	10.27%	10.52%
DTE Energy Company	DTE	$2.62	$69.21	3.79%	3.89%	6.20%	5.21%	5.00%	5.47%	8.88%	9.36%	10.10%
Duke Energy Corporation	DUK	$3.12	$69.70	4.48%	4.56%	3.90%	3.92%	4.00%	3.94%	8.46%	8.50%	8.57%
El Paso Electric Company	EE	$1.06	$35.33	3.00%	3.04%	3.50%	3.70%	1.50%	2.90%	4.52%	5.94%	6.76%
Hawaiian Electric Industries, Inc.	HE	$1.24	$25.56	4.85%	4.96%	6.00%	4.20%	3.50%	4.57%	8.44%	9.53%	11.00%
IDACORP, Inc.	IDA	$1.72	$53.58	3.21%	3.26%	4.00%	4.00%	2.00%	3.33%	5.24%	6.60%	7.27%
NorthWestern Corporation	NWE	$1.60	$45.15	3.54%	3.65%	6.00%	8.00%	4.50%	6.17%	8.12%	9.82%	11.69%
OGE Energy Corp.	OGE	$0.90	$34.96	2.57%	2.64%	6.00%	5.00%	5.50%	5.50%	7.64%	8.14%	8.65%
Otter Tail Corporation	OTTR	$1.21	$29.49	4.10%	4.32%	NA	6.00%	15.00%	10.50%	10.23%	14.82%	19.41%
Pinnacle West Capital Corporation	PNW	$2.27	$53.58	4.24%	4.33%	4.60%	4.13%	4.00%	4.24%	8.32%	8.57%	8.93%
PNM Resources, Inc.	PNM	$0.74	$25.30	2.92%	3.06%	7.60%	8.20%	12.00%	9.27%	10.64%	12.33%	15.10%
Portland General Electric Company	POR	$1.10	$30.78	3.57%	3.70%	6.60%	10.89%	3.50%	7.00%	7.14%	10.70%	14.66%
Southern Company	SO	$2.03	$41.91	4.84%	4.93%	4.10%	3.55%	3.50%	3.72%	8.43%	8.65%	9.04%
WEC Energy Group, Inc.	WEC	$1.56	$43.09	3.62%	3.72%	5.20%	4.86%	6.00%	5.35%	8.57%	9.07%	9.73%
PROXY GROUP MEAN				3.76%	3.87%	5.39%	5.55%	5.71%	5.64%	8.21%	9.51%	10.95%
PROXY GROUP MEDIAN				3.86%	3.97%	5.75%	5.00%	4.50%	5.47%	8.43%	9.36%	10.03%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of March 31, 2014
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model Q2 2014
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$1.96	$50.25	3.90%	4.02%	6.00%	6.00%	6.00%	6.00%	10.02%	10.02%	10.02%
Alliant Energy Corporation	LNT	$2.04	$57.92	3.52%	3.62%	5.50%	4.90%	6.00%	5.47%	8.51%	9.09%	9.63%
Ameren Corporation	AEE	$1.60	$39.87	4.01%	4.11%	7.50%	2.00%	4.50%	4.67%	6.05%	8.77%	11.66%
American Electric Power Company, Inc.	AEP	$2.00	$52.75	3.79%	3.88%	4.80%	4.79%	4.50%	4.70%	8.38%	8.58%	8.68%
Black Hills Corporation	BKH	$1.56	$58.06	2.69%	2.80%	NA	7.00%	9.50%	8.25%	9.78%	11.05%	12.31%
CMS Energy Corporation	CMS	$1.08	$29.76	3.63%	3.75%	6.10%	6.58%	6.50%	6.39%	9.84%	10.14%	10.33%
DTE Energy Company	DTE	$2.76	$76.24	3.62%	3.73%	6.20%	5.85%	6.50%	6.18%	9.58%	9.92%	10.24%
Duke Energy Corporation	DUK	$3.12	$71.93	4.34%	4.43%	4.20%	4.19%	5.00%	4.46%	8.62%	8.90%	9.45%
El Paso Electric Company	EE	$1.12	$37.24	3.01%	3.08%	3.50%	7.00%	3.00%	4.50%	6.05%	7.58%	10.11%
Hawaiian Electric Industries, Inc.	HE	$1.24	$24.35	5.09%	5.21%	6.00%	3.20%	4.00%	4.40%	8.37%	9.61%	11.25%
IDACORP, Inc.	IDA	$1.72	$55.23	3.11%	3.17%	4.00%	4.00%	2.00%	3.33%	5.15%	6.50%	7.18%
NorthWestern Corporation	NWE	$1.60	$48.06	3.33%	3.43%	7.00%	7.00%	3.50%	5.83%	6.89%	9.26%	10.45%
OGE Energy Corp.	OGE	$0.90	$36.62	2.46%	2.53%	5.90%	6.60%	5.50%	6.00%	8.03%	8.53%	9.14%
Otter Tail Corporation	OTTR	$1.21	$29.11	4.16%	4.38%	NA	6.00%	15.50%	10.75%	10.28%	15.13%	19.98%
Pinnacle West Capital Corporation	PNW	$2.27	$55.33	4.10%	4.19%	4.10%	4.28%	4.00%	4.13%	8.19%	8.31%	8.47%
PNM Resources, Inc.	PNM	$0.74	$27.94	2.65%	2.78%	8.50%	8.39%	12.00%	9.63%	11.15%	12.41%	14.81%
Portland General Electric Company	POR	$1.12	$32.97	3.40%	3.53%	8.10%	11.21%	5.00%	8.10%	8.48%	11.64%	14.80%
Southern Company	SO	$2.10	$44.22	4.75%	4.83%	3.50%	3.35%	3.50%	3.45%	8.18%	8.28%	8.33%
WEC Energy Group, Inc.	WEC	$1.56	$46.46	3.36%	3.45%	5.50%	5.24%	5.50%	5.41%	8.69%	8.86%	8.95%
PROXY GROUP MEAN				3.63%	3.73%	5.67%	5.66%	5.89%	5.88%	8.43%	9.61%	10.83%
PROXY GROUP MEDIAN				3.62%	3.73%	5.90%	5.85%	5.00%	5.47%	8.48%	9.09%	10.11%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of June 30, 2014
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Q3 2014
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$1.96	$47.90	4.09%	4.21%	NA	6.00%	6.00%	6.00%	10.21%	10.21%	10.21%
Alliant Energy Corporation	LNT	$2.04	$57.68	3.54%	3.63%	5.10%	4.70%	6.00%	5.27%	8.32%	8.90%	9.64%
Ameren Corporation	AEE	$1.60	$39.10	4.09%	4.24%	8.30%	8.90%	4.50%	7.23%	8.68%	11.47%	13.17%
American Electric Power Company, Inc.	AEP	$2.00	$52.87	3.78%	3.87%	4.80%	4.79%	4.50%	4.70%	8.37%	8.57%	8.67%
Black Hills Corporation	BKH	$1.56	$53.68	2.91%	3.03%	NA	7.00%	9.50%	8.25%	10.01%	11.28%	12.54%
CMS Energy Corporation	CMS	$1.08	$29.85	3.62%	3.74%	6.10%	6.80%	6.50%	6.47%	9.83%	10.20%	10.54%
DTE Energy Company	DTE	$2.76	$76.09	3.63%	3.74%	6.20%	5.87%	6.50%	6.19%	9.60%	9.93%	10.25%
Duke Energy Corporation	DUK	$3.18	$72.96	4.36%	4.46%	4.70%	4.70%	5.00%	4.80%	9.16%	9.26%	9.47%
El Paso Electric Company	EE	$1.12	$37.87	2.96%	3.02%	3.50%	7.00%	3.00%	4.50%	6.00%	7.52%	10.06%
Hawaiian Electric Industries, Inc.	HE	$1.24	$24.82	5.00%	5.10%	4.00%	4.00%	4.00%	4.00%	9.10%	9.10%	9.10%
IDACORP, Inc.	IDA	$1.88	$55.05	3.42%	3.47%	4.00%	4.00%	1.00%	3.00%	4.43%	6.47%	7.48%
NorthWestern Corporation	NWE	$1.60	$48.07	3.33%	3.43%	7.00%	7.00%	3.50%	5.83%	6.89%	9.26%	10.44%
OGE Energy Corp.	OGE	$1.00	$36.81	2.72%	2.80%	6.50%	7.05%	5.50%	6.35%	8.29%	9.15%	9.86%
Otter Tail Corporation	OTTR	$1.21	$28.29	4.28%	4.51%	NA	6.00%	15.50%	10.75%	10.41%	15.26%	20.11%
Pinnacle West Capital Corporation	PNW	$2.27	$55.72	4.07%	4.15%	3.70%	3.75%	4.00%	3.82%	7.85%	7.97%	8.16%
PNM Resources, Inc.	PNM	$0.74	$26.52	2.79%	2.92%	8.50%	8.32%	11.00%	9.27%	11.23%	12.19%	13.94%
Portland General Electric Company	POR	$1.12	$33.19	3.37%	3.49%	7.80%	7.80%	5.00%	6.87%	8.46%	10.36%	11.31%
Southern Company	SO	$2.10	$43.93	4.78%	4.86%	3.50%	3.35%	3.50%	3.45%	8.21%	8.31%	8.36%
WEC Energy Group, Inc.	WEC	$1.56	$44.40	3.51%	3.61%	5.50%	5.33%	5.50%	5.44%	8.94%	9.05%	9.11%
PROXY GROUP MEAN				3.70%	3.80%	5.58%	5.91%	5.79%	5.90%	8.63%	9.71%	10.65%
PROXY GROUP MEDIAN				3.62%	3.74%	5.30%	6.00%	5.00%	5.83%	8.68%	9.26%	10.06%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of September 30, 2014
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Q4 2014
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$1.96	$51.17	3.83%	3.95%	NA	6.00%	6.00%	6.00%	9.95%	9.95%	9.95%
Alliant Energy Corporation	LNT	$2.04	$61.91	3.30%	3.38%	4.90%	4.90%	6.00%	5.27%	8.28%	8.65%	9.39%
Ameren Corporation	AEE	$1.64	$42.51	3.86%	4.00%	8.30%	8.90%	4.50%	7.23%	8.44%	11.23%	12.93%
American Electric Power Company, Inc.	AEP	$2.12	$57.22	3.70%	3.79%	4.90%	5.20%	4.50%	4.87%	8.29%	8.66%	9.00%
Black Hills Corporation	BKH	$1.56	$52.63	2.96%	3.09%	NA	7.00%	9.50%	8.25%	10.07%	11.34%	12.60%
CMS Energy Corporation	CMS	$1.08	$32.67	3.31%	3.41%	6.10%	6.60%	6.50%	6.40%	9.51%	9.81%	10.02%
DTE Energy Company	DTE	$2.76	$81.58	3.38%	3.48%	6.20%	6.17%	5.50%	5.96%	8.98%	9.44%	9.69%
Duke Energy Corporation	DUK	$3.18	$80.63	3.94%	4.04%	4.80%	4.79%	5.00%	4.86%	8.83%	8.90%	9.04%
El Paso Electric Company	EE	$1.12	$37.88	2.96%	3.04%	6.70%	7.00%	3.00%	5.57%	6.00%	8.61%	10.06%
Hawaiian Electric Industries, Inc.	HE	$1.24	$29.12	4.26%	4.34%	4.00%	3.35%	4.00%	3.78%	7.68%	8.12%	8.34%
IDACORP, Inc.	IDA	$1.88	$61.34	3.06%	3.11%	4.00%	4.00%	1.50%	3.17%	4.59%	6.28%	7.13%
NorthWestern Corporation	NWE	$1.60	$52.19	3.07%	3.16%	7.10%	7.05%	3.50%	5.88%	6.62%	9.04%	10.27%
OGE Energy Corp.	OGE	$1.00	$36.11	2.77%	2.86%	6.50%	7.05%	5.50%	6.35%	8.35%	9.21%	9.92%
Otter Tail Corporation	OTTR	$1.21	$29.53	4.10%	4.32%	NA	6.00%	15.50%	10.75%	10.22%	15.07%	19.91%
Pinnacle West Capital Corporation	PNW	$2.38	$62.15	3.83%	3.90%	4.00%	3.60%	4.00%	3.87%	7.50%	7.77%	7.91%
PNM Resources, Inc.	PNM	$0.80	$28.33	2.82%	2.96%	9.10%	9.86%	11.00%	9.99%	12.05%	12.95%	13.98%
Portland General Electric Company	POR	$1.12	$36.19	3.10%	3.20%	8.00%	7.97%	5.00%	6.99%	8.17%	10.19%	11.22%
Southern Company	SO	$2.10	$47.22	4.45%	4.52%	3.60%	3.34%	3.50%	3.48%	7.86%	8.00%	8.13%
WEC Energy Group, Inc.	WEC	$1.69	$49.06	3.45%	3.54%	6.00%	5.44%	5.50%	5.65%	8.98%	9.19%	9.55%
PROXY GROUP MEAN				3.48%	3.58%	5.89%	6.01%	5.76%	6.02%	8.44%	9.60%	10.48%
PROXY GROUP MEDIAN				3.38%	3.48%	6.05%	6.00%	5.00%	5.88%	8.35%	9.19%	9.92%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of December 31, 2014
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Q1 2015
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.02	$54.93	3.68%	3.80%	NA	6.00%	7.00%	6.50%	9.79%	10.30%	10.81%
Alliant Energy Corporation	LNT	$2.20	$65.12	3.38%	3.47%	5.30%	5.40%	6.00%	5.57%	8.77%	9.04%	9.48%
Ameren Corporation	AEE	$1.64	$43.52	3.77%	3.89%	7.30%	6.85%	5.00%	6.38%	8.86%	10.27%	11.21%
American Electric Power Company, Inc.	AEP	$2.12	$59.33	3.57%	3.67%	4.80%	5.21%	5.50%	5.17%	8.46%	8.84%	9.17%
Black Hills Corporation	BKH	$1.62	$50.43	3.21%	3.35%	NA	7.00%	9.50%	8.25%	10.33%	11.60%	12.87%
CMS Energy Corporation	CMS	$1.16	$35.50	3.27%	3.37%	6.20%	6.73%	5.50%	6.14%	8.86%	9.51%	10.11%
DTE Energy Company	DTE	$2.76	$84.36	3.27%	3.36%	5.00%	4.51%	6.00%	5.17%	7.86%	8.53%	9.37%
Duke Energy Corporation	DUK	$3.18	$81.17	3.92%	4.01%	4.70%	4.52%	5.00%	4.74%	8.53%	8.75%	9.02%
El Paso Electric Company	EE	$1.12	$38.56	2.90%	2.98%	6.70%	7.00%	1.50%	5.07%	4.43%	8.04%	10.01%
Hawaiian Electric Industries, Inc.	HE	$1.24	$33.33	3.72%	3.79%	4.00%	3.35%	4.00%	3.78%	7.13%	7.57%	7.79%
IDACORP, Inc.	IDA	$1.88	$64.29	2.92%	2.96%	3.00%	3.00%	1.50%	2.50%	4.45%	5.46%	5.97%
NorthWestern Corporation	NWE	$1.92	$55.12	3.48%	3.61%	7.60%	7.60%	6.50%	7.23%	10.10%	10.84%	11.22%
OGE Energy Corp.	OGE	$1.00	$33.53	2.98%	3.04%	5.00%	4.00%	3.00%	4.00%	6.03%	7.04%	8.06%
Otter Tail Corporation	OTTR	$1.23	$31.85	3.86%	4.02%	NA	6.00%	10.00%	8.00%	9.98%	12.02%	14.06%
Pinnacle West Capital Corporation	PNW	$2.38	$66.74	3.57%	3.64%	4.00%	4.20%	4.00%	4.07%	7.64%	7.71%	7.84%
PNM Resources, Inc.	PNM	$0.80	$29.12	2.75%	2.88%	8.90%	9.86%	11.00%	9.92%	11.77%	12.80%	13.90%
Portland General Electric Company	POR	$1.12	$37.71	2.97%	3.05%	5.90%	5.26%	5.00%	5.39%	8.04%	8.44%	8.96%
Southern Company	SO	$2.10	$47.51	4.42%	4.50%	3.60%	3.30%	4.00%	3.63%	7.79%	8.13%	8.51%
WEC Energy Group, Inc.	WEC	$1.69	$52.30	3.23%	3.33%	6.00%	5.84%	6.00%	5.95%	9.17%	9.27%	9.33%
PROXY GROUP MEAN				3.41%	3.51%	5.50%	5.56%	5.58%	5.66%	8.31%	9.17%	9.88%
PROXY GROUP MEDIAN				3.38%	3.47%	5.15%	5.40%	5.50%	5.39%	8.53%	8.84%	9.37%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of March 31, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Q2 2015
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.02	$49.74	4.06%	4.19%	NA	6.00%	6.50%	6.25%	10.18%	10.44%	10.69%
Alliant Energy Corporation	LNT	$2.20	$60.62	3.63%	3.73%	5.30%	5.45%	6.00%	5.58%	9.03%	9.31%	9.74%
Ameren Corporation	AEE	$1.64	$40.16	4.08%	4.21%	6.80%	5.85%	6.00%	6.22%	10.05%	10.43%	11.02%
American Electric Power Company, Inc.	AEP	$2.12	$55.36	3.83%	3.93%	4.90%	5.08%	5.00%	4.99%	8.82%	8.92%	9.01%
Black Hills Corporation	BKH	$1.62	$47.96	3.38%	3.48%	NA	7.00%	4.50%	5.75%	7.95%	9.23%	10.50%
CMS Energy Corporation	CMS	$1.16	$33.60	3.45%	3.56%	6.20%	6.73%	5.50%	6.14%	9.05%	9.70%	10.30%
DTE Energy Company	DTE	$2.92	$78.59	3.72%	3.81%	5.00%	4.51%	5.00%	4.84%	8.31%	8.64%	8.81%
Duke Energy Corporation	DUK	$3.18	$75.57	4.21%	4.31%	4.70%	4.49%	5.00%	4.73%	8.79%	9.04%	9.31%
El Paso Electric Company	EE	$1.18	$36.44	3.24%	3.33%	6.70%	7.00%	3.50%	5.73%	6.79%	9.06%	10.35%
Hawaiian Electric Industries, Inc.	HE	$1.24	$31.09	3.99%	4.06%	3.80%	3.80%	3.50%	3.70%	7.56%	7.76%	7.86%
IDACORP, Inc.	IDA	$1.88	$59.55	3.16%	3.20%	4.00%	4.00%	1.00%	3.00%	4.17%	6.20%	7.22%
NorthWestern Corporation	NWE	$1.92	$51.68	3.72%	3.82%	5.00%	5.00%	6.50%	5.50%	8.81%	9.32%	10.34%
OGE Energy Corp.	OGE	$1.00	$31.12	3.21%	3.28%	5.00%	4.00%	3.00%	4.00%	6.26%	7.28%	8.29%
Otter Tail Corporation	OTTR	$1.23	$28.71	4.28%	4.45%	NA	6.00%	9.00%	7.50%	10.41%	11.95%	13.48%
Pinnacle West Capital Corporation	PNW	$2.38	$60.29	3.95%	4.04%	4.60%	5.30%	4.00%	4.63%	8.03%	8.67%	9.35%
PNM Resources, Inc.	PNM	$0.80	$26.77	2.99%	3.12%	8.00%	8.56%	9.50%	8.69%	11.11%	11.81%	12.63%
Portland General Electric Company	POR	$1.20	$35.07	3.42%	3.51%	5.20%	4.72%	6.00%	5.31%	8.22%	8.82%	9.52%
Southern Company	SO	$2.17	$43.57	4.98%	5.07%	3.50%	3.32%	4.50%	3.77%	8.38%	8.85%	9.59%
WEC Energy Group, Inc.	WEC	$1.83	$48.01	3.81%	3.93%	6.00%	6.28%	6.00%	6.09%	9.93%	10.02%	10.21%
PROXY GROUP MEAN				3.74%	3.84%	5.29%	5.43%	5.26%	5.39%	8.52%	9.23%	9.91%
PROXY GROUP MEDIAN				3.72%	3.82%	5.00%	5.30%	5.00%	5.50%	8.79%	9.06%	9.74%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of June 30, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Q3 2015
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.02	$48.50	4.17%	4.30%	NA	6.00%	6.50%	6.25%	10.29%	10.55%	10.80%
Alliant Energy Corporation	LNT	$2.20	$58.88	3.74%	3.84%	5.30%	5.75%	6.00%	5.68%	9.14%	9.53%	9.85%
Ameren Corporation	AEE	$1.64	$40.28	4.07%	4.21%	6.80%	6.25%	7.00%	6.68%	10.45%	10.89%	11.21%
American Electric Power Company, Inc.	AEP	$2.12	$55.49	3.82%	3.91%	4.90%	4.63%	5.00%	4.84%	8.54%	8.76%	8.92%
Black Hills Corporation	BKH	$1.62	$41.06	3.95%	4.02%	NA	3.48%	4.50%	3.99%	7.49%	8.01%	8.53%
CMS Energy Corporation	CMS	$1.16	$33.73	3.44%	3.54%	6.20%	6.76%	5.50%	6.15%	9.03%	9.70%	10.32%
DTE Energy Company	DTE	$2.92	$78.58	3.72%	3.81%	5.30%	4.89%	5.00%	5.06%	8.70%	8.87%	9.11%
Duke Energy Corporation	DUK	$3.30	$72.41	4.56%	4.66%	4.70%	4.33%	5.00%	4.68%	8.99%	9.34%	9.67%
El Paso Electric Company	EE	$1.18	$35.86	3.29%	3.38%	6.70%	7.00%	3.50%	5.73%	6.85%	9.12%	10.41%
Hawaiian Electric Industries, Inc.	HE	$1.24	$29.33	4.23%	4.31%	3.80%	3.80%	3.50%	3.70%	7.80%	8.01%	8.11%
IDACORP, Inc.	IDA	$2.04	$60.28	3.38%	3.43%	4.00%	4.00%	1.00%	3.00%	4.40%	6.43%	7.45%
NorthWestern Corporation	NWE	$1.92	$52.12	3.68%	3.79%	5.00%	5.28%	6.50%	5.59%	8.78%	9.38%	10.30%
OGE Energy Corp.	OGE	$1.10	$28.50	3.86%	3.93%	5.00%	3.34%	3.00%	3.78%	6.92%	7.71%	8.96%
Otter Tail Corporation	OTTR	$1.23	$26.41	4.66%	4.83%	NA	6.00%	9.00%	7.50%	10.80%	12.33%	13.87%
Pinnacle West Capital Corporation	PNW	$2.38	$61.11	3.89%	3.99%	5.20%	5.37%	4.00%	4.86%	7.97%	8.85%	9.37%
PNM Resources, Inc.	PNM	$0.80	$26.09	3.07%	3.20%	8.00%	8.56%	9.00%	8.52%	11.19%	11.72%	12.20%
Portland General Electric Company	POR	$1.20	$35.24	3.41%	3.49%	4.30%	4.07%	6.00%	4.79%	7.54%	8.28%	9.51%
Southern Company	SO	$2.17	$43.87	4.95%	5.04%	3.90%	3.58%	4.50%	3.99%	8.61%	9.04%	9.56%
WEC Energy Group, Inc.	WEC	$1.76	$48.64	3.62%	3.74%	6.20%	7.55%	6.00%	6.58%	9.73%	10.32%	11.31%
PROXY GROUP MEAN				3.87%	3.97%	5.33%	5.30%	5.29%	5.34%	8.59%	9.31%	9.97%
PROXY GROUP MEDIAN				3.82%	3.91%	5.10%	5.28%	5.00%	5.06%	8.70%	9.12%	9.67%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of September 30, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Q4 2015
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.02	$50.75	3.98%	4.09%	5.00%	5.00%	6.50%	5.50%	9.08%	9.59%	10.61%
Alliant Energy Corporation	LNT	$2.20	$60.10	3.66%	3.76%	5.40%	5.55%	6.00%	5.65%	9.16%	9.41%	9.77%
Ameren Corporation	AEE	$1.70	$43.37	3.92%	4.05%	6.60%	6.35%	7.00%	6.65%	10.39%	10.70%	11.06%
American Electric Power Company, Inc.	AEP	$2.24	$56.67	3.95%	4.05%	4.80%	4.57%	5.00%	4.79%	8.61%	8.84%	9.05%
Black Hills Corporation	BKH	$1.62	$43.94	3.69%	3.77%	4.20%	3.48%	6.00%	4.56%	7.23%	8.33%	9.80%
CMS Energy Corporation	CMS	$1.16	$35.65	3.25%	3.35%	6.20%	6.72%	5.50%	6.14%	8.84%	9.49%	10.08%
DTE Energy Company	DTE	$2.92	$80.90	3.61%	3.70%	5.50%	5.00%	5.00%	5.17%	8.70%	8.87%	9.21%
Duke Energy Corporation	DUK	$3.30	$70.31	4.69%	4.79%	4.10%	3.27%	5.00%	4.12%	8.04%	8.91%	9.81%
El Paso Electric Company	EE	$1.18	$38.19	3.09%	3.18%	6.70%	7.00%	3.50%	5.73%	6.64%	8.91%	10.20%
Hawaiian Electric Industries, Inc.	HE	$1.24	$28.83	4.30%	4.37%	3.20%	3.20%	3.50%	3.30%	7.57%	7.67%	7.88%
IDACORP, Inc.	IDA	$2.04	$67.36	3.03%	3.07%	4.00%	4.00%	1.00%	3.00%	4.04%	6.07%	7.09%
NorthWestern Corporation	NWE	$1.92	$54.41	3.53%	3.64%	5.00%	6.81%	6.50%	6.10%	8.62%	9.74%	10.46%
OGE Energy Corp.	OGE	$1.10	$26.84	4.10%	4.16%	4.60%	2.17%	3.00%	3.26%	6.31%	7.42%	8.79%
Otter Tail Corporation	OTTR	$1.23	$26.83	4.58%	4.76%	NA	6.00%	9.00%	7.50%	10.72%	12.26%	13.79%
Pinnacle West Capital Corporation	PNW	$2.50	$63.64	3.93%	4.02%	4.80%	4.95%	4.00%	4.58%	8.01%	8.60%	8.98%
PNM Resources, Inc.	PNM	$0.88	$28.66	3.07%	3.20%	7.70%	9.30%	9.00%	8.67%	10.89%	11.87%	12.51%
Portland General Electric Company	POR	$1.20	$36.88	3.25%	3.33%	4.40%	4.11%	6.00%	4.84%	7.43%	8.17%	9.35%
Southern Company	SO	$2.17	$45.33	4.79%	4.88%	3.90%	3.73%	4.50%	4.04%	8.61%	8.93%	9.39%
WEC Energy Group, Inc.	WEC	$1.98	$51.04	3.88%	4.01%	6.20%	7.55%	6.00%	6.58%	10.00%	10.59%	11.58%
PROXY GROUP MEAN				3.81%	3.91%	5.13%	5.20%	5.37%	5.27%	8.36%	9.18%	9.97%
PROXY GROUP MEDIAN				3.88%	4.01%	4.90%	5.00%	5.50%	5.17%	8.61%	8.91%	9.80%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of December 31, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Q1 2016
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.08	$53.31	3.90%	4.01%	6.00%	6.00%	4.00%	5.33%	7.98%	9.34%	10.02%
Alliant Energy Corporation	LNT	$2.35	$67.42	3.49%	3.59%	6.10%	6.65%	6.00%	6.25%	9.59%	9.84%	10.25%
Ameren Corporation	AEE	$1.70	$46.14	3.68%	3.79%	6.10%	5.60%	5.00%	5.57%	8.78%	9.35%	9.90%
American Electric Power Company, Inc.	AEP	$2.24	$61.84	3.62%	3.71%	5.10%	4.83%	4.50%	4.81%	8.20%	8.52%	8.81%
Black Hills Corporation	BKH	$1.68	$53.38	3.15%	3.21%	4.60%	5.00%	3.00%	4.20%	6.19%	7.41%	8.23%
CMS Energy Corporation	CMS	$1.24	$39.17	3.17%	3.27%	6.40%	7.24%	6.00%	6.55%	9.26%	9.82%	10.52%
DTE Energy Company	DTE	$2.92	$84.89	3.44%	3.52%	5.40%	4.90%	4.50%	4.93%	8.02%	8.46%	8.93%
Duke Energy Corporation	DUK	$3.30	$75.68	4.36%	4.46%	4.30%	3.79%	5.00%	4.36%	8.23%	8.82%	9.47%
El Paso Electric Company	EE	$1.18	$41.12	2.87%	2.95%	6.70%	7.00%	3.50%	5.73%	6.42%	8.69%	9.97%
Hawaiian Electric Industries, Inc.	HE	$1.24	$29.95	4.14%	4.23%	7.00%	3.20%	3.50%	4.57%	7.41%	8.80%	11.28%
IDACORP, Inc.	IDA	$2.04	$70.62	2.89%	2.93%	4.00%	4.00%	1.00%	3.00%	3.90%	5.93%	6.95%
NorthWestern Corporation	NWE	$2.00	$57.66	3.47%	3.56%	5.00%	5.00%	6.50%	5.50%	8.56%	9.06%	10.08%
OGE Energy Corp.	OGE	$1.10	$26.35	4.17%	4.24%	4.80%	1.75%	2.50%	3.02%	5.96%	7.25%	9.07%
Otter Tail Corporation	OTTR	$1.25	$27.45	4.55%	4.69%	NA	6.00%	6.00%	6.00%	10.69%	10.69%	10.69%
Pinnacle West Capital Corporation	PNW	$2.50	$68.37	3.66%	3.73%	4.00%	3.60%	4.00%	3.87%	7.32%	7.59%	7.73%
PNM Resources, Inc.	PNM	$0.88	$31.98	2.75%	2.87%	7.60%	8.76%	9.00%	8.45%	10.46%	11.32%	11.88%
Portland General Electric Company	POR	$1.20	$38.29	3.13%	3.23%	5.80%	5.73%	6.00%	5.84%	8.95%	9.07%	9.23%
Southern Company	SO	$2.17	$48.72	4.45%	4.53%	4.10%	3.28%	2.50%	3.29%	7.01%	7.82%	8.65%
WEC Energy Group, Inc.	WEC	$1.98	$55.99	3.54%	3.65%	6.30%	6.77%	6.00%	6.36%	9.64%	10.01%	10.43%
PROXY GROUP MEAN				3.60%	3.69%	5.52%	5.22%	4.66%	5.14%	8.03%	8.83%	9.58%
PROXY GROUP MEDIAN				3.54%	3.65%	5.60%	5.00%	4.50%	5.33%	8.20%	8.82%	9.90%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of March 31, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Q2 2016
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.08	$57.69	3.61%	3.69%	5.50%	5.00%	4.00%	4.83%	7.68%	8.53%	9.20%
Alliant Energy Corporation	LNT	$1.18	$37.10	3.17%	3.27%	6.10%	6.60%	6.00%	6.23%	9.26%	9.50%	9.87%
Ameren Corporation	AEE	$1.70	$49.16	3.46%	3.56%	6.10%	5.20%	6.00%	5.77%	8.75%	9.32%	9.66%
American Electric Power Company, Inc.	AEP	$2.24	$65.44	3.42%	3.50%	4.90%	4.10%	4.00%	4.33%	7.49%	7.83%	8.41%
Black Hills Corporation	BKH	$1.68	$60.28	2.79%	2.88%	6.50%	6.50%	6.50%	6.50%	9.38%	9.38%	9.38%
CMS Energy Corporation	CMS	$1.24	$42.01	2.95%	3.05%	6.40%	7.24%	6.00%	6.55%	9.04%	9.59%	10.30%
DTE Energy Company	DTE	$3.08	$90.87	3.39%	3.48%	5.80%	5.35%	5.00%	5.38%	8.47%	8.86%	9.29%
Duke Energy Corporation	DUK	$3.30	$79.92	4.13%	4.22%	4.80%	4.62%	4.00%	4.47%	8.21%	8.69%	9.03%
El Paso Electric Company	EE	$1.24	$45.19	2.74%	2.82%	6.70%	7.00%	2.50%	5.40%	5.28%	8.22%	9.84%
Hawaiian Electric Industries, Inc.	HE	$1.24	$32.95	3.76%	3.86%	7.00%	4.00%	4.00%	5.00%	7.84%	8.86%	10.89%
IDACORP, Inc.	IDA	$2.04	$73.73	2.77%	2.82%	4.00%	4.00%	3.00%	3.67%	5.81%	6.48%	6.82%
NorthWestern Corporation	NWE	$2.00	$59.21	3.38%	3.47%	5.00%	5.00%	6.50%	5.50%	8.46%	8.97%	9.99%
OGE Energy Corp.	OGE	$1.10	$29.95	3.67%	3.75%	5.20%	4.30%	3.00%	4.17%	6.73%	7.92%	8.97%
Otter Tail Corporation	OTTR	$1.25	$30.03	4.16%	4.29%	NA	6.00%	6.00%	6.00%	10.29%	10.29%	10.29%
Pinnacle West Capital Corporation	PNW	$2.50	$74.56	3.35%	3.42%	4.00%	3.73%	4.00%	3.91%	7.15%	7.33%	7.42%
PNM Resources, Inc.	PNM	$0.88	$32.87	2.68%	2.79%	7.60%	8.76%	9.00%	8.45%	10.38%	11.24%	11.80%
Portland General Electric Company	POR	$1.28	$40.80	3.14%	3.23%	6.40%	6.57%	5.50%	6.16%	8.72%	9.39%	9.81%
Southern Company	SO	$2.24	$50.29	4.45%	4.53%	4.10%	3.25%	2.50%	3.28%	7.01%	7.81%	8.65%
WEC Energy Group, Inc.	WEC	$1.98	$60.14	3.29%	3.40%	6.30%	6.77%	6.00%	6.36%	9.39%	9.75%	10.17%
PROXY GROUP MEAN				3.38%	3.47%	5.69%	5.47%	4.92%	5.37%	8.18%	8.84%	9.46%
PROXY GROUP MEDIAN				3.38%	3.47%	5.95%	5.20%	5.00%	5.40%	8.46%	8.86%	9.66%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of June 30, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Q3 2016
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.08	$61.74	3.37%	3.45%	5.50%	5.00%	4.00%	4.83%	7.44%	8.28%	8.96%
Alliant Energy Corporation	LNT	$1.18	$39.24	2.99%	3.09%	6.10%	6.60%	6.00%	6.23%	9.08%	9.32%	9.69%
Ameren Corporation	AEE	$1.70	$51.03	3.33%	3.43%	6.10%	5.20%	6.00%	5.77%	8.62%	9.19%	9.53%
American Electric Power Company, Inc.	AEP	$2.24	$67.25	3.33%	3.39%	5.20%	2.31%	4.00%	3.84%	5.68%	7.23%	8.62%
Black Hills Corporation	BKH	$1.68	$60.92	2.76%	2.85%	5.80%	6.70%	7.50%	6.67%	8.64%	9.52%	10.36%
CMS Energy Corporation	CMS	$1.24	$43.66	2.84%	2.93%	6.60%	7.27%	6.00%	6.62%	8.93%	9.56%	10.21%
DTE Energy Company	DTE	$3.08	$95.75	3.22%	3.31%	5.80%	5.51%	6.00%	5.77%	8.82%	9.08%	9.31%
Duke Energy Corporation	DUK	$3.42	$82.82	4.13%	4.22%	4.80%	4.35%	4.00%	4.38%	8.21%	8.60%	9.03%
El Paso Electric Company	EE	$1.24	$46.66	2.66%	2.72%	4.40%	7.00%	2.50%	4.63%	5.19%	7.35%	9.75%
Hawaiian Electric Industries, Inc.	HE	$1.24	$30.73	4.04%	4.12%	4.00%	4.00%	4.00%	4.00%	8.12%	8.12%	8.12%
IDACORP, Inc.	IDA	$2.20	$78.90	2.79%	2.84%	4.00%	4.00%	3.00%	3.67%	5.83%	6.51%	6.84%
NorthWestern Corporation	NWE	$2.00	$59.65	3.35%	3.45%	5.00%	5.00%	6.50%	5.50%	8.44%	8.95%	9.96%
OGE Energy Corp.	OGE	$1.21	$31.66	3.82%	3.90%	5.20%	4.30%	3.00%	4.17%	6.88%	8.07%	9.12%
Otter Tail Corporation	OTTR	$1.25	$34.57	3.62%	3.72%	NA	6.00%	6.00%	6.00%	9.72%	9.72%	9.72%
Pinnacle West Capital Corporation	PNW	$2.50	$77.86	3.21%	3.27%	4.10%	3.85%	4.00%	3.98%	7.12%	7.26%	7.38%
PNM Resources, Inc.	PNM	$0.88	$33.44	2.63%	2.73%	7.00%	6.77%	9.00%	7.59%	9.49%	10.32%	11.75%
Portland General Electric Company	POR	$1.28	$43.31	2.96%	3.04%	6.00%	5.90%	5.50%	5.80%	8.54%	8.84%	9.04%
Southern Company	SO	$2.24	$52.66	4.25%	4.33%	3.90%	3.16%	4.00%	3.69%	7.48%	8.02%	8.34%
WEC Energy Group, Inc.	WEC	$1.98	$62.43	3.17%	3.27%	6.20%	6.72%	6.00%	6.31%	9.27%	9.58%	10.00%
PROXY GROUP MEAN				3.29%	3.37%	5.32%	5.24%	5.11%	5.23%	7.97%	8.61%	9.25%
PROXY GROUP MEDIAN				3.22%	3.31%	5.35%	5.20%	5.50%	5.50%	8.44%	8.84%	9.31%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of September 30, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Q4 2016
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.08	$61.10	3.40%	3.49%	5.50%	5.00%	4.00%	4.83%	7.47%	8.32%	9.00%
Alliant Energy Corporation	LNT	$1.18	$36.91	3.18%	3.28%	5.50%	6.00%	6.00%	5.83%	8.77%	9.11%	9.28%
Ameren Corporation	AEE	$1.76	$49.58	3.55%	3.66%	6.50%	5.65%	6.00%	6.05%	9.30%	9.71%	10.17%
American Electric Power Company, Inc.	AEP	$2.36	$61.67	3.83%	3.90%	5.40%	1.90%	5.00%	4.10%	5.76%	8.00%	9.33%
Black Hills Corporation	BKH	$1.68	$59.69	2.81%	2.91%	6.20%	7.40%	7.50%	7.03%	9.10%	9.95%	10.42%
CMS Energy Corporation	CMS	$1.24	$40.88	3.03%	3.13%	6.00%	7.27%	6.00%	6.42%	9.12%	9.55%	10.41%
DTE Energy Company	DTE	$3.30	$94.46	3.49%	3.60%	5.80%	5.63%	6.00%	5.81%	9.22%	9.41%	9.60%
Duke Energy Corporation	DUK	$3.42	$76.59	4.47%	4.54%	5.00%	1.70%	4.00%	3.57%	6.20%	8.11%	9.58%
El Paso Electric Company	EE	$1.24	$45.35	2.73%	2.80%	4.40%	7.00%	4.00%	5.13%	6.79%	7.94%	9.83%
Hawaiian Electric Industries, Inc.	HE	$1.24	$30.49	4.07%	4.14%	4.00%	2.75%	4.00%	3.58%	6.87%	7.72%	8.15%
IDACORP, Inc.	IDA	$2.20	$77.08	2.85%	2.91%	4.30%	4.10%	3.00%	3.80%	5.90%	6.71%	7.22%
NorthWestern Corporation	NWE	$2.00	$56.24	3.56%	3.65%	5.00%	4.50%	6.50%	5.33%	8.14%	8.98%	10.17%
OGE Energy Corp.	OGE	$1.21	$31.57	3.83%	3.91%	5.30%	4.00%	3.00%	4.10%	6.89%	8.01%	9.23%
Otter Tail Corporation	OTTR	$1.25	$37.18	3.36%	3.46%	NA	6.00%	6.00%	6.00%	9.46%	9.46%	9.46%
Pinnacle West Capital Corporation	PNW	$2.62	$74.98	3.49%	3.57%	4.90%	4.73%	4.00%	4.54%	7.56%	8.12%	8.48%
PNM Resources, Inc.	PNM	$0.97	$32.44	2.99%	3.10%	5.30%	6.85%	9.00%	7.05%	8.37%	10.15%	12.12%
Portland General Electric Company	POR	$1.28	$42.19	3.03%	3.13%	6.20%	6.67%	5.50%	6.12%	8.62%	9.25%	9.81%
Southern Company	SO	$2.24	$49.13	4.56%	4.65%	4.10%	3.30%	4.00%	3.80%	7.93%	8.45%	8.75%
WEC Energy Group, Inc.	WEC	$1.98	$57.36	3.45%	3.56%	6.00%	6.92%	6.00%	6.31%	9.56%	9.87%	10.49%
PROXY GROUP MEAN				3.46%	3.55%	5.30%	5.12%	5.24%	5.23%	7.95%	8.78%	9.55%
PROXY GROUP MEDIAN				3.45%	3.56%	5.35%	5.63%	5.50%	5.33%	8.14%	8.98%	9.58%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of December 30, 2016
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Q1 2017
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.14	$65.51	3.27%	3.35%	6.10%	5.00%	5.00%	5.37%	8.35%	8.72%	9.47%
Alliant Energy Corporation	LNT	$1.26	$38.37	3.28%	3.38%	5.50%	6.35%	6.00%	5.95%	8.87%	9.33%	9.74%
Ameren Corporation	AEE	$1.76	$53.52	3.29%	3.39%	6.50%	5.85%	6.00%	6.12%	9.23%	9.51%	9.90%
American Electric Power Company, Inc.	AEP	$2.36	$64.77	3.64%	3.71%	5.60%	1.86%	4.00%	3.82%	5.54%	7.53%	9.35%
Black Hills Corporation	BKH	$1.78	$63.26	2.81%	2.93%	6.10%	10.38%	7.50%	7.99%	9.00%	10.92%	13.34%
CMS Energy Corporation	CMS	$1.33	$43.32	3.07%	3.17%	6.00%	7.60%	6.50%	6.70%	9.16%	9.87%	10.79%
DTE Energy Company	DTE	$3.30	$99.52	3.32%	3.40%	6.00%	5.05%	5.00%	5.35%	8.40%	8.75%	9.42%
Duke Energy Corporation	DUK	$3.42	$79.49	4.30%	4.39%	5.00%	2.69%	5.00%	4.23%	7.05%	8.62%	9.41%
El Paso Electric Company	EE	$1.24	$47.38	2.62%	2.69%	5.50%	6.50%	4.00%	5.33%	6.67%	8.02%	9.20%
Hawaiian Electric Industries, Inc.	HE	$1.24	$33.18	3.74%	3.80%	4.00%	2.70%	4.00%	3.57%	6.49%	7.37%	7.81%
IDACORP, Inc.	IDA	$2.20	$80.60	2.73%	2.78%	4.00%	4.00%	3.00%	3.67%	5.77%	6.45%	6.78%
NorthWestern Corporation	NWE	$2.10	$57.44	3.66%	3.75%	4.30%	3.94%	6.50%	4.91%	7.67%	8.66%	10.27%
OGE Energy Corp.	OGE	$1.21	$34.83	3.47%	3.57%	5.30%	6.10%	5.50%	5.63%	8.87%	9.20%	9.68%
Otter Tail Corporation	OTTR	$1.28	$37.88	3.38%	3.47%	NA	5.20%	5.00%	5.10%	8.46%	8.57%	8.67%
Pinnacle West Capital Corporation	PNW	$2.62	$79.93	3.28%	3.36%	5.60%	6.25%	4.00%	5.28%	7.34%	8.65%	9.63%
PNM Resources, Inc.	PNM	$0.97	$35.37	2.74%	2.85%	6.50%	7.55%	9.00%	7.68%	9.33%	10.53%	11.87%
Portland General Electric Company	POR	$1.28	$44.01	2.91%	2.98%	5.40%	5.63%	4.00%	5.01%	6.97%	7.99%	8.62%
Southern Company	SO	$2.24	$49.42	4.53%	4.63%	4.30%	3.84%	4.50%	4.21%	8.46%	8.84%	9.13%
WEC Energy Group, Inc.	WEC	$2.08	$58.94	3.53%	3.64%	6.00%	6.53%	6.00%	6.18%	9.63%	9.81%	10.17%
PROXY GROUP MEAN				3.35%	3.43%	5.43%	5.42%	5.29%	5.37%	7.96%	8.81%	9.64%
PROXY GROUP MEDIAN				3.29%	3.39%	5.55%	5.63%	5.00%	5.33%	8.40%	8.72%	9.47%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of March 31, 2017
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Q2 2017
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.14	$70.99	3.01%	3.10%	6.10%	5.00%	5.00%	5.37%	8.09%	8.46%	9.21%
Alliant Energy Corporation	LNT	$1.26	$40.47	3.11%	3.21%	5.50%	6.45%	6.00%	5.98%	8.70%	9.19%	9.66%
Ameren Corporation	AEE	$1.76	$55.52	3.17%	3.27%	6.50%	6.05%	6.00%	6.18%	9.26%	9.45%	9.77%
American Electric Power Company, Inc.	AEP	$2.36	$69.47	3.40%	3.47%	5.60%	2.39%	4.00%	4.00%	5.83%	7.46%	9.09%
Black Hills Corporation	BKH	$1.78	$68.81	2.59%	2.69%	5.00%	12.00%	7.50%	8.17%	7.65%	10.86%	14.74%
CMS Energy Corporation	CMS	$1.33	$46.23	2.88%	2.97%	6.00%	7.52%	6.50%	6.67%	8.96%	9.65%	10.50%
DTE Energy Company	DTE	$3.30	$106.45	3.10%	3.19%	5.90%	4.87%	6.00%	5.59%	8.05%	8.78%	9.19%
Duke Energy Corporation	DUK	$3.42	$84.06	4.07%	4.15%	5.00%	2.56%	4.50%	4.02%	6.68%	8.17%	9.17%
El Paso Electric Company	EE	$1.34	$52.28	2.56%	2.65%	7.90%	6.50%	5.00%	6.47%	7.63%	9.11%	10.56%
Hawaiian Electric Industries, Inc.	HE	$1.24	$33.26	3.73%	3.78%	4.00%	2.70%	1.50%	2.73%	5.26%	6.51%	7.80%
IDACORP, Inc.	IDA	$2.20	$85.77	2.57%	2.61%	4.00%	4.00%	3.50%	3.83%	6.11%	6.45%	6.62%
NorthWestern Corporation	NWE	$2.10	$61.02	3.44%	3.51%	3.30%	3.37%	4.50%	3.72%	6.80%	7.23%	8.02%
OGE Energy Corp.	OGE	$1.21	$34.98	3.46%	3.56%	5.30%	6.30%	5.50%	5.70%	8.85%	9.26%	9.87%
Otter Tail Corporation	OTTR	$1.28	$39.31	3.26%	3.35%	NA	5.20%	6.50%	5.85%	8.54%	9.20%	9.86%
Pinnacle West Capital Corporation	PNW	$2.62	$86.14	3.04%	3.13%	5.10%	6.26%	5.50%	5.62%	8.22%	8.75%	9.40%
PNM Resources, Inc.	PNM	$0.97	$38.05	2.55%	2.65%	6.50%	7.35%	9.00%	7.62%	9.13%	10.26%	11.66%
Portland General Electric Company	POR	$1.36	$46.10	2.95%	3.03%	5.30%	5.55%	6.00%	5.62%	8.33%	8.65%	9.04%
Southern Company	SO	$2.32	$50.14	4.63%	4.72%	5.00%	3.93%	3.50%	4.14%	8.21%	8.87%	9.74%
WEC Energy Group, Inc.	WEC	$2.08	$61.77	3.37%	3.46%	5.50%	5.28%	6.00%	5.59%	8.74%	9.05%	9.47%
PROXY GROUP MEAN				3.20%	3.29%	5.42%	5.44%	5.37%	5.41%	7.84%	8.70%	9.65%
PROXY GROUP MEDIAN				3.11%	3.21%	5.40%	5.28%	5.50%	5.62%	8.21%	8.87%	9.47%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of June 30, 2017
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Q3 2017
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.14	$74.86	2.86%	2.94%	6.10%	5.00%	6.00%	5.70%	7.93%	8.64%	9.05%
Alliant Energy Corporation	LNT	$1.26	$41.60	3.03%	3.12%	5.50%	6.90%	6.00%	6.13%	8.61%	9.26%	10.03%
Ameren Corporation	AEE	$1.76	$57.80	3.05%	3.14%	6.50%	6.10%	6.00%	6.20%	9.14%	9.34%	9.64%
American Electric Power Company, Inc.	AEP	$2.36	$71.24	3.31%	3.38%	5.40%	2.87%	4.00%	4.09%	6.23%	7.47%	8.80%
Black Hills Corporation	BKH	$1.78	$69.42	2.56%	2.65%	5.00%	7.65%	7.50%	6.72%	7.63%	9.37%	10.31%
CMS Energy Corporation	CMS	$1.33	$47.19	2.82%	2.91%	6.00%	7.44%	6.50%	6.65%	8.90%	9.56%	10.36%
DTE Energy Company	DTE	$3.30	$108.88	3.03%	3.11%	5.90%	4.59%	6.00%	5.50%	7.69%	8.61%	9.12%
Duke Energy Corporation	DUK	$3.56	$85.62	4.16%	4.24%	4.00%	2.65%	4.50%	3.72%	6.86%	7.95%	8.75%
El Paso Electric Company	EE	$1.34	$53.63	2.50%	2.58%	7.20%	6.50%	5.00%	6.23%	7.56%	8.81%	9.79%
Hawaiian Electric Industries, Inc.	HE	$1.24	$33.08	3.75%	3.79%	4.00%	1.40%	1.50%	2.30%	5.17%	6.09%	7.82%
IDACORP, Inc.	IDA	$2.36	$87.48	2.70%	2.75%	4.50%	3.80%	3.50%	3.93%	6.24%	6.68%	7.26%
NorthWestern Corporation	NWE	$2.10	$59.65	3.52%	3.57%	1.60%	3.05%	4.50%	3.05%	5.15%	6.62%	8.10%
OGE Energy Corp.	OGE	$1.33	$35.66	3.73%	3.84%	5.30%	6.30%	6.00%	5.87%	9.13%	9.71%	10.15%
Otter Tail Corporation	OTTR	$1.28	$41.37	3.09%	3.18%	NA	5.20%	6.50%	5.85%	8.37%	9.03%	9.69%
Pinnacle West Capital Corporation	PNW	$2.62	$87.63	2.99%	3.07%	5.20%	6.04%	5.50%	5.58%	8.27%	8.65%	9.12%
PNM Resources, Inc.	PNM	$0.97	$40.66	2.39%	2.47%	4.70%	7.35%	9.00%	7.02%	7.14%	9.49%	11.49%
Portland General Electric Company	POR	$1.36	$46.05	2.95%	3.02%	3.50%	4.90%	6.00%	4.80%	6.50%	7.82%	9.04%
Southern Company	SO	$2.32	$48.48	4.79%	4.87%	4.30%	3.22%	3.50%	3.67%	8.08%	8.55%	9.19%
WEC Energy Group, Inc.	WEC	$2.08	$63.80	3.26%	3.35%	5.30%	5.61%	6.00%	5.64%	8.65%	8.99%	9.36%
PROXY GROUP MEAN				3.18%	3.26%	5.00%	5.08%	5.45%	5.19%	7.54%	8.45%	9.32%
PROXY GROUP MEDIAN				3.03%	3.12%	5.25%	5.20%	6.00%	5.64%	7.69%	8.65%	9.19%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of September 29, 2017
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Q4 2017
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.14	$77.78	2.75%	2.83%	7.20%	5.00%	5.00%	5.73%	7.82%	8.56%	10.05%
Alliant Energy Corporation	LNT	$1.26	$43.59	2.89%	2.98%	6.40%	7.05%	6.00%	6.48%	8.98%	9.47%	10.04%
Ameren Corporation	AEE	$1.83	$61.45	2.98%	3.08%	7.00%	7.00%	6.00%	6.67%	9.07%	9.74%	10.08%
American Electric Power Company, Inc.	AEP	$2.48	$74.72	3.32%	3.38%	4.80%	2.77%	4.00%	3.86%	6.14%	7.24%	8.20%
Black Hills Corporation	BKH	$1.90	$61.94	3.07%	3.15%	4.90%	4.26%	7.50%	5.55%	7.39%	8.71%	10.68%
CMS Energy Corporation	CMS	$1.33	$48.43	2.75%	2.84%	6.50%	7.44%	6.50%	6.81%	9.34%	9.65%	10.29%
DTE Energy Company	DTE	$3.53	$111.66	3.16%	3.25%	6.00%	4.91%	6.00%	5.64%	8.15%	8.89%	9.26%
Duke Energy Corporation	DUK	$3.56	$87.35	4.08%	4.16%	4.00%	3.23%	4.50%	3.91%	7.37%	8.07%	8.67%
El Paso Electric Company	EE	$1.34	$57.98	2.31%	2.37%	5.20%	5.30%	5.00%	5.17%	7.37%	7.54%	7.67%
Hawaiian Electric Industries, Inc.	HE	$1.24	$36.20	3.43%	3.48%	4.20%	4.50%	1.50%	3.40%	4.95%	6.88%	8.00%
IDACORP, Inc.	IDA	$2.36	$93.46	2.53%	2.58%	5.00%	4.00%	3.50%	4.17%	6.07%	6.74%	7.59%
NorthWestern Corporation	NWE	$2.10	$60.26	3.48%	3.53%	1.50%	2.25%	4.50%	2.75%	5.01%	6.28%	8.06%
OGE Energy Corp.	OGE	$1.33	$35.32	3.77%	3.85%	4.30%	3.90%	6.00%	4.73%	7.74%	8.59%	9.88%
Otter Tail Corporation	OTTR	$1.28	$45.84	2.79%	2.88%	NA	5.20%	7.00%	6.10%	8.07%	8.98%	9.89%
Pinnacle West Capital Corporation	PNW	$2.78	$88.29	3.15%	3.22%	3.20%	5.46%	5.50%	4.72%	6.40%	7.94%	8.74%
PNM Resources, Inc.	PNM	$1.06	$42.90	2.47%	2.55%	5.50%	6.05%	7.50%	6.35%	8.04%	8.90%	10.06%
Portland General Electric Company	POR	$1.36	$47.34	2.87%	2.94%	3.80%	4.00%	6.00%	4.60%	6.73%	7.54%	8.96%
Southern Company	SO	$2.32	$50.95	4.55%	4.63%	4.50%	2.33%	3.50%	3.44%	6.94%	8.07%	9.16%
WEC Energy Group, Inc.	WEC	$2.21	$67.10	3.29%	3.39%	5.40%	5.27%	6.00%	5.56%	8.65%	8.94%	9.39%
PROXY GROUP MEAN				3.14%	3.22%	4.97%	4.73%	5.34%	5.03%	7.38%	8.25%	9.19%
PROXY GROUP MEDIAN				3.07%	3.15%	4.95%	4.91%	6.00%	5.17%	7.39%	8.56%	9.26%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of December 29, 2017
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model - Q1 2018
3 Month Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.24	$70.62	3.17%	3.26%	6.60%	6.00%	4.50%	5.70%	7.74%	8.96%	9.88%
Alliant Energy Corporation	LNT	$1.34	$39.45	3.40%	3.49%	5.30%	5.45%	6.50%	5.75%	8.79%	9.24%	10.01%
Ameren Corporation	AEE	$1.83	$55.36	3.31%	3.42%	6.90%	6.37%	7.50%	6.92%	9.78%	10.34%	10.93%
American Electric Power Company, Inc.	AEP	$2.48	$67.33	3.68%	3.78%	5.40%	5.63%	4.50%	5.18%	8.27%	8.96%	9.42%
Black Hills Corporation	BKH	$1.90	$53.50	3.55%	3.65%	4.60%	4.07%	7.50%	5.39%	7.69%	9.04%	11.18%
CMS Energy Corporation	CMS	$1.43	$43.87	3.26%	3.38%	6.30%	7.04%	8.50%	7.28%	9.66%	10.66%	11.90%
DTE Energy Company	DTE	$3.53	$103.03	3.43%	3.53%	6.00%	5.58%	6.50%	6.03%	9.10%	9.56%	10.04%
Duke Energy Corporation	DUK	$3.56	$77.30	4.61%	4.70%	3.70%	4.24%	4.50%	4.15%	8.39%	8.85%	9.21%
El Paso Electric Company	EE	$1.34	$50.60	2.65%	2.72%	5.10%	5.20%	5.00%	5.10%	7.71%	7.82%	7.92%
Hawaiian Electric Industries, Inc.	HE	$1.24	$33.79	3.67%	3.77%	6.70%	8.50%	1.50%	5.57%	5.20%	9.34%	12.33%
IDACORP, Inc.	IDA	$2.36	$84.39	2.80%	2.85%	4.10%	3.10%	3.50%	3.57%	5.94%	6.41%	6.95%
NorthWestern Corporation	NWE	$2.20	$52.90	4.16%	4.23%	2.40%	3.12%	4.50%	3.34%	6.61%	7.57%	8.75%
OGE Energy Corp.	OGE	$1.33	$31.58	4.21%	4.31%	6.00%	5.80%	2.50%	4.77%	6.76%	9.08%	10.34%
Otter Tail Corporation	OTTR	$1.34	$41.84	3.20%	3.33%	NA	9.00%	7.00%	8.00%	10.31%	11.33%	12.35%
Pinnacle West Capital Corporation	PNW	$2.78	$78.45	3.54%	3.62%	3.00%	3.63%	5.50%	4.04%	6.60%	7.66%	9.14%
PNM Resources, Inc.	PNM	$1.06	$36.63	2.89%	2.98%	5.40%	5.80%	7.50%	6.23%	8.37%	9.22%	10.50%
Portland General Electric Company	POR	$1.36	$41.06	3.31%	3.38%	2.90%	3.50%	6.00%	4.13%	6.26%	7.51%	9.41%
Southern Company	SO	$2.32	$44.39	5.23%	5.32%	4.50%	2.70%	4.00%	3.73%	8.00%	9.06%	9.84%
WEC Energy Group, Inc.	WEC	$2.21	$62.05	3.56%	3.65%	4.20%	4.34%	6.00%	4.85%	7.84%	8.49%	9.67%
PROXY GROUP MEAN				3.56%	3.65%	4.95%	5.21%	5.42%	5.25%	7.84%	8.90%	9.99%
PROXY GROUP MEDIAN				3.43%	3.53%	5.20%	5.45%	5.50%	5.18%	7.84%	9.04%	9.88%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 3-month average as of March 30, 2018
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Rate Case History (Past Rate Cases) - Regulatory Research Associates

List None
Company List All
States All
Years 2018, 2017, 2016, 2015, 2014
Service Type Electric

Q1 2014

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
North Dakota	Northern States Power Co. - MN	XEL	C-PU-12-813	Electric	Vertically Integrated	2/26/2014	9.75
New Mexico	Southwestern Public Service Co	XEL	C-12-00350-UT	Electric	Vertically Integrated	3/26/2014	9.96
							9.86%

Q2 2014

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
Texas	Entergy Texas Inc.	ETR	D-41791	Electric	Vertically Integrated	5/16/2014	9.80
Wisconsin	Wisconsin Power and Light Co	LNT	D-6680-UR-119 (Elec)	Electric	Vertically Integrated	6/6/2014	10.40
							10.10%

Q3 2014

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
Louisiana	Entergy Louisiana LLC	ETR	D-UD-13-01	Electric	Vertically Integrated	7/10/2014	9.95
Wyoming	Cheyenne Light Fuel Power Co.	BKH	D-20003-132-ER-13	Electric	Vertically Integrated	7/31/2014	9.90
Vermont	Green Mountain Power Corp.		D-8190, 8191	Electric	Vertically Integrated	8/25/2014	9.60
Utah	PacifiCorp	BRK.A	D-13-035-184	Electric	Vertically Integrated	8/29/2014	9.80
Florida	Florida Public Utilities Co.	CPK	D-140025-EI	Electric	Vertically Integrated	9/15/2014	10.25
							9.90%

Q4 2014

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
Nevada	Nevada Power Co.	BRK.A	D-14-05004	Electric	Vertically Integrated	10/9/2014	9.80
Illinois	MidAmerican Energy Co.	BRK.A	D-14-0066	Electric	Vertically Integrated	11/6/2014	9.56
Wisconsin	Wisconsin Public Service Corp.	WEC	D-6690-UR-123 (Elec)	Electric	Vertically Integrated	11/6/2014	10.20
Wisconsin	Wisconsin Electric Power Co.	WEC	D-05-UR-107 (WEP-Elec)	Electric	Vertically Integrated	11/14/2014	10.20
Virginia	Appalachian Power Co.	AEP	C-PUE-2014-00026	Electric	Vertically Integrated	11/26/2014	9.70
Wisconsin	Madison Gas and Electric Co.	MGEE	D-3270-UR-120 (Elec)	Electric	Vertically Integrated	11/26/2014	10.20
Oregon	Portland General Electric Co.	POR	D-UE-283	Electric	Vertically Integrated	12/4/2014	9.68
Mississippi	Entergy Mississippi Inc.	ETR	D-2014-UN-0132	Electric	Vertically Integrated	12/11/2014	10.07
Wisconsin	Northern States Power Co - WI	XEL	D-4220-UR-120 (Elec)	Electric	Vertically Integrated	12/12/2014	10.20
Colorado	Black Hills Colorado Electric	BKH	D-14AL-0393E	Electric	Vertically Integrated	12/18/2014	9.83
							9.94%

Q1 2015

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
Wyoming	PacifiCorp	BRK.A	D-20000-446-ER-14	Electric	Vertically Integrated	1/23/2015	9.50
Colorado	Public Service Co. of CO	XEL	D-14AL-0660E	Electric	Vertically Integrated	2/24/2015	9.83
Washington	PacifiCorp	BRK.A	D-UE-140762	Electric	Vertically Integrated	3/25/2015	9.50
Minnesota	Northern States Power Co. - MN	XEL	D-E-002/GR-13-868	Electric	Vertically Integrated	3/26/2015	9.72
							9.64%

Q2 2015

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
Michigan	Wisconsin Public Service Corp.	WEC	C-U-17669	Electric	Vertically Integrated	4/23/2015	10.20
Missouri	Union Electric Co.	AEE	C-ER-2014-0258	Electric	Vertically Integrated	4/29/2015	9.53
West Virginia	Appalachian Power Co.	AEP	C-14-1152-E-42T	Electric	Vertically Integrated	5/26/2015	9.75
							9.83%

Q3 2015

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
Missouri	Kansas City Power & Light	GXP	C-ER-2014-0370	Electric	Vertically Integrated	9/2/2015	9.50
Kansas	Kansas City Power & Light	GXP	D-15-KCPE-116-RTS	Electric	Vertically Integrated	9/10/2015	9.30
							9.40%

Q4 2015

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
Wisconsin	Wisconsin Public Service Corp.	WEC	D-6690-UR-124 (Elec)	Electric	Vertically Integrated	11/19/2015	10.00
Michigan	Consumers Energy Co.	CMS	C-U-17735	Electric	Vertically Integrated	11/19/2015	10.30

Wisconsin	Northern States Power Co - WI	XEL	D-4220-UR-121 (Elec)	Electric	Vertically Integrated	12/3/2015	10.00
Michigan	DTE Electric Co.	DTE	C-U-17767	Electric	Vertically Integrated	12/11/2015	10.30
Oregon	Portland General Electric Co.	POR	D-UE-294	Electric	Vertically Integrated	12/15/2015	9.60
Texas	Southwestern Public Service Co	XEL	D-43695	Electric	Vertically Integrated	12/17/2015	9.70
Idaho	Avista Corp.	AVA	C-AVU-E-15-05	Electric	Vertically Integrated	12/18/2015	9.50
Wyoming	PacifiCorp	BRK.A	D-20000-469-ER-15	Electric	Vertically Integrated	12/30/2015	9.50
							9.86%

Q1 2016

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
Washington	Avista Corp.	AVA	D-UE-150204	Electric	Vertically Integrated	1/6/2016	9.50
Arkansas	Entergy Arkansas Inc.	ETR	D-15-015-U	Electric	Vertically Integrated	2/23/2016	9.75
Indiana	Indianapolis Power & Light Co.	AES	Ca-44576	Electric	Vertically Integrated	3/16/2016	9.85
							9.70%

Q2 2016

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
New Mexico	El Paso Electric Co.	EE	C-15-00127-UT	Electric	Vertically Integrated	6/8/2016	9.48
							9.48%

Q3 2016

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
Indiana	Northern IN Public Svc Co.	NI	Ca-44688	Electric	Vertically Integrated	7/18/2016	9.98
Tennessee	Kingsport Power Company	AEP	D-16-00001	Electric	Vertically Integrated	8/9/2016	9.85
Arizona	UNS Electric Inc.	FTS	D-E-04204A-15-0142	Electric	Vertically Integrated	8/18/2016	9.50
Washington	PacifiCorp	BRK.A	D-UE-152253	Electric	Vertically Integrated	9/1/2016	9.50
Michigan	Upper Peninsula Power Co.		C-U-17895	Electric	Vertically Integrated	9/8/2016	10.00
New Mexico	Public Service Co. of NM	PNM	C-15-00261-UT	Electric	Vertically Integrated	9/28/2016	9.58
							9.74%

Q4 2016

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
Wisconsin	Madison Gas and Electric Co.	MGEE	D-3270-UR-121 (Elec)	Electric	Vertically Integrated	11/9/2016	9.80
Oklahoma	Public Service Co. of OK	AEP	Ca-PUD201500208	Electric	Vertically Integrated	11/10/2016	9.50
Wisconsin	Wisconsin Power and Light Co	LNT	D-6680-UR-120 (Elec)	Electric	Vertically Integrated	11/18/2016	10.00
Florida	Florida Power & Light Co.	NEE	D-160021-EI	Electric	Vertically Integrated	11/29/2016	10.55
California	Liberty Utilities CalPeco Ele	AQN	A-15-05-008	Electric	Vertically Integrated	12/1/2016	10.00
South Carolina	Duke Energy Progress LLC	DUK	D-2016-227-E	Electric	Vertically Integrated	12/7/2016	10.10
Colorado	Black Hills Colorado Electric	BKH	D-16AL-0326E	Electric	Vertically Integrated	12/19/2016	9.37
Nevada	Sierra Pacific Power Co.	BRK.A	D-16-06006	Electric	Vertically Integrated	12/22/2016	9.60
North Carolina	Virginia Electric & Power Co.	D	D-E-22, Sub 532	Electric	Vertically Integrated	12/22/2016	9.90
Idaho	Avista Corp.	AVA	C-AVU-E-16-03	Electric	Vertically Integrated	12/28/2016	9.50
							9.83%

Q1 2017

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
Wyoming	MDU Resources Group Inc.	MDU	D-20004-117-ER-16	Electric	Vertically Integrated	1/18/2017	9.45
Michigan	DTE Electric Co.	DTE	C-U-18014	Electric	Vertically Integrated	1/31/2017	10.10
Arizona	Tucson Electric Power Co.	FTS	D-E-01933A-15-0322	Electric	Vertically Integrated	2/24/2017	9.75
Michigan	Consumers Energy Co.	CMS	C-U-17990	Electric	Vertically Integrated	2/28/2017	10.10
Minnesota	Otter Tail Power Co.	OTTR	D-E-017/GR-15-1033	Electric	Vertically Integrated	3/2/2017	9.41
Oklahoma	Oklahoma Gas and Electric Co.	OGE	Ca-PUD201500273	Electric	Vertically Integrated	3/20/2017	9.50
							9.72%

Q2 2017

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
Florida	Gulf Power Co.	SO	D-160186-EI	Electric	Vertically Integrated	4/4/2017	10.25
Missouri	Kansas City Power & Light	GXP	C-ER-2016-0285	Electric	Vertically Integrated	5/3/2017	9.50
Minnesota	Northern States Power Co. - MN	XEL	D-E-002/GR-15-826	Electric	Vertically Integrated	5/11/2017	9.20
Arkansas	Oklahoma Gas and Electric Co.	OGE	D-16-052-U	Electric	Vertically Integrated	5/18/2017	9.50
North Dakota	MDU Resources Group Inc.	MDU	C-PU-16-666	Electric	Vertically Integrated	6/16/2017	9.65
Kentucky	Kentucky Utilities Co.	PPL	C-2016-00370	Electric	Vertically Integrated	6/22/2017	9.70
Kentucky	Louisville Gas & Electric Co.	PPL	C-2016-00371 (elec.)	Electric	Vertically Integrated	6/22/2017	9.70
							9.64%

Q3 2017

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
Arizona	Arizona Public Service Co.	PNW	D-E-01345A-16-0036	Electric	Vertically Integrated	8/15/2017	10.00
							10.00%

Q4 2017

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
California	San Diego Gas & Electric Co.	SRE	Advice No. 3120-E	Electric	Vertically Integrated	10/26/2017	10.20
California	Pacific Gas and Electric Co.	PCG	Advise No. 3887-G/5148-E	Electric	Vertically Integrated	10/26/2017	10.25
California	Southern California Edison Co.	EIX	Advice No. 3665-E	Electric	Vertically Integrated	10/26/2017	10.30
Florida	Tampa Electric Co.	EMA	D-20170210-EI	Electric	Vertically Integrated	11/6/2017	10.25
Alaska	Alaska Electric Light Power	AVA	D-U-16-086	Electric	Vertically Integrated	11/15/2017	11.95
Washington	Puget Sound Energy Inc.		D-UE-170033	Electric	Vertically Integrated	12/5/2017	9.50
Wisconsin	Northern States Power Co - WI	XEL	D-4220-UR-123 (Elec)	Electric	Vertically Integrated	12/7/2017	9.80
Texas	Southwestern Electric Power Co	AEP	D-46449	Electric	Vertically Integrated	12/14/2017	9.60
Texas	El Paso Electric Co.	EE	D-46831	Electric	Vertically Integrated	12/14/2017	9.65
Oregon	Portland General Electric Co.	POR	D-UE-319	Electric	Vertically Integrated	12/18/2017	9.50
New Mexico	Public Service Co. of NM	PNM	C-16-00276-UT	Electric	Vertically Integrated	12/20/2017	9.58
Vermont	Green Mountain Power Corp.		C-17-3112-INV	Electric	Vertically Integrated	12/21/2017	9.10
Idaho	Avista Corp.	AVA	D-AVU-E-17-01	Electric	Vertically Integrated	12/28/2017	9.50
Nevada	Nevada Power Co.	BRK.A	D-17-06003	Electric	Vertically Integrated	12/29/2017	9.51
							9.91%

Q1 2018

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Return on Equity (%)
Kentucky	Kentucky Power Co.	AEP	C-2017-00179	Electric	Vertically Integrated	1/18/2018	9.70
Oklahoma	Public Service Co. of OK	AEP	Ca-PUD201700151	Electric	Vertically Integrated	1/31/2018	9.30
Iowa	Interstate Power & Light Co.	LNT	D-RPU-2017-0001	Electric	Vertically Integrated	2/2/2018	9.98
North Carolina	Duke Energy Progress LLC	DUK	D-E-2, Sub 1142	Electric	Vertically Integrated	2/23/2018	9.90
Minnesota	ALLETE (Minnesota Power)	ALE	D-E-015/GR-16-664	Electric	Vertically Integrated	3/12/2018	9.25
Michigan	Consumers Energy Co.	CMS	C-U-18322	Electric	Vertically Integrated	3/29/2018	10.00
							9.69%

Rate Case History (Past Rate Cases)

List	None
Company List	All
Status	All
Years	All
Service Type	Electric
Service RRA State	

Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Date	Rate Increase ($M)	Return on Original Cost Rate (%)	Return on Equity (%)	Common Equity to Total Capital (%)	Rate Base ($M)	Date	Decision Type	Rate Increase ($M)	Phase-In?	Interim Authorized?	Return on Original Cost Rate (%)	Return on Equity (%)	Common Equity to Total Capital (%)	Rate Case Test Year End Date	Rate Base ($M)	Rate Base Valuation Method	Rate Case Duration (months)	Year	Date of Electric Rate Case	Authorized ROE	30-Year Treasury	Utility BAA yield spread
New York	ED	C-13-E-0030	Electric	Distribution	1/25/2013	425.0	7.57	10.50	50.06	17,580.35	2/20/2014	Settled	(76.2)	Yes	No	7.05	9.20	48.00	12/2014	17,322.78	Average	13	2014	2/20/2014	9.20%	3.55%	1.48%
North Dakota	XEL	C-PU-12-813	Electric	Vertically Integrated	12/18/2012	14.9	7.72	10.50	52.56	375.81	2/26/2014	Settled	9.0	Yes	Yes	7.45	9.75	52.56	NA	NA	NA	14	2014	3/26/2014	9.75%	3.56%	1.48%
New Hampshire	AQN	D-DE-13-063	Electric	Distribution	3/29/2013	13.0	8.46	10.50	55.00	68.29	3/17/2014	Settled	9.8	Yes	Yes	7.92	9.55	55.00	12/2012	68.06	Year-end	11	2014	3/17/2014	9.55%	3.58%	1.47%
District of Columbia	EXC	FC-1103-2013-E	Electric	Distribution	3/8/2013	44.8	8.07	10.50	49.19	1,365.60	3/26/2014	Fully Litigated	23.4	No	No	7.65	9.40	49.19	12/2012	1,333.48	Average	12	2014	3/26/2014	9.40%	3.60%	1.46%
New Mexico	XEL	C-12-00350-UT	Electric	Vertically Integrated	12/12/2012	21.0	8.41	10.50	53.89	469.41	3/26/2014	Fully Litigated	12.7	No	No	8.26	9.96	53.89	12/2014	NA	Average	15	2014	3/26/2014	9.96%	3.60%	1.46%
Delaware	EXC	D-13-115	Electric	Distribution	3/22/2013	39.0	7.53	10.50	49.22	745.60	4/2/2014	Fully Litigated	15.1	No	Yes	7.26	9.70	49.22	12/2012	619.57	Average	12	2014	4/2/2014	9.70%	3.62%	1.45%
Texas	ETR	D-41791	Electric	Vertically Integrated	9/25/2013	38.6	8.51	10.50	48.59	1,633.82	5/16/2014	Settled	18.5	No	No	NA	9.80	NA	03/2013	NA	NA	7	2014	5/16/2014	9.80%	3.67%	1.43%
Massachusetts	UTL	DPU 13-90	Electric	Distribution	7/15/2013	6.9	8.55	10.50	47.78	52.00	5/30/2014	Fully Litigated	5.6	No	No	8.28	9.70	47.78	12/2012	51.90	Year-end	10	2014	5/30/2014	9.70%	3.67%	1.43%
Wisconsin	LNT	D-6680-UR-119 (Elec)	Electric	Vertically Integrated	4/9/2014	0.0	NA	10.50	50.46	2,329.11	6/6/2014	Fully Litigated	0.0	No	No	NA	10.40	50.46	12/2015	2,326.11	Average	1	2014	6/6/2014	10.40%	3.67%	1.42%
Maine	EMA	D-2013-00443	Electric	Distribution	12/6/2013	8.1	7.74	10.50	50.00	234.85	6/30/2014	Settled	5.3	No	No	NA	9.55	49.00	12/2012	NA	NA	6	2014	6/30/2014	9.55%	3.66%	1.41%
Maryland	EXC	C-9336	Electric	Distribution	12/4/2013	37.4	7.92	10.50	49.18	1,414.15	7/2/2014	Fully Litigated	8.8	No	No	7.61	9.62	49.18	09/2013	1,293.35	Average	7	2014	7/2/2014	9.62%	3.66%	1.40%
Louisiana	ETR	D-UD-13-01	Electric	Vertically Integrated	3/28/2013	11.4	8.19	10.50	52.80	106.73	7/10/2014	Settled	9.3	Yes	No	NA	9.95	NA	NA	NA	NA	15	2014	7/10/2014	9.95%	3.66%	1.40%
New Jersey	ED	D-ER-13111135	Electric	Distribution	11/27/2013	23.3	8.23	10.50	52.20	194.70	7/23/2014	Settled	13.0	No	No	7.83	9.75	50.35	03/2014	172.19	Year-end	7	2014	7/23/2014	9.75%	3.64%	1.39%
Maine	IBE	D-2013-00168	Electric	Distribution	5/1/2013	41.4	7.59	10.50	50.00	800.00	7/29/2014	Settled	24.3	No	No	7.06	9.45	50.00	12/2012	762.00	Average	15	2014	7/29/2014	9.45%	3.63%	1.39%
Wyoming	BKH	D-20003-132-ER-13	Electric	Vertically Integrated	12/2/2013	12.8	8.32	10.50	54.00	376.00	7/31/2014	Settled	8.4	No	No	7.98	9.90	54.00	06/2013	376.82	Year-end	8	2014	7/31/2014	9.90%	3.63%	1.39%
New Jersey	EXC	D-ER-14030245	Electric	Distribution	3/14/2014	61.7	8.01	10.50	50.04	1,353.02	8/20/2014	Settled	19.0	No	No	7.75	9.75	49.83	12/2013	1,162.00	Year-end	5	2014	8/20/2014	9.75%	3.60%	1.39%
Vermont		D-8190, 8191	Electric	Vertically Integrated	12/20/2013	(0.2)	7.61	10.50	48.97	1,187.00	8/25/2014	Settled	(8.8)	No	No	7.46	9.60	50.00	09/2013	1,164.74	Average	8	2014	8/25/2014	9.60%	3.59%	1.39%
Utah	BRK.A	D-13-035-184	Electric	Vertically Integrated	1/3/2014	76.3	7.72	10.50	51.60	6,029.33	8/29/2014	Settled	54.2	Yes	No	7.57	9.80	51.43	06/2015	NA	NA	7	2014	8/29/2014	9.80%	3.58%	1.39%
Texas	NEE	D-42469	Electric	Transmission	5/15/2014	91.3	6.66	10.50	45.00	693.86	9/11/2014	Settled	87.8	No	No	6.37	9.60	45.00	03/2014	693.86	Year-end	3	2014	9/11/2014	9.60%	3.56%	1.39%
Florida	CPK	D-140025-EI	Electric	Vertically Integrated	4/28/2014	5.9	7.18	10.50	46.47	60.60	9/15/2014	Settled	3.8	No	Yes	NA	10.25	NA	09/2015	NA	NA	4	2014	9/15/2014	10.25%	3.56%	1.39%
Nevada	BRK.A	D-14-05004	Electric	Vertically Integrated	5/2/2014	37.8	8.25	10.50	48.17	5,249.68	10/9/2014	Settled	0.0	No	No	8.09	9.80	48.17	12/2013	NA	NA	5	2014	10/9/2014	9.80%	3.52%	1.39%
Illinois	BRK.A	D-14-0093	Electric	Vertically Integrated	12/16/2013	20.9	7.72	10.50	51.73	334.84	11/6/2014	Fully Litigated	16.4	No	No	7.14	9.56	51.73	12/2012	334.12	Year-end	10	2014	11/6/2014	9.56%	3.46%	1.41%
Wisconsin	WEC	D-6690-UR-123 (Elec)	Electric	Vertically Integrated	4/1/2014	76.8	8.72	10.50	50.50	1,579.76	11/6/2014	Fully Litigated	24.6	No	No	8.39	10.20	50.28	12/2015	1,549.92	Average	7	2014	11/6/2014	10.20%	3.46%	1.41%
Wisconsin	WEC	D-05-UR-107 (WEP-Elec)	Electric	Vertically Integrated	5/30/2014	78.5	8.60	10.50	51.90	4,432.94	11/14/2014	Fully Litigated	15.4	No	No	8.60	10.20	51.90	12/2015	4,432.94	Average	5	2014	11/14/2014	10.20%	3.44%	1.42%
Virginia	AEP	C-PUE-2014-00026	Electric	Vertically Integrated	3/31/2014	0.0	7.47	10.50	45.14	2,372.98	11/26/2014	Fully Litigated	0.0	No	No	6.88	9.70	42.89	12/2013	NA	NA	8	2014	11/26/2014	9.70%	3.42%	1.43%
Wisconsin	MGEE	D-3270-UR-120 (Elec)	Electric	Vertically Integrated	4/17/2014	11.5	8.02	10.50	58.90	575.19	11/26/2014	Fully Litigated	15.4	No	No	7.96	10.20	58.96	12/2015	575.85	Average	7	2014	11/26/2014	10.20%	3.42%	1.43%
Oregon	POR	D-UE-283	Electric	Vertically Integrated	3/13/2014	110.6	7.78	10.50	50.00	3,859.79	12/4/2014	Settled	44.3	No	No	7.56	9.68	50.00	12/2015	3,785.42	Year-end	9	2014	12/4/2014	9.68%	3.40%	1.44%
Mississippi	ETR	D-2014-UN-0132	Electric	Vertically Integrated	6/10/2014	204.5	7.81	10.50	NA	2,022.49	12/11/2014	Settled	177.7	No	No	7.51	10.07	NA	12/2015	2,014.33	Average	6	2014	12/11/2014	10.07%	3.38%	1.45%
Wisconsin	XEL	D-4220-UR-120 (Elec)	Electric	Vertically Integrated	5/30/2014	20.6	NA	10.50	52.54	NA	12/12/2014	Fully Litigated	14.2	No	No	NA	10.20	52.54	12/2015	NA	NA	6	2014	12/12/2014	10.20%	3.37%	1.45%
Connecticut	ES	D-14-05-06	Electric	Distribution	6/9/2014	221.1	7.84	10.50	50.38	3,406.47	12/17/2014	Fully Litigated	152.7	No	No	7.31	9.17	50.38	12/2013	3,396.54	Average	6	2014	12/17/2014	9.17%	3.36%	1.46%
Colorado	BKH	D-14AL-0393E	Electric	Vertically Integrated	4/30/2014	13.2	7.83	10.50	50.54	457.78	12/18/2014	Fully Litigated	9.2	No	No	7.55	9.83	49.83	12/2013	448.334572	Average	7	2014	12/18/2014	9.83%	3.35%	1.46%
Wyoming	BRK.A	D-20000-446-ER-14	Electric	Vertically Integrated	3/3/2014	32.6	7.67	10.50	51.43	2,072.88	1/23/2015	Fully Litigated	20.2	No	No	7.41	9.50	51.43	06/2015	2,067.00	Average	10	2015	1/23/2015	9.50%	3.23%	1.52%
Colorado	XEL	D-14AL-0660E	Electric	Vertically Integrated	6/17/2014	28.5	7.79	10.50	56.00	6,388.20	2/04/2015	Settled	(39.4)	No	Yes	7.55	9.83	56.00	12/2013	NA	Year-end	8	2015	2/04/2015	9.83%	3.13%	1.57%
New Jersey	FE	D-ER-12111052	Electric	Distribution	11/30/2012	11.0	8.66	10.50	53.80	2,024.17	3/18/2015	Fully Litigated	(115.0)	No	No	8.01	9.75	50.00	12/2011	1,830.02	Year-end	27	2015	3/18/2015	9.75%	3.07%	1.60%
Washington	BRK.A	D-UE-140762	Electric	Vertically Integrated	5/1/2014	30.4	7.67	10.50	51.73	829.00	3/25/2015	Fully Litigated	9.6	No	No	7.30	9.50	49.1	12/2013	818.890801	Average	10	2015	3/25/2015	9.50%	3.05%	1.61%
Minnesota	XEL	D-E-002/GR-13-868	Electric	Vertically Integrated	11/4/2013	248.1	7.65	10.50	52.50	7,042.00	3/26/2015	Fully Litigated	148.4	Yes	No	7.37	9.72	52.50	12/2014	6,988.29	Average	16	2015	3/26/2015	9.72%	3.05%	1.61%
Michigan	WEC	C-U-17669	Electric	Vertically Integrated	10/17/2014	5.7	6.21	10.50	40.82	61.25	4/23/2015	Settled	4.0	Yes	No	6.01	10.20	NA	12/2015	NA	NA	6	2015	4/23/2015	10.20%	2.98%	1.65%
Missouri	AEE	C-ER-2014-0258	Electric	Vertically Integrated	7/3/2014	181.2	8.05	10.50	51.76	6,976.39	4/29/2015	Fully Litigated	121.5	No	No	7.60	9.53	51.76	03/2014	6,976.28	Year-end	10	2015	4/29/2015	9.53%	2.96%	1.66%
Texas		D-43850	Electric	Transmission	12/23/2014	33.2	6.95	10.50	45.00	446.72	5/1/2015	Settled	30.9	No	No	6.11	9.60	40.00	09/2014	446.72	Year-end	4	2015	5/1/2015	9.60%	2.96%	1.67%
West Virginia	AEP	C-14-1152-E-42T	Electric	Vertically Integrated	6/30/2014	226.1	7.79	10.50	47.16	3,992.89	5/26/2015	Fully Litigated	123.5	No	No	7.38	9.75	47.16	12/2013	3,700.12	Average	11	2015	5/26/2015	9.75%	2.93%	1.71%
New York	FTS	C-14-E-0318	Electric	Distribution	7/25/2014	40.1	6.82	10.50	48.00	850.81	6/17/2015	Settled	15.3	Yes	No	6.62	9.00	48.00	06/2016	830.69	Average	10	2015	6/17/2015	9.00%	2.91%	1.75%
New York	ED	C-15-E-0050/C-13-E-0030 (Eut)	Electric	Distribution	1/30/2015	368.1	7.35	10.50	48.00	18,134.00	6/17/2015	Settled	0.0	No	No	6.91	9.00	48.00	12/2016	18,282.00	Average	4	2015	6/17/2015	9.00%	2.91%	1.75%
Missouri	EVRG	C-ER-2014-0370	Electric	Vertically Integrated	10/30/2014	112.7	7.93	10.50	50.09	2,584.14	9/2/2015	Fully Litigated	89.7	No	No	7.53	9.50	50.09	03/2014	2,580.07	Year-end	10	2015	9/2/2015	9.50%	2.85%	1.93%
Kansas	EVRG	D-15-KCPE-116-RTS	Electric	Vertically Integrated	1/2/2015	56.3	7.94	10.50	50.48	2,087.48	9/10/2015	Fully Litigated	40.1	No	No	7.44	9.30	50.48	06/2014	2,115.96	Year-end	8	2015	9/10/2015	9.30%	2.84%	1.95%
New York	ED	C-14-E-0493	Electric	Distribution	11/14/2014	33.9	7.51	10.50	48.00	821.55	10/15/2015	Settled	9.3	Yes	No	7.10	9.00	48.00	10/2016	763.16	Average	11	2015	10/15/2015	9.00%	2.83%	2.03%
Wisconsin	WEC	D-6690-UR-124 (Elec)	Electric	Vertically Integrated	4/17/2015	96.9	8.27	10.50	50.52	1,840.57	11/19/2015	Fully Litigated	(7.9)	No	No	8.24	10.00	50.47	12/2016	1,745.69	Average	7	2015	11/19/2015	10.00%	2.82%	2.11%
Michigan	CMS	C-U-17735	Electric	Vertically Integrated	12/5/2014	198.6	6.38	10.50	41.50	9,247.69	11/19/2015	Fully Litigated	126.4	Yes	Yes	6.18	10.30	41.50	05/2016	9,160.09	Average	11	2015	11/19/2015	10.30%	2.82%	2.11%
Wisconsin	XEL	D-4220-UR-121 (Elec)	Electric	Vertically Integrated	5/29/2015	27.4	8.07	10.50	52.59	1,188.89	12/3/2015	Fully Litigated	7.6	No	No	7.81	10.00	52.49	12/2016	1,175.23	Average	6	2015	12/3/2015	10.00%	2.83%	2.14%
Michigan	DTE	DTE Electric Co.	Electric	Vertically Integrated	12/19/2014	348.7	5.87	10.50	38.03	13,549.15	12/11/2015	Fully Litigated	242.7	No	Yes	5.70	10.30	38.03	06/2016	13,431.97	Average	11	2015	12/11/2015	10.30%	2.83%	2.15%
Oregon	POR	D-UE-294	Electric	Vertically Integrated	2/12/2015	122.3	7.67	10.50	50.00	4,470.48	12/15/2015	Settled	70.4	Yes	No	7.51	9.60	50.00	12/2016	4,440.31	Year-end	10	2015	12/15/2015	9.60%	2.83%	2.16%
Texas	XEL	D-43695	Electric	Vertically Integrated	12/8/2014	42.1	8.28	10.50	53.97	1,538.38	12/17/2015	Fully Litigated	(4.0)	No	No	7.88	9.70	51.00	06/2014	1394.571637	Year-end	12	2015	12/17/2015	9.70%	2.84%	2.16%
Idaho	AVA	C-AVU-E-15-05	Electric	Vertically Integrated	6/1/2015	26.9	7.62	10.50	50.00	766.97	12/18/2015	Settled	1.7	No	No	7.42	9.50	50.00	12/2014	735.02	Average	6	2015	12/18/2015	9.50%	2.84%	2.17%
Wyoming	BRK.A	D-20000-499-ER-15	Electric	Vertically Integrated	1/2/2015	26.9	7.69	10.50	51.44	2,120.36	12/28/2015	Fully Litigated	16.3	No	No	7.41	9.50	51.44	12/2015	2,087.28	Average	10	2015	12/28/2015	9.50%	2.85%	2.18%
Washington	AVA	D-UE-150204	Electric	Vertically Integrated	2/9/2015	33.2	7.46	10.50	48.00	1,464.30	1/6/2016	Settled	(8.1)	No	No	7.29	9.50	48.50	09/2014	1,315.89	NA	11	2016	1/6/2016	9.50%	2.86%	2.18%
Arkansas	ETR	D-15-015-U	Electric	Vertically Integrated	4/24/2015	268.5	4.86	10.50	30.16	5,928.76	2/23/2016	Settled	219.7	No	No	4.52	9.75	28.46	03/2015	NA	NA	10	2016	2/23/2016	9.75%	2.89%	2.29%
Indiana	AES	Ca-44576	Electric	Vertically Integrated	12/26/2014	65.6	6.91	10.50	37.33	1,964.99	3/16/2016	Fully Litigated	29.6	No	No	6.51	9.85	37.33	06/2014	1,887.31	Year-end	14	2016	3/16/2016	9.85%	2.89%	2.32%
Massachusetts	UTL	DPU 15-80	Electric	Distribution	6/16/2015	3.8	8.72	10.50	52.92	57.25	4/29/2016	Fully Litigated	2.1	No	No	8.46	9.80	52.17	12/2014	57.16	Year-end	10	2016	4/29/2016	9.80%	2.88%	2.38%
Maryland	EXC	C-9406 (elec)	Electric	Distribution	11/6/2015	115.6	7.95	10.50	53.70	3,003.09	6/3/2016	Fully Litigated	44.1	No	No	7.28	9.75	51.90	11/2015	2,934.73	Average	7	2016	6/3/2016	9.75%	2.84%	2.38%
New Mexico	EE	C-15-00127-UT	Electric	Vertically Integrated	5/11/2015	6.4	7.90	10.50	49.29	435.96	6/8/2016	Fully Litigated	1.1	NA	NA	7.67	9.48	49.29	12/2014	414.46	Year-end	13	2016	6/8/2016	9.48%	2.83%	2.39%
New York	IBE	C-15-E-0283	Electric	Distribution	5/20/2015	123.8	7.32	10.50	50.00	1,797.60	6/15/2016	Settled	29.6	Yes	No	6.68	9.00	48.00	04/2017	1,752.85	Average	13	2016	6/15/2016	9.00%	2.82%	2.39%
New York	IBE	C-15-E-0285	Electric	Distribution	5/20/2015	42.5	8.15	10.50	50.00	1,240.69	6/15/2016	Settled	3.0	No	No	7.55	9.00	48.00	04/2017	1,146.36	Average	13	2016	6/15/2016	9.00%	2.82%	2.39%
Indiana	NI	Ca-44688	Electric	Vertically Integrated	10/1/2015	119.5	6.78	10.50	45.20	3,437.72	7/18/2016	Settled	72.5	No	No	6.74	9.98	47.42	03/2015	3,221.42	Year-end	9	2016	7/18/2016	9.98%	2.75%	2.38%
Tennessee	AEP	D-16-00001	Electric	Vertically Integrated	1/4/2016	12.1	6.69	10.50	42.43	71.50	8/9/2016	Settled	8.6	No	No	6.18	9.85	40.25	12/2017	82.75	Average	7	2016	8/9/2016	9.85%	2.71%	2.35%
Arizona	FTS	D-E-04204A-15-0142	Electric	Vertically Integrated	5/5/2015	15.1	7.22	10.50	52.83	270.29	8/18/2016	Fully Litigated	15.1	No	No	7.22	9.50	52.83	12/2014	270.29	Year-end	17	2016	8/18/2016	9.50%	2.69%	2.34%
New Jersey	EXC	D-ER-16030252	Electric	Distribution	3/22/2016	79.4	8.06	10.50	49.48	1,300.00	8/24/2016	Settled	45.0	No	No	7.64	9.75	49.48	12/2015	1,205.96	Year-end	5	2016	8/24/2016	9.75%	2.68%	2.33%
Washington	BRK.A	D-UE-152253	Electric	Vertically Integrated	11/25/2015	20.3	7.30	10.50	49.10	874.15	9/1/2016	Fully Litigated	13.7	Yes	No	7.30	9.50	49.10	06/2015	808.33	Year-end	9	2016	9/1/2016	9.50%	2.66%	2.32%
Michigan		Upper Peninsula	Electric	Vertically Integrated	9/18/2015	8.5	7.87	10.50	54.13	243.55	9/8/2016	Fully Litigated	4.6	No	Yes	7.47	10.00	53.49	12/2016	242.34	Average	11	2016	9/8/2016	10.00%	2.65%	2.32%
New Mexico	PNM	C-15-00261-UT	Electric	Vertically Integrated	8/27/2015	123.5	8.17	10.50	49.61	2,458.09	9/28/2016	Fully Litigated	61.2	No	No	7.71	9.58	49.61	09/2016	2,263.00	Average	13	2016	9/28/2016	9.58%	2.62%	2.28%
Massachusetts	NG	DPU-15-155	Electric	Distribution	11/6/2015	201.9	8.13	10.50	51.98	1,799.53	9/30/2016	Fully Litigated	169.7	No	No	7.58	9.90	50.70	06/2015	1,783.12	Year-end	10	2016	9/30/2016	9.90%	2.62%	2.28%
Wisconsin	MGEE	D-3270-UR-121 (Elec)	Electric	Vertically Integrated	4/8/2016	6.9	8.32	10.50	58.06	573.37	11/9/2016	Fully Litigated	(3.2)	No	No	7.89	9.80	57.16	12/2017	570.778	Average	7	2016	11/9/2016	9.80%	2.57%	2.21%
Oklahoma	AEP	Cs-PUD201500208	Electric	Vertically Integrated	7/1/2015	84.4	7.60	10.50	48.00	2,062.16	11/10/2016	Fully Litigated	14.5	No	Yes	6.94	9.50	44.00	03/2015	2,024.77	Year-end	16	2016	11/10/2016	9.50%	2.57%	2.20%
Maryland	EXC	C-9418	Electric	Distribution	4/19/2016	102.8	8.01	10.50	49.55	1,728.57	11/15/2016	Fully Litigated	52.5	No	No	7.49	9.55	49.55	12/2015	1,636.94	Average	7	2016	11/15/2016	9.55%	2.57%	2.20%
Wisconsin	LNT	D-6680-UR-120 (Elec)	Electric	Vertically Integrated	5/20/2016	12.9	7.91	10.50	52.20	2,851.38	11/18/2016	Settled	9.4	Yes	No	7.91	10.00	52.20	12/2018	2,851.38	Average	6	2016	11/18/2016	10.00%	2.57%	2.19%
Florida	NEE	D-160021-EI	Electric	Vertically Integrated	3/15/2016	1,304.6	6.70	10.50	45.35	33,893.50	11/29/2016	Settled	811.0	Yes	No	NA	10.55	NA	12/2018	NA	NA	8	2016	11/29/2016	10.55%	2.57%	2.17%
California	AQN	A-15-05-008	Electric	Distribution	5/1/2015	11.4	7.92	10.50	55.00	150.93	12/1/2016	Settled	8.3	No	No	7.51	10.00	52.50	12/2016	145.66	Average	19	2016	12/1/2016	10.00%	2.57%	2.16%
South Carolina	DUK	D-2016-227-E	Electric	Vertically Integrated	7/1/2016	79.0	7.55	10.50	53.00	1,318.99	12/7/2016	Settled	56.2	Yes	No	7.21	10.10	53.00	12/2015	1,305.96	Year-end	5	2016	12/7/2016	10.10%	2.57%	2.15%
New Jersey	FE	D-ER-16040383	Electric	Distribution	4/28/2016	142.1	8.69	10.50	54.00	2,229.13	12/12/2016	Settled	80.0	No	No	7.47	9.60	45.00	06/2016	2,217.12	Year-end	7	2016	12/12/2016	9.60%	2.57%	2.14%
Connecticut	IBE	D-16-06-04	Electric	Distribution	7/1/2016	98.3	7.58	10.50	52.00	1,032.64	12/14/2016	Fully Litigated	57.4	Yes	No	7.08	9.10	50.00	12/2015	1,014.14	Average	5	2016	12/14/2016	9.10%	2.57%	2.13%
Maine	EMA	D-2015-00360	Electric	Distribution	3/21/2016	7.2	7.72	10.50	49.00	262.81	12/19/2016	Fully Litigated	3.0	No	No	7.45	9.00	49.00	12/2014	259.64	Average	9	2016	12/19/2016	9.00%	2.58%	2.12%
Colorado	BKH	D-16AL-0326E	Electric	Vertically Integrated	5/3/2016	14.4	7.56	10.50	50.92	510.73	12/19/2016	Fully Litigated	0.6	No	No	7.43	9.37	52.39	12/2015	414.59	Average	7	2016	12/19/2016	9.37%	2.58%	2.12%
Nevada	BRK.A	D-16-06006	Electric	Vertically Integrated	6/6/2016	21.6	6.97	10.50	48.03	1,652.55	12/22/2016	Settled	(2.9)	No	No	6.65	9.60	48.03	12/2015	NA	NA	6	2016	12/22/2016	9.60%	2.58%	2.11%
North Carolina	D	D-E-22, Sub 532	Electric	Vertically Integrated	3/31/2016	46.8	7.80	10.50	53.92	1,047.15	12/22/2016	Settled	34.7	No	No	7.37	9.90	51.75	12/2015	1,040.04	Year-end	8	2016	12/22/2016	9.90%	2.58%	2.11%
Idaho	AVA	C-AVU-E-16-03	Electric	Vertically Integrated	5/26/2016	15.4	7.78	10.50	50.00	754.64	12/28/2016	Settled	6.3	No	No	7.58	9.50	50.00	12/2015	754.00	Average	7	2016	12/28/2016	9.50%	2.58%	2.10%
Wyoming	MDU Resources	D-20004-117-ER-16	Electric	Vertically Integrated	6/10/2016	3.2	8.00	10.50	50.99	72.31	1/18/2017	Settled	2.7	No	No	7.25	9.45	50.99	12/2015	72.21	Year-end	7	2017	1/18/2017	9.45%	2.59%	2.04%
New York	ED	C-16-E-0060	Electric	Distribution	1/29/2016	479.6	7.31	10.50	48.00	18,926.57	1/24/2017	Settled	194.5	No	No	6.82	9.00	48.00	12/2017	18,902.00	Average	12	2017	1/24/2017	9.00%	2.60%	2.02%
Michigan	DTE	DTE Electric Co.	Electric	Vertically Integrated	1/12/2016	325.2	5.71	10.50	37.49	14,444.51	1/31/2017	Fully Litigated	184.3	Yes	Yes	5.55	10.10	37.49	07/2017	14,243.72	Average	12	2017	1/31/2017	10.10%	2.61%	1.99%
Maryland	EXC	C-9424	Electric	Distribution	7/20/2016	57.0	7.24	10.50	49.10	726.80	2/15/2017	Fully Litigated	38.3	No	No	6.74	9.60	49.1	03/2016	707.246234	Average	7	2017	2/15/2017	9.60%	2.63%	1.94%
New Jersey	ED	D-ER-16050428	Electric	Distribution	5/13/2016	8.8	7.79	10.50	49.81	190.12	2/22/2017	Settled	1.7	No	No	7.47	9.60	49.70	12/2016	178.727	Year-end	9	2017	2/22/2017	9.60%	2.64%	1.92%
Arizona	FTS	D-E-01933A-15-0322	Electric	Vertically Integrated	11/5/2015	109.5	7.34	10.50	50.03	2,104.68	2/24/2017	Settled	81.5	No	No	7.04	9.75	50.03	06/2015	2045.20346	Year-end	15	2017	2/24/2017	9.75%	2.64%	1.91%
Michigan	CMS	C-U-17990	Electric	Vertically Integrated	3/1/2016	208.2	6.18	10.50	40.75	10,187.09	2/28/2017	Fully Litigated	113.3	No	No	5.94	10.10	40.75	08/2017	10,159.17	Average	12	2017	2/28/2017	10.10%	2.64%	1.91%
Minnesota	OTTR	D-E-017/GR-15-1033	Electric	Vertically Integrated	2/16/2016	14.6	7.85	10.50	52.50	482.36	3/2/2017	Fully Litigated	12.3	No	Yes	7.51	9.41	52.50	12/2016	487.19	Average	12	2017	3/2/2017	9.41%	2.64%	1.90%
Oklahoma	OGE	Cs-PUD201500273	Electric	V

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Maryland	Potomac Electric Power Co.	EXC	C-8251	Electric	Vertically Integrated	2/1/1990	24.0	10.11	10.50	43.16	NA	5/29/1990	Settled	13.8	No	No	NA	NA	NA	NA	NA	NA	3
Minnesota	Northern States Power Co. - Minnesota	XEL	D-E-002-GR-89-865	Electric	Vertically Integrated	11/2/1989	120.8	10.20	10.50	47.03	NA	8/6/1990	Fully Litigated	0.0	No	Yes	NA	NA	NA	NA	NA	NA	9
Missouri	Empire District Electric Co.	AQN	C-ER-90-138	Electric	Vertically Integrated	12/26/1989	8.2	11.07	10.50	48.90	NA	8/31/1990	Fully Litigated	5.7	No	No	NA	NA	NA	NA	NA	NA	8
Maine	Emera Maine	EMA	D-90-001	Electric	Vertically Integrated	3/9/1990	9.1	11.87	10.50	40.00	NA	9/17/1990	Fully Litigated	1.6	No	Yes	NA	NA	NA	12/1989	NA	Average	6
Texas	AEP Texas Central Co.	AEP	D-9561	Electric	Vertically Integrated	5/17/1990	120.0	11.13	10.50	44.80	NA	12/19/1990	Settled	120.0	No	No	NA	NA	NA	12/1989	NA	Year-end	7
Texas	Entergy Texas Inc.	ETR	D-8702	Electric	Vertically Integrated	3/21/1989	103.0	12.52	10.50	39.11	NA	3/22/1991	Settled	30.0	No	Yes	NA	NA	NA	09/1988	NA	Year-end	24
Washington	Puget Sound Energy Inc.		Cs-UE-90-1183-TJH-P	Electric	Vertically Integrated	11/5/1990	19.2	NA	10.5	NA	NA	4/1/1991	Fully Litigated	0.0	No	No	NA	NA	NA	NA	NA	NA	4
Massachusetts	Western Massachusetts Electric Co.	ES	DPU-90-300	Electric	Vertically Integrated	12/14/1990	54.9	10.67	10.50	37.45	NA	7/1/1991	Settled	32.2	No	No	NA	NA	NA	09/1990	NA	Year-end	6
Colorado	Public Service Co. of CO	XEL	D-91S-091E	Electric	Vertically Integrated	1/31/1991	(23.6)	10.68	10.50	47.84	NA	7/3/1991	Settled	(36.0)	No	No	NA	NA	NA	NA	NA	NA	5
Massachusetts	Massachusetts Electric Co.	NG	DPU-91-52	Electric	Vertically Integrated	3/15/1991	35.6	10.65	10.50	46.54	NA	9/6/1991	Settled	17.0	No	No	NA	NA	NA	12/1990	NA	Year-end	5
Arizona	Tucson Electric Power Co.	FTS	D-U-1933-90-270	Electric	Vertically Integrated	9/21/1990	50.4	10.32	10.50	40.00	NA	10/11/1991	Settled	71.0	No	No	7.87	NA	NA	09/1990	NA	Year-end	12
Arizona	Arizona Public Service Co.	PNW	D-U-1345-90-007	Electric	Vertically Integrated	1/11/1990	208.5	10.75	10.50	41.28	NA	12/5/1991	Settled	66.5	No	Yes	8.38	NA	NA	12/1990	NA	Year-end	23
Maryland	Delmarva Power & Light Co.	EXC	C-8369	Electric	Vertically Integrated	8/30/1991	9.2	10.31	10.50	42.86	NA	12/30/1991	Settled	5.5	No	No	NA	NA	NA	09/1991	NA	NA	4
Massachusetts	Western Massachusetts Electric	ES	DPU-91-290	Electric	Vertically Integrated	12/13/1991	37.4	10.47	10.50	37.43	NA	6/30/1992	Settled	23.0	Yes	No	NA	NA	NA	NA	NA	NA	6
Ohio	Columbus Southern Power Co.	AEP	C-91-1610-EL-AIR	Electric	Vertically Integrated	10/4/1991	7.7	10.31	10.50	44.85	NA	7/15/1992	Settled	3.3	No	No	9.93	NA	NA	12/1991	65.90	Date Certain	9
Maryland	Potomac Electric Power Co.	EXC	C-8466	Electric	Vertically Integrated	6/22/1992	86.4	10.39	10.50	45.96	NA	10/27/1992	Settled	29.3	Yes	No	NA	NA	NA	NA	NA	NA	4
South Dakota	Northern States Power Co. - Minnesota	XEL	D-EL-92-016	Electric	Vertically Integrated	6/29/1992	6.3	10.16	10.50	49.90	NA	12/15/1992	Settled	4.2	Yes	No	NA	NA	NA	12/1991	NA	Average	5
Massachusetts	Eastern Edison Company		DPU-92-148	Electric	Vertically Integrated	6/15/1992	16.4	11.02	10.50	40.01	NA	12/30/1992	Settled	8.1	No	No	NA	NA	NA	12/1991	NA	Year-end	6
Maryland	Delmarva Power & Light Co.	EXC	C-8462	Electric	Vertically Integrated	10/30/1992	14.6	10.07	10.50	46.00	NA	3/29/1993	Settled	7.8	No	No	NA	NA	NA	NA	NA	NA	4
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-93-37	Electric	Vertically Integrated	7/31/1992	19.4	11.08	10.50	44.75	NA	6/18/1993	Settled	4.9	No	No	NA	NA	NA	09/1992	NA	Year-end	10
Ohio	Duke Energy Ohio Inc.	DUK	C-92-1464-EL-AIR	Electric	Vertically Integrated	9/18/1992	86.1	10.57	10.50	43.65	NA	8/26/1993	Settled	41.1	No	No	NA	NA	NA	09/1992	NA	Date Certain	11
Delaware	Delmarva Power & Light Co.	EXC	D-92-85	Electric	Vertically Integrated	10/30/1992	36.6	9.73	10.50	46.00	NA	10/5/1993	Settled	24.9	Yes	No	NA	NA	NA	12/1992	NA	Average	11
Maryland	Potomac Electric Power Co.	EXC	C-8585	Electric	Vertically Integrated	6/2/1993	49.9	9.89	10.50	44.79	NA	10/13/1993	Settled	27.0	No	No	NA	NA	NA	06/1993	NA	Average	4
Oklahoma	Public Service Co. of OK	AEP	Cs-PUD-920000-1342	Electric	Vertically Integrated	6/19/1992	41.6	9.98	10.50	51.17	NA	12/23/1993	Fully Litigated	14.4	No	No	NA	NA	NA	12/1992	NA	Average	18
Texas	Entergy Texas Inc.	ETR	D-12423	Electric	Vertically Integrated	9/29/1993	NA	NA	10.5	NA	NA	12/29/1993	Settled	(42.5)	No	No	NA	NA	NA	12/1993	NA	Year-end	3
Arizona	Arizona Public Service Co.	PNW	D-U-1345-94-120	Electric	Vertically Integrated	4/20/1994	(38.3)	NA	10.5	NA	NA	5/27/1994	Settled	(38.3)	No	No	NA	NA	NA	NA	NA	NA	1
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-94-163	Electric	Vertically Integrated	11/22/1993	5.1	10.46	10.50	55.20	NA	6/3/1994	Settled	2.2	No	No	NA	NA	NA	NA	NA	NA	6
Nevada	Nevada Power Co.	NSW A	Ds-93-1104	Electric	Vertically Integrated	12/27/1993	78.1	9.70	10.50	NA	NA	7/14/1994	Settled	(47.5)	No	No	NA	NA	NA	NA	NA	NA	6
Missouri	Empire District Electric Co.	AQN	C-ER-94-174	Electric	Vertically Integrated	12/1/1993	8.0	10.23	10.50	49.44	NA	8/2/1994	Settled	7.4	No	No	NA	NA	NA	NA	NA	NA	8
New Mexico	Southwestern Public Service Co.	XEL	C-2573	Electric	Vertically Integrated	2/25/1994	(4.0)	NA	10.5	NA	NA	9/6/1994	Settled	(4.0)	No	No	NA	NA	NA	09/1992	NA	Year-end	6
Maryland	Potomac Edison Co.	FE	C-8652	Electric	Vertically Integrated	4/15/1994	30.9	9.46	10.50	42.85	NA	9/20/1994	Settled	19.6	No	No	NA	NA	NA	12/1993	NA	Average	5
Texas	Texas-New Mexico Power Co.	PNM	D-12900	Electric	Vertically Integrated	3/30/1994	34.8	11.50	10.50	24.00	NA	10/6/1994	Settled	17.5	No	No	NA	NA	NA	09/1993	NA	Year-end	6
Nevada	Sierra Pacific Power Co.	BRK-A	D-94-6020	Electric	Vertically Integrated	6/15/1994	16.6	9.54	10.50	45.56	NA	10/12/1994	Settled	0.0	No	No	NA	NA	NA	03/1994	NA	Year-end	3
Oklahoma	Oklahoma Gas and Electric Co.	OGE	Cs-PUD-940000413	Electric	Vertically Integrated	8/9/1994	(12.0)	NA	10.5	NA	NA	10/26/1994	Settled	(15.0)	No	No	NA	NA	NA	NA	NA	NA	2
Montana	NorthWestern Corp.	NWE	D-94.8.30	Electric	Vertically Integrated	8/22/1994	24.7	9.72	10.50	46.95	NA	4/18/1995	Settled	13.9	No	Yes	NA	NA	NA	12/1993	NA	Year-end	7
South Dakota	Black Hills Power Inc.	BKH	D-EL-95-003	Electric	Vertically Integrated	2/1/1995	8.4	10.13	10.50	45.00	NA	6/30/1995	Settled	5.7	No	No	NA	NA	NA	09/1994	NA	Average	4
Iowa	MidAmerican Energy Co.	BRK-A	D-RPU-94-4	Electric	Vertically Integrated	9/15/1994	61.0	10.36	10.50	46.53	NA	7/10/1995	Settled	20.3	No	No	NA	NA	NA	NA	NA	NA	9
Missouri	Union Electric Co.	AEE	C-ER-95-411	Electric	Vertically Integrated	6/15/1995	(30.0)	NA	10.5	NA	NA	7/31/1995	Settled	(30.0)	No	No	NA	NA	NA	NA	NA	NA	1
Indiana	Indianapolis Power & Light Co.	AES	Cs-39938	Electric	Vertically Integrated	10/11/1994	87.6	9.88	10.50	41.71	NA	8/24/1995	Settled	60.0	Yes	No	NA	NA	NA	NA	NA	NA	10
Texas	CenterPoint Energy Houston	CNP	D-12065	Electric	Vertically Integrated	7/13/1994	248.0	10.43	10.50	51.00	NA	8/30/1995	Settled	(62.0)	No	No	NA	NA	51.22	12/1993	NA	Year-end	13
Texas	El Paso Electric Co.	EE	D-12700	Electric	Vertically Integrated	1/10/1994	41.4	NA	10.5	NA	NA	8/30/1995	Settled	24.9	No	Yes	NA	NA	NA	09/1993	NA	NA	19
Missouri	Empire District Electric Co.	AQN	C-ER-95-279	Electric	Vertically Integrated	3/17/1995	8.5	10.38	10.50	46.98	NA	11/3/1995	Settled	1.4	No	No	NA	NA	NA	NA	NA	NA	7
California	Southern California Edison Co.	EIX	AP-9312025 De-9610211	Electric	Vertically Integrated	12/23/1993	117.3	9.17	10.50	47.25	NA	1/10/1996	Settled	(76.0)	Yes	No	NA	NA	NA	12/1995	NA	NA	24
Virginia	Appalachian Power Co.	AEP	C-PUE-960063	Electric	Vertically Integrated	9/28/1994	15.7	9.28	10.50	39.93	NA	5/24/1996	Fully Litigated	0.0	No	Yes	NA	NA	NA	09/1994	NA	Average	20
Missouri	Kansas City Power & Light	EVRG	C-ECI-94-199	Electric	Vertically Integrated	5/28/1996	(20.0)	NA	10.5	NA	NA	7/3/1996	Settled	(20.0)	Yes	No	NA	NA	NA	NA	NA	NA	1
Oregon	PacifiCorp	BRK-A	D-UE-94	Electric	Vertically Integrated	9/1/1995	124.9	9.83	10.50	46.60	NA	7/10/1996	Settled	26.8	No	No	NA	NA	NA	06/1997	NA	Average	10
Pennsylvania	UGI Utilities Inc.	UGI	C-R-95453/4	Electric	Vertically Integrated	1/26/1996	6.2	10.18	10.50	46.67	NA	7/18/1996	Settled	3.1	No	No	NA	NA	NA	09/1995	NA	Year-end	5
Louisiana	Entergy Gulf States La LLC	ETR	D-U-21485	Electric	Vertically Integrated	5/31/1995	19.0	9.42	10.50	37.28	NA	9/24/1996	Fully Litigated	(20.0)	No	No	NA	NA	NA	12/1994	NA	Average	16
Louisiana	Entergy Louisiana LLC	ETR	D-U-20925-A&B	Electric	Vertically Integrated	4/15/1996	(12.0)	NA	10.5	NA	NA	11/12/1996	Fully Litigated	(16.5)	No	Yes	NA	NA	NA	12/1995	NA	Average	7
Colorado	Public Service Co. of CO	XEL	D-95A-531EG	Electric	Vertically Integrated	11/9/1995	0.0	NA	10.5	NA	NA	11/26/1996	Settled	(18.0)	Yes	No	NA	NA	NA	06/1995	NA	Year-end	12
West Virginia	Appalachian Power Co.	AEP	C-96-0458-E-GI	Electric	Vertically Integrated	6/8/1996	34.2	9.67	10.50	37.11	NA	12/27/1996	Settled	(5.0)	No	No	NA	NA	NA	12/1995	NA	Average	6
Kansas	Kansas Gas and Electric Co.	WR	D-193,306-U	Electric	Vertically Integrated	8/17/1995	12.0	7.85	10.50	37.10	NA	1/15/1997	Fully Litigated	(65.0)	Yes	No	NA	NA	NA	03/1995	NA	Year-end	17
Kansas	Westar Energy Inc.	EVRG	D-193,307-U	Electric	Vertically Integrated	8/17/1995	9.0	7.89	10.50	37.30	NA	1/15/1997	Fully Litigated	(10.0)	No	No	NA	NA	NA	03/1995	NA	Year-end	17
Oklahoma	Oklahoma Gas and Electric Co.	OGE	Cs-PUD-960000116	Electric	Vertically Integrated	6/17/1996	(14.2)	10.15	10.50	51.08	NA	2/11/1997	Settled	(55.7)	Yes	No	NA	NA	NA	NA	NA	NA	7
Iowa	MidAmerican Energy Co.	BRK-A	D-RPU-96-8	Electric	Vertically Integrated	6/4/1996	(21.0)	NA	10.5	NA	NA	6/27/1997	Settled	(23.7)	No	Yes	NA	NA	NA	NA	NA	Average	12
Missouri	Empire District Electric Co.	AQN	C-ER-97-81	Electric	Vertically Integrated	8/30/1996	23.4	10.35	10.50	48.40	NA	7/16/1997	Settled	13.6	No	No	NA	NA	NA	NA	NA	NA	10
Louisiana	Entergy Louisiana LLC	ETR	D-U-20925-D	Electric	Vertically Integrated	5/30/1997	(36.7)	NA	10.5	NA	NA	9/24/1997	Fully Litigated	(59.0)	No	No	NA	NA	NA	12/1996	NA	Average	3
Oklahoma	Public Service Co. of OK	AEP	Cs-PUD-960000-214	Electric	Vertically Integrated	7/19/1996	9.3	9.82	10.50	NA	NA	10/20/1997	Settled	(35.9)	No	No	NA	NA	NA	06/1996	NA	Year-end	15
Maryland	Potomac Electric Power Co.	EXC	C-8773	Electric	Vertically Integrated	8/20/1997	64.5	9.52	10.50	42.70	NA	11/20/1997	Settled	24.0	No	No	NA	NA	NA	09/1997	NA	Average	3
Kansas	Kansas City Power & Light	EVRG	D-97-KCPE-661-RTS	Electric	Vertically Integrated	8/18/1997	1.8	9.43	10.50	51.62	NA	1/7/1998	Settled	(14.2)	No	No	NA	NA	NA	09/1996	NA	Year-end	4
Louisiana	Entergy Gulf States La LLC	ETR	D-U-22092	Electric	Vertically Integrated	5/31/1996	(5.3)	NA	10.5	NA	NA	9/10/1998	Fully Litigated	(36.6)	No	No	NA	NA	NA	12/1995	NA	Average	27
New Mexico	El Paso Electric Co.	EE	C-2722	Electric	Vertically Integrated	3/13/1997	8.6	9.14	10.50	39.44	NA	9/24/1998	Settled	(4.6)	No	No	NA	NA	NA	09/1996	NA	Year-end	19
Louisiana	Entergy New Orleans LLC	ETR	D-UD-97-1 (elec.)	Electric	Vertically Integrated	2/6/1997	NA	NA	10.5	NA	NA	11/5/1998	Settled	(43.4)	Yes	No	NA	NA	NA	12/1996	NA	Average	21
Maryland	Potomac Electric Power Co.	EXC	C-8791	Electric	Vertically Integrated	6/5/1998	56.3	9.23	10.50	42.47	NA	11/30/1998	Settled	19.0	No	No	NA	NA	NA	06/1998	NA	NA	5
New Mexico	Southwestern Public Service Co.	XEL	C-2798	Electric	Vertically Integrated	5/5/1998	(1.7)	9.56	10.50	49.20	NA	11/30/1998	Settled	(6.0)	No	No	NA	NA	NA	12/1997	NA	Year-end	6
California	San Diego Gas & Electric Co.	SRE	AP-9801014 De-9812038 (elec.)	Electric	Vertically Integrated	1/16/1998	35.0	NA	10.5	NA	NA	12/17/1998	Settled	(14.2)	Yes	No	NA	NA	NA	12/1999	NA	NA	11
Georgia	Georgia Power Co.	SO	D-9355-U	Electric	Vertically Integrated	6/4/1998	(50.0)	NA	10.5	NA	NA	12/18/1998	Settled	(295.0)	Yes	No	NA	NA	NA	NA	NA	NA	6
Michigan	DTE Electric Co.	DTE	C-U-11726	Electric	Vertically Integrated	7/1/1998	0.0	NA	10.5	NA	NA	12/28/1998	Fully Litigated	(93.8)	Yes	No	NA	NA	NA	NA	NA	NA	6
Virginia	Appalachian Power Co.	AEP	C-PUE-960301	Electric	Vertically Integrated	6/13/1997	30.5	9.79	10.50	39.33	NA	2/19/1999	Settled	(6.0)	No	No	NA	NA	NA	12/1996	NA	Year-end	20
Missouri	Kansas City Power & Light	EVRG	C-ER-99-313	Electric	Vertically Integrated	1/26/1999	0.0	NA	10.5	NA	NA	4/13/1999	Settled	(15.0)	No	No	NA	NA	NA	NA	NA	NA	2
Texas	Entergy Texas Inc.	ETR	D-20150	Electric	Vertically Integrated	11/30/1998	90.0	9.81	10.50	46.49	NA	6/29/1999	Settled	38.0	No	Yes	9.67	NA	NA	06/1998	NA	Year-end	7
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-99-247	Electric	Vertically Integrated	12/1/1998	6.1	10.70	10.50	58.40	NA	8/17/1999	Settled	(2.5)	No	No	NA	NA	NA	NA	NA	NA	8
Colorado	Public Service Co. of CO	XEL	D-99A-377EG	Electric	Vertically Integrated	7/28/1999	NA	NA	10.5	NA	NA	2/16/2000	Settled	(11.0)	No	No	NA	NA	NA	NA	NA	NA	6
Louisiana	Entergy Gulf States La LLC	ETR	D-U-22491	Electric	Vertically Integrated	5/31/1997	12.1	NA	10.50	NA	NA	3/22/2000	Settled	0.0	No	No	NA	NA	NA	12/1996	NA	Average	34
West Virginia	Appalachian Power Co.	AEP	C-99-0459-E-GI	Electric	Vertically Integrated	5/11/1999	50.3	9.49	10.50	39.55	NA	6/2/2000	Settled	0.0	No	No	NA	NA	NA	12/1999	NA	Average	12
Washington	PacifiCorp	BRK-A	D-UE-99-1832	Electric	Vertically Integrated	11/24/1999	25.8	9.10	10.50	48.80	NA	8/9/2000	Settled	13.1	Yes	No	NA	NA	NA	NA	NA	NA	8
Oregon	PacifiCorp	BRK-A	D-UE-111	Electric	Vertically Integrated	11/5/1999	61.8	9.10	10.50	48.80	NA	9/25/2000	Settled	13.6	No	No	8.71	NA	NA	12/1998	NA	Average	10
Iowa	MidAmerican Energy Co.	BRK-A	D-RPU-01-5	Electric	Vertically Integrated	6/11/2001	50.5	9.91	10.50	53.41	NA	12/21/2001	Settled	0.0	No	No	NA	NA	NA	12/2000	NA	Average	6
Montana	NorthWestern Corp.	NWE	D-D97.7.90	Electric	Distribution	1/6/2000	(16.7)	NA	10.5	NA	NA	1/31/2002	Settled	(16.7)	No	Yes	NA	NA	NA	NA	NA	NA	25
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-2001-672,EC-2002-265	Electric	Vertically Integrated	6/8/2001	49.4	10.15	10.50	48.00	NA	2/21/2002	Settled	(4.3)	No	No	NA	NA	NA	NA	NA	NA	8
New York	NY State Electric & Gas Corp.	IBE	C-01-E-0359	Electric	Distribution	3/14/2001	0.0	NA	10.5	NA	NA	2/27/2002	Settled	(205.0)	Yes	No	NA	NA	NA	NA	NA	NA	11
Missouri	Union Electric Co.	AEE	C-EC-2002-1	Electric	Vertically Integrated	7/2/2001	148.0	10.14	10.50	59.08	NA	7/25/2002	Settled	(110.0)	No	No	NA	NA	NA	NA	NA	NA	12
Indiana	Northern IN Public Serv. Co.	NI	Ca-41746	Electric	Vertically Integrated	1/24/2001	NA	NA	10.5	NA	NA	9/23/2002	Settled	NA	No	No	NA	NA	NA	NA	NA	NA	20
Missouri	Empire District Electric Co.	AQN	C-ER-2002-425	Electric	Vertically Integrated	3/8/2002	19.8	9.94	10.50	47.50	NA	11/14/2002	Settled	11.0	No	No	NA	NA	NA	NA	NA	NA	8
New Mexico	Public Service Co. of NM	PNM	C-3137	Electric	Vertically Integrated	10/10/2002	(35.2)	NA	10.5	NA	NA	1/28/2003	Settled	(35.2)	Yes	No	NA	NA	NA	NA	NA	NA	3
Louisiana	Entergy New Orleans LLC	ETR	D-UD-01-04 (elec.)	Electric	Vertically Integrated	6/1/2001	28.9	9.72	10.50	45.00	NA	5/15/2003	Settled	16.4	No	No	NA	NA	NA	NA	NA	NA	23
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-2004-0034 (MPS)	Electric	Vertically Integrated	7/3/2003	65.0	9.59	10.50	47.50	725.00	4/13/2004	Settled	14.5	No	No	NA	NA	NA	NA	NA	NA	9
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-2004-0034 (L&P)	Electric	Vertically Integrated	7/3/2003	14.6	9.85	10.50	47.50	197.00	4/13/2004	Settled	3.3	No	No	NA	NA	NA	NA	NA	NA	9
Wisconsin	Wisconsin Electric Power Co.	WEC	D-05-UR-101 (elec. 2003)	Electric	Vertically Integrated	7/2/2003	63.5	NA	10.5	NA	NA	5/5/2004	Fully Litigated	59.0	No	No	NA	NA	NA	12/2004	NA	Average	10
New York	Rochester Gas & Electric Corp.	IBE	C-03-E-0765	Electric	Distribution	5/16/2003	80.3	8.53	10.50	46.41	1,106.30	5/20/2004	Settled	7.4	Yes	No	NA	NA	NA	04/2005	NA	Average	12
New Hampshire	Public Service Co. of NH	ES	D-DE-03-200	Electric	Distribution	12/28/2003	21.4	7.74	10.50	47.81	498.10	9/2/2004	Settled	13.5	Yes	No	NA	NA	NA	NA	NA	NA	8
Texas	Entergy Texas Inc.	ETR	D-30123	Electric	Vertically Integrated	8/25/2004	42.6	8.57	10.50	46.96	1,476.00	9/30/2004	Fully Litigated	0.0	No	No	NA	NA	NA	NA	NA	NA	1
Washington	PacifiCorp	BRK-A	D-UE-03-2065	Electric	Vertically Integrated	12/05/2003	26.7	8.74	10.50	47.08	596.30	10/27/2004	Settled	15.0	No	No	8.39	NA	NA	NA	NA	NA	10
California	San Diego Gas & Electric Co.	SRE	AP-0212028 De-0412015 (elec)	Electric	Vertically Integrated	12/20/2002	58.9	NA	10.5	NA	NA	12/8/2004	Settled	(6.2)	No	No	NA	NA	NA	12/2004	NA	NA	23
North Carolina	Virginia Electric & Power Co.	D	E-22,SUB412	Electric	Vertically Integrated	5/13/2004	10.8	8.57	10.50	50.39	501.20	3/18/2005	Settled	(12.0)	No	No	NA	NA	NA	12/2003	NA	NA	10
Michigan	Upper Peninsula Power Co.		C-U-14410	Electric	Vertically Integrated	2/4/2005	5.7	8.28	10.50	47.39	100.80	4/28/2005	Settled	0.0	No	No	NA	NA	NA	NA	NA	NA	2
Oklahoma	Public Service Co. of OK	AEP	Cs-PUD-200300076	Electric	Vertically Integrated	10/31/2003	40.9	9.43	10.50	48.45	1,060.60	5/2/2005	Settled	(6.9)	No	No	NA	NA	NA	12/2003	NA	Year-end	18
Wisconsin	Wisconsin Electric Power Co.	WEC	D-05-UR-101 (elec. 2004)	Electric	Vertically Integrated	5/10/2004	84.8	NA	10.5	NA	NA	5/18/2005	Fully Litigated	59.7	No	No	NA	NA	NA	12/2005	NA	Average	12
Idaho	PacifiCorp	BRK-A	C-PAC-E-05-1	Electric	Vertically Integrated	1/14/2005	16.9	8.66	10.50	47.80	407.80	7/22/2005	Settled	5.8	No	No	NA	NA	NA	NA	NA	NA	6
Kansas	Empire District Electric Co.	AQN	D-05-EPDE-980-RTS	Electric	Vertically Integrated	4/29/2005	4.2	8.14	10.50	42.44	50.90	12/9/2005	Settled	2.2	No	No	NA	NA	NA	NA	NA	NA	7
Massachusetts	NSTAR Electric Co.	ES	DTE-05-85 (elec.)	Electric	Distribution	12/6/2005	87.4	NA	10.5	NA	NA	12/30/2005	Settled	30.0	No	No	NA	NA	NA	NA	NA	NA	0
Wisconsin	Wisconsin Electric Power Co.	WEC	D-05-UR-102 (WEP-EL)	Electric	Vertically Integrated	7/1/2005	256.4	NA	10.5	NA	NA	1/25/2006	Fully Litigated	229.7	No	No	NA	NA	NA	12/2006	NA	NA	6
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-2005-0436 (MPS)	Electric	Vertically Integrated	5/24/2005	67.3	9.01	10.50	48.20	833.60	2/23/2006	Settled	22.4	No	No	NA	NA	NA	NA	NA	NA	9

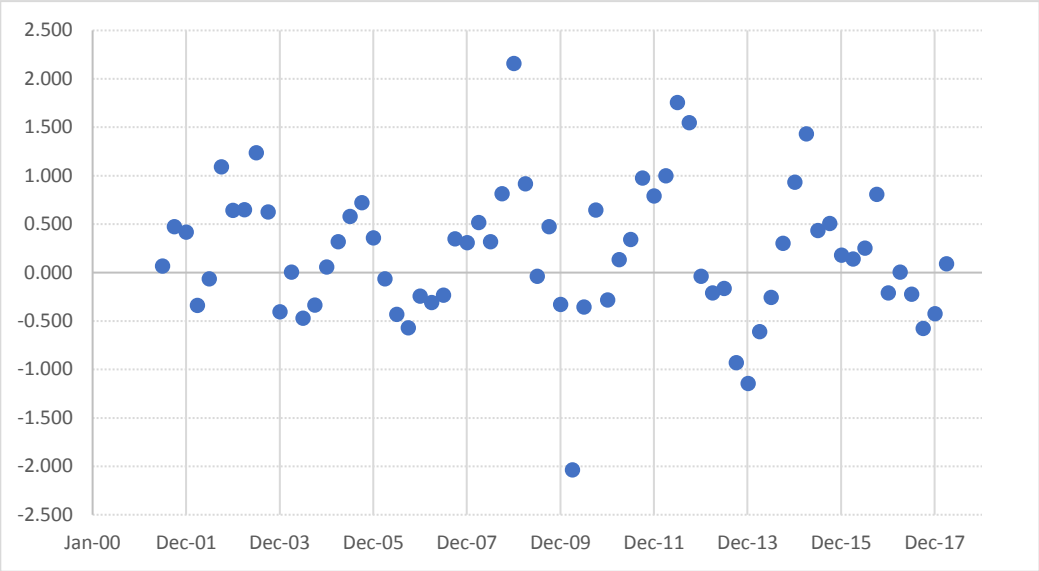
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-2005-0436 (L&P)	Electric	Vertically Integrated	5/24/2005	7.0	9.67	10.50	48.20	187.60	2/23/2006	Settled	3.9	No	No	NA	NA	NA	NA	NA	NA	9
Kentucky	Kentucky Power Co.	AEP	C-2005-00341	Electric	Vertically Integrated	9/26/2005	64.8	7.84	10.50	39.54	858.40	3/14/2006	Settled	41.0	No	No	NA	NA	NA	NA	NA	NA	5
Wyoming	PacifiCorp	BRK.A	D-20000-230-ER-05	Electric	Vertically Integrated	10/14/2005	40.2	8.74	10.50	50.80	976.20	3/24/2006	Settled	25.0	Yes	No	NA	NA	NA	NA	NA	NA	5
Idaho	Idaho Power Co.	IDA	C-IPC-E-05-28	Electric	Vertically Integrated	10/28/2005	43.9	8.42	10.50	49.46	1,654.30	5/12/2006	Settled	18.1	No	No	8.10	NA	NA	12/2005	NA	NA	6
Michigan	DTE Electric Co.	DTE	C-U-14838	Electric	Vertically Integrated	3/23/2006	45.3	7.36	10.50	41.59	7,906.80	8/31/2006	Settled	(78.8)	Yes	No	NA	NA	NA	12/2005	NA	NA	5
Texas	CenterPoint Energy Houston	CNP	D-32093	Electric	Distribution	4/14/2006	93.3	8.97	10.50	50.00	3,417.10	9/5/2006	Settled	(57.9)	No	No	NA	NA	NA	12/2005	NA	NA	4
Pennsylvania	Duquesne Light Co.		C-R-00061346	Electric	Distribution	4/7/2006	163.0	NA	10.50	48.00	1,200.00	11/30/2006	Settled	117.0	No	No	NA	NA	45.00	12/2006	NA	NA	7
Kansas	Kansas City Power & Light	EVRG	D-06-KCPE-828-RTS	Electric	Vertically Integrated	1/31/2006	42.3	9.01	10.50	53.81	1,015.00	12/4/2006	Settled	29.0	No	No	NA	NA	NA	NA	NA	NA	10
Massachusetts	Western Massachusetts	ES	DTE-06-55	Electric	Distribution	10/20/2006	4.0	NA	10.5	NA	NA	12/14/2006	Settled	4.0	Yes	No	NA	NA	NA	NA	NA	NA	1
Kentucky	Duke Energy Kentucky Inc.	DUK	C-2006-00172	Electric	Vertically Integrated	5/31/2006	66.6	8.26	10.50	50.88	591.10	12/21/2006	Settled	49.0	No	No	NA	NA	NA	NA	NA	NA	6
South Dakota	Black Hills Power Inc.	BKH	D-EL06-019	Electric	Vertically Integrated	6/30/2006	9.6	9.83	10.50	54.26	286.04	12/28/2006	Settled	7.9	No	No	NA	NA	NA	NA	NA	NA	6
Texas	AEP Texas North Co	AEP	D-33310	Electric	Distribution	11/9/2006	25.0	7.97	10.50	40.00	459.90	5/24/2007	Settled	13.7	No	No	NA	NA	NA	06/2006	NA	NA	6
New Mexico	El Paso Electric Co.	EE	C-06-00258-UT	Electric	Vertically Integrated	6/30/2006	31.7	8.35	10.50	49.10	300.00	7/3/2007	Settled	5.5	No	No	NA	NA	NA	12/2005	NA	Year-end	12
Texas	Southwestern Public Service Co.	XEL	D-32766	Electric	Vertically Integrated	5/31/2006	66.3	9.15	10.50	51.13	968.56	7/27/2007	Settled	23.0	No	Yes	NA	NA	NA	09/2005	NA	NA	14
Kansas	Kansas City Power & Light	EVRG	D-07-KCPE-905-RTS	Electric	Vertically Integrated	3/1/2007	47.1	8.83	10.50	53.43	1,107.82	11/20/2007	Settled	28.0	No	No	NA	NA	NA	NA	NA	NA	8
Pennsylvania	PPL Electric Utilities Corp.	PPL	C-R-00072155	Electric	Distribution	3/29/2007	63.6	8.36	10.50	43.13	2,024.00	12/6/2007	Settled	55.0	No	No	NA	NA	NA	12/2007	NA	NA	8
Idaho	Idaho Power Co.	IDA	C-IPC-E-07-08	Electric	Vertically Integrated	6/8/2007	63.9	8.56	10.50	50.26	1,883.00	2/28/2008	Settled	32.1	No	No	8.10	NA	NA	NA	NA	NA	8
Texas	Oncor Electric Delivery Co.	SRE	D-34040	Electric	Distribution	8/28/2007	318.0	8.55	10.50	44.15	6,880.00	6/30/2008	Settled	0.0	No	No	NA	NA	NA	12/2006	NA	NA	10
Montana	NorthWestern Corp.	NWE	D-D2007.7.82 (elec)	Electric	Distribution	7/31/2007	31.4	8.98	10.50	51.46	667.44	7/1/2008	Settled	10.0	No	Yes	NA	NA	NA	NA	NA	NA	11
Washington	PacifiCorp	BRK.A	D-UE-08-0220	Electric	Vertically Integrated	2/6/2008	35.0	8.47	10.50	50.10	624.90	10/8/2008	Settled	20.4	No	No	8.06	NA	NA	NA	NA	NA	8
Wisconsin	Wisconsin Power and Light Co.	LNT	6680-UR-116 (elec)	Electric	Vertically Integrated	2/22/2008	93.3	10.08	10.50	55.40	1,356.90	12/30/2008	Settled	0.0	No	No	NA	NA	NA	12/2009	NA	NA	10
Wisconsin	Wisconsin Public Service Corp.	WEC	D-6690-UR-119 (elec)	Electric	Vertically Integrated	4/1/2008	68.4	9.29	10.50	58.11	1,241.90	12/30/2008	Settled	48.0	No	No	NA	NA	53.41	12/2009	NA	NA	9
Kansas	Kansas Gas and Electric Co.	WR	D-08-WSEE-1041-RTS (KG&E)	Electric	Vertically Integrated	5/28/2008	87.6	8.69	10.50	48.46	1,517.29	1/21/2009	Settled	65.0	No	No	NA	NA	NA	NA	NA	NA	7
Kansas	Westar Energy Inc.	EVRG	D-08-WSEE-1041-RTS (WR)	Electric	Vertically Integrated	5/28/2008	90.0	8.68	10.50	48.46	1,641.05	1/21/2009	Settled	65.0	No	No	NA	NA	NA	NA	NA	NA	7
Kentucky	Kentucky Utilities Co.	PPL	C-2008-00251	Electric	Vertically Integrated	7/29/2008	22.2	7.77	10.50	52.63	2,216.90	2/5/2009	Settled	(8.9)	No	No	NA	NA	NA	NA	NA	NA	6
Kentucky	Louisville Gas & Electric Co.	PPL	C-2008-00252 (elec.)	Electric	Vertically Integrated	7/29/2008	15.1	8.30	10.50	52.48	1,795.20	2/5/2009	Settled	(13.2)	No	No	NA	NA	NA	NA	NA	NA	6
Texas	Entergy Texas Inc.	ETR	D-34800	Electric	Vertically Integrated	9/26/2007	107.5	8.67	10.50	48.69	1,746.14	3/11/2009	Settled	30.5	No	Yes	NA	NA	NA	03/2007	NA	NA	17
Idaho	PacifiCorp	BRK.A	C-PAC-E-08-07	Electric	Vertically Integrated	9/19/2008	19.4	8.49	10.50	50.40	565.41	4/16/2009	Settled	4.4	No	No	NA	NA	NA	NA	NA	NA	6
Wyoming	PacifiCorp	BRK.A	D-20000-332-ER-08	Electric	Vertically Integrated	7/24/2008	28.7	8.53	10.50	51.90	1,489.96	5/20/2009	Settled	18.0	No	No	NA	NA	NA	NA	NA	NA	10
Colorado	Public Service Co. of CO	XEL	D-08S-520E	Electric	Vertically Integrated	11/14/2008	159.3	9.01	10.50	58.08	4,122.19	5/27/2009	Settled	112.2	No	No	NA	NA	NA	NA	NA	NA	6
Texas	Southwestern Public Service Co.	XEL	D-35763	Electric	Vertically Integrated	6/12/2008	94.4	8.85	10.50	51.01	989.40	6/2/2009	Settled	57.4	No	Yes	NA	NA	NA	12/2007	NA	NA	11
Missouri	Kansas City Power & Light	EVRG	C-ER-2009-0089	Electric	Vertically Integrated	9/5/2008	101.5	8.69	10.50	53.82	1,501.35	6/10/2009	Settled	95.0	No	No	NA	NA	NA	12/2007	NA	Year-end	9
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-2009-0090 (L&P)	Electric	Vertically Integrated	9/5/2008	17.1	9.29	10.50	53.82	305.03	6/10/2009	Settled	15.0	No	No	NA	NA	NA	12/2007	NA	Year-end	9
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-2009-0090 (MPS)	Electric	Vertically Integrated	9/5/2008	66.0	8.93	10.50	53.82	1,202.23	6/10/2009	Settled	48.0	No	No	NA	NA	NA	12/2007	NA	Year-end	9
Kansas	Kansas City Power & Light	EVRG	D-09-KCPE-246-RTS	Electric	Vertically Integrated	9/5/2008	71.6	8.75	10.50	55.39	1,254.15	6/24/2009	Settled	59.0	No	No	NA	NA	NA	12/2007	NA	Year-end	9
New Mexico	Southwestern Public Service Co.	XEL	C-08-00354-UT	Electric	Vertically Integrated	12/18/2008	24.6	9.50	10.50	50.00	321.00	7/14/2009	Settled	14.2	No	Yes	NA	NA	NA	NA	NA	NA	6
Oklahoma	Oklahoma Gas and Electric Co.	OGE	Cs-PUD200800398	Electric	Vertically Integrated	2/27/2009	110.3	9.64	10.50	54.14	2,862.74	7/24/2009	Settled	48.3	No	No	NA	NA	NA	09/2008	NA	Year-end	4
Texas	Texas-New Mexico Power Co.	PNM	D-36025	Electric	Distribution	8/29/2008	24.4	10.16	10.50	40.00	430.10	8/21/2009	Settled	12.7	No	No	NA	NA	NA	03/2008	NA	NA	11
New Mexico	El Paso Electric Co.	EE	C-09-00171-UT	Electric	Vertically Integrated	5/29/2009	12.7	9.06	10.50	49.35	339.27	12/16/2009	Settled	5.5	No	No	NA	NA	NA	NA	339.27	Year-end	6
Washington	PacifiCorp	BRK.A	D-UE-090205	Electric	Vertically Integrated	2/6/2009	38.5	8.51	10.50	50.10	737.86	12/16/2009	Settled	13.5	No	No	8.06	NA	NA	NA	NA	NA	10
South Dakota	Northern States Power Co. - MN	XEL	D-EL09-009	Electric	Vertically Integrated	6/30/2009	18.6	9.02	10.50	51.63	282.64	1/5/2010	Settled	10.9	No	No	8.32	NA	NA	NA	NA	NA	6
Texas	Southwestern Electric Power Co	AEP	D-37364	Electric	Vertically Integrated	8/28/2009	81.9	8.78	10.50	50.65	668.74	4/16/2010	Settled	25.0	No	No	NA	NA	NA	03/2009	NA	NA	7
Wyoming	PacifiCorp	BRK.A	D-20000-352-ER-09	Electric	Vertically Integrated	10/2/2009	62.0	8.63	10.50	52.80	1,724.57	5/14/2010	Settled	35.5	Yes	No	8.33	NA	NA	NA	1,724.57	NA	7
Kansas	Empire District Electric Co.	AQN	D-10-EPDE-314-RTS	Electric	Vertically Integrated	11/4/2009	5.2	8.80	10.50	48.29	69.18	6/23/2010	Settled	2.8	No	No	NA	NA	NA	NA	NA	NA	7
West Virginia	Monongahela Power Co.	FE	C-09-1352-E-42T	Electric	Vertically Integrated	6/12/2009	122.1	9.31	10.50	41.60	1,545.48	6/25/2010	Settled	60.0	Yes	No	8.71	NA	NA	12/2008	1,269.61	NA	10
South Dakota	Black Hills Power Inc.	BKH	D-EL09-018	Electric	Vertically Integrated	9/29/2009	38.8	9.27	10.50	52.00	363.43	7/7/2010	Settled	22.0	Yes	Yes	8.26	NA	NA	06/2009	380.53	Average	9
Kentucky	Kentucky Utilities Co.	PPL	C-2009-00549	Electric	Vertically Integrated	1/29/2010	135.3	8.32	10.50	53.85	3,054.54	7/30/2010	Settled	98.0	No	No	NA	NA	NA	10/2009	NA	Year-end	6
Kentucky	Louisville Gas & Electric Co.	PPL	C-2009-00549 (elec.)	Electric	Vertically Integrated	1/29/2010	94.6	8.32	10.50	53.86	1,805.79	7/30/2010	Settled	74.0	No	No	NA	NA	NA	10/2009	NA	Year-end	6
Texas	El Paso Electric Co.	EE	D-37690	Electric	Vertically Integrated	12/9/2009	50.8	9.22	10.50	51.27	969.24	7/30/2010	Settled	17.2	No	Yes	NA	NA	NA	06/2009	NA	NA	7
Missouri	Empire District Electric Co.	AQN	C-ER-2010-0130	Electric	Vertically Integrated	10/29/2009	68.2	8.93	10.50	48.00	1,077.38	8/18/2010	Settled	46.8	No	No	NA	NA	NA	06/2009	NA	Year-end	9
Idaho	Avista Corp.	AVA	C-AVU-E-10-01	Electric	Vertically Integrated	3/23/2010	32.1	8.55	10.50	50.00	607.96	9/21/2010	Settled	21.3	No	No	NA	NA	NA	12/2009	NA	NA	6
Pennsylvania	PECO Energy Co.	EXC	D-R-2010-2161575	Electric	Distribution	3/31/2010	316.4	8.95	10.50	53.18	3,236.00	12/16/2010	Settled	225.0	No	No	NA	NA	NA	12/2010	NA	NA	8
Pennsylvania	PPL Electric Utilities Corp.	PPL	D-R-2010-2161694	Electric	Distribution	3/31/2010	114.7	9.11	10.50	48.37	2,244.96	12/16/2010	Settled	77.5	No	No	NA	NA	NA	12/2010	NA	NA	8
Pennsylvania	Duquesne Light Co.		D-R-2010-2179522	Electric	Distribution	7/23/2010	87.3	8.78	10.50	52.42	1,439.93	2/24/2011	Settled	45.7	No	No	NA	NA	NA	03/2011	NA	NA	7
Texas	Southwestern Public Service Co.	XEL	D-38147	Electric	Vertically Integrated	5/17/2010	55.4	9.24	10.50	51.00	941.08	3/25/2011	Settled	52.5	Yes	Yes	NA	NA	NA	12/2009	NA	NA	10
California	Pacific Gas and Electric Co.	PCG	AP-09-12-020 (elec)	Electric	Vertically Integrated	12/21/2009	856.0	NA	10.5	NA	14,783.00	5/13/2011	Settled	403.0	Yes	No	NA	NA	NA	12/2011	14,174.95	Average	16
Missouri	Empire District Electric Co.	AQN	C-ER-2011-0004	Electric	Vertically Integrated	9/28/2010	36.5	8.82	10.50	50.95	1,067.91	6/1/2011	Settled	18.7	No	No	NA	NA	NA	06/2009	NA	NA	8
Maryland	Delmarva Power & Light Co.	EXC	C-9249	Electric	Distribution	12/21/2010	18.3	8.08	10.50	49.81	344.57	7/8/2011	Settled	12.2	No	No	NA	NA	NA	12/2010	NA	NA	6
Montana	MDU Resources Group Inc.	MDU	D-D2010.8.82	Electric	Vertically Integrated	8/11/2010	4.9	8.78	10.50	51.15	87.25	8/2/2011	Settled	2.6	No	Yes	NA	NA	NA	NA	NA	NA	11
Idaho	Avista Corp.	AVA	C-AVU-E-11-01	Electric	Vertically Integrated	7/5/2011	9.0	8.49	10.50	50.15	627.00	9/30/2011	Settled	2.8	No	No	NA	NA	NA	12/2010	NA	NA	2
Wisconsin	Wisconsin Electric Power Co.	WEC	D-5-UR-105 (WEP-EL)	Electric	Vertically Integrated	5/23/2011	0.0	NA	10.5	NA	NA	10/6/2011	Fully Litigated	0.0	No	No	NA	NA	NA	12/2012	NA	NA	4
Washington	Avista Corp.	AVA	D-UE-110876	Electric	Vertically Integrated	5/16/2011	38.3	8.23	10.50	48.04	1,127.81	12/16/2011	Settled	20.0	No	No	NA	NA	NA	NA	NA	NA	7
Texas	Southwestern Electric Power Co.	AEP	D-39708	Electric	Vertically Integrated	8/31/2011	60.3	8.21	10.50	49.70	372.90	12/21/2011	Fully Litigated	NA	No	No	NA	NA	NA	NA	NA	NA	3
New Mexico	Southwestern Public Service Co.	XEL	C-10-00395-UT	Electric	Vertically Integrated	2/28/2011	19.9	9.04	10.50	51.11	390.28	12/28/2011	Settled	13.5	No	No	NA	NA	NA	NA	NA	NA	10
Idaho	Idaho Power Co.	IDA	C-IPC-E-11-08	Electric	Vertically Integrated	6/1/2011	82.6	8.17	10.50	51.20	2,355.91	12/30/2011	Settled	34.0	No	No	7.86	NA	NA	12/2011	2,355.91	NA	7
Illinois	Ameren Illinois	AEE	D-11-0279 (elec)	Electric	Distribution	2/18/2011	39.0	9.44	10.50	52.87	2,012.81	1/5/2012	Fully Litigated	NA	No	No	NA	NA	NA	NA	NA	NA	10
Idaho	PacifiCorp	BRK.A	C-PAC-E-11-12	Electric	Vertically Integrated	5/27/2011	32.7	8.25	10.50	52.30	745.70	1/10/2012	Settled	34.0	Yes	No	NA	NA	NA	12/2010	NA	NA	7
Florida	Duke Energy Florida LLC	DUK	D-120022-EI	Electric	Vertically Integrated	1/20/2012	150.0	NA	10.5	NA	NA	2/22/2012	Settled	150.0	No	No	NA	NA	NA	NA	NA	NA	1
Washington	PacifiCorp	BRK.A	D-UE-111190	Electric	Vertically Integrated	7/1/2011	12.9	7.74	10.5	NA	750.50	3/30/2012	Settled	4.5	No	No	7.74	NA	NA	12/2010	NA	NA	9
Kansas	Westar Energy Inc.	EVRG	D-12-WSEE-112-RTS	Electric	Vertically Integrated	8/25/2011	90.8	8.68	10.50	51.62	3,399.27	4/18/2012	Settled	50.0	No	No	NA	NA	NA	03/2011	NA	NA	7
Texas	El Paso Electric Co.	EE	D-40094	Electric	Vertically Integrated	2/1/2012	26.3	8.94	10.50	53.38	1,126.22	5/18/2012	Settled	(15.0)	No	Yes	NA	NA	NA	09/2011	NA	NA	3
California	Southern California Edison Co.	EIX	AP-10-11-015	Electric	Vertically Integrated	11/23/2010	809.0	NA	10.5	NA	16,224.21	11/29/2012	Fully Litigated	271.9	Yes	No	NA	NA	NA	12/2012	15,072.22	Average	24
Missouri	Empire District Electric Co.	AQN	C-ER-2012-0345	Electric	Vertically Integrated	7/6/2012	30.7	8.32	10.50	51.00	1,005.67	2/27/2013	Settled	27.5	No	No	NA	NA	NA	03/2012	NA	NA	7
Hawaii	Hawaii Electric Light Co.	HE	D-2012-0099	Electric	Vertically Integrated	8/16/2012	19.8	8.30	10.50	57.05	455.00	3/19/2013	Settled	NA	No	No	NA	NA	NA	NA	NA	NA	7
South Dakota	Northern States Power Co. - MN	XEL	D-EL12-046	Electric	Vertically Integrated	6/29/2012	19.4	8.51	10.50	52.89	367.51	4/18/2013	Settled	11.6	No	Yes	7.78	NA	NA	12/2011	351.74	Average	9
California	San Diego Gas & Electric Co.	SRE	AP-10-12-005 (elec)	Electric	Vertically Integrated	12/15/2010	201.8	NA	10.5	NA	3,743.25	5/9/2013	Fully Litigated	115.2	Yes	No	NA	NA	NA	12/2012	3,574.12	Average	29
Texas	Southwestern Public Service Co.	XEL	D-40824	Electric	Vertically Integrated	11/15/2012	90.2	8.62	10.50	52.00	1,150.58	6/6/2013	Settled	50.8	Yes	Yes	NA	NA	NA	06/2012	NA	NA	6
Wisconsin	Madison Gas and Electric Co.	MGEE	D-3270-UR-119 (Elec)	Electric	Vertically Integrated	4/15/2013	0.0	NA	10.5	NA	NA	7/26/2013	Settled	0.0	No	No	NA	NA	NA	12/2014	NA	NA	3
Maryland	Delmarva Power & Light Co.	EXC	C-9317	Electric	Distribution	3/29/2013	22.6	7.67	10.50	49.58	507.86	9/3/2013	Settled	15.0	No	No	NA	NA	NA	12/2012	NA	NA	5
South Dakota	Black Hills Power Inc.	BKH	D-EL12-061	Electric	Vertically Integrated	12/17/2012	13.7	8.54	10.50	53.17	438.29	9/17/2013	Settled	8.8	No	Yes	7.93	NA	NA	NA	NA	NA	9
Idaho	PacifiCorp	BRK.A	C-PAC-E-13-04	Electric	Vertically Integrated	6/3/2013	2.0	NA	10.5	NA	NA	10/24/2013	Settled	2.0	No	No	NA	NA	NA	NA	NA	NA	4
Kentucky	Kentucky Power Co.	AEP	C-2013-00197	Electric	Vertically Integrated	6/28/2013	114.0	8.08	10.50	45.80	1,584.18	11/22/2013	Fully Litigated	NA	No	No	NA	NA	NA	NA	NA	NA	4
Virginia	Kentucky Utilities Co.	PPL	PUE-2013-00013	Electric	Vertically Integrated	4/1/2013	6.5	7.59	10.50	54.52	193.00	11/25/2013	Settled	4.7	No	No	NA	NA	NA	12/2012	NA	NA	7
Iowa	MidAmerican Energy Co.	BRK.A	D-RPU-2013-0004	Electric	Vertically Integrated	5/17/2013	266.2	7.80	10.50	51.54	5,893.41	2/28/2014	Settled	263.6	Yes	Yes	NA	NA	NA	12/2012	NA	NA	9
Pennsylvania	Duquesne Light Co.		D-R-2013-2372129	Electric	Distribution	8/2/2013	76.3	8.36	10.50	51.94	1,543.25	4/23/2014	Settled	48.0	No	No	NA	NA	NA	04/2015	NA	NA	8
Kansas	Kansas City Power & Light	EVRG	D-14-KCPE-272-RTS	Electric	Vertically Integrated	12/9/2013	11.5	NA	10.5	NA	1,916.14	7/17/2014	Settled	11.5	No	No	NA	NA	NA	12/2011	1,916.14	Year-end	7
California	Pacific Gas and Electric Co.	PCG	AP-12-11-009 (Elec)	Electric	Vertically Integrated	11/15/2012	713.0	NA	10.5	NA	17,299.25	8/14/2014	Fully Litigated	196.0	Yes	No	NA	NA	NA	12/2014	16,822.53	Average	21
Idaho	Avista Corp.	AVA	C-AVU-E-14-05	Electric	Vertically Integrated	5/30/2014	NA	NA	10.5	NA	NA	9/18/2014	Settled	0.0	No	No	NA	NA	NA	NA	NA	NA	3
Washington	Avista Corp.	AVA	D-UE-140188	Electric	Vertically Integrated	2/4/2014	18.2	7.71	10.50	49.00	1,365.44	11/25/2014	Settled	7.0	No	No	NA	NA	NA	06/2013	NA	NA	9
Maryland	Baltimore Gas and Electric Co.	EXC	C-9355 (elec)	Electric	Distribution	7/2/2014	98.7	7.93	10.50	52.30	2,914.00	12/12/2014	Settled	22.0	No	No	NA	NA	NA	08/2014	NA	NA	5
Texas	Southwestern Public Service Co.	XEL	D-42004	Electric	Vertically Integrated	1/7/2014	76.9	8.43	10.50	53.89	1,273.28	12/18/2014	Settled	37.0	No	Yes	NA	NA	NA	06/2013	NA	NA	11
West Virginia	Monongahela Power Co.	FE	C-14-0702-E-42T	Electric	Vertically Integrated	4/30/2014	212.6	7.87	10.50	46.47	2,511.86	2/4/2015	Settled	124.3	No	No	NA	NA	NA	12/2013	NA	NA	9
South Dakota	Black Hills Power Inc.	BKH	D-EL14-026	Electric	Vertically Integrated	3/31/2014	14.6	8.48	10.50	53.32	542.70	3/2/2015	Settled	6.9	No	Yes	7.76	NA	NA	09/2013	543.93	Average	11
Pennsylvania	Metropolitan Edison Co.	FE	D-R-2014-2428745	Electric	Distribution	8/4/2014	168.3	8.05	10.50	49.96	1,413.00	4/9/2015	Settled	105.7	No	No	NA	NA	NA	04/2016	NA	NA	8
Pennsylvania	Pennsylvania Electric Co.	FE	D-R-2014-2428743	Electric	Distribution	8/4/2014	136.8	8.31	10.50	49.90	1,540.30	4/9/2015	Settled	107.8	No	No	NA	NA	NA	04/2016	NA	NA	8
Pennsylvania	Pennsylvania Power Co.	FE	D-R-2014-2428744	Electric	Distribution	8/4/2014	38.0	8.51	10.50	50.07	358.93	4/9/2015	Settled	25.5	No	No	NA	NA	NA	04/2016	NA	NA	8
Pennsylvania	West Penn Power Co.	FE	D-R-2014-2428742	Electric	Distribution	8/4/2014	114.0	8.14	10.50	50.13	1,287.29	4/9/2015	Settled	95.2	No	No	NA	NA	NA	04/2016	NA	NA	8
Oklahoma	Public Service Co. of Ok	AEP	Cs-PUD201300217	Electric	Vertically Integrated	1/17/2014	37.7	7.94	10.50	48.69	1,860.91	4/14/2015	Settled	(4.8)	No	Yes	7.63	NA	NA	07/2013	1,908.68	Year-end	15
New Mexico	Public Service Co. of NM	PNM	C-14-00332-UT	Electric	Vertically Integrated	12/11/2014	107.4	8.29	10.50	49.60	2,387.76	5/13/2015	Fully Litigated	NA	No	No	NA	NA	NA	NA	NA	NA	5
South Dakota	Northern States Power Co. - MN	XEL	D-EL14-058	Electric	Vertically Integrated	6/23/2014	24.6	7.84	10.50	53.86	433.24	6/15/2015	Settled	15.2	No	Yes	7.22	NA	NA	12/2013	412.44	Average	11
Kentucky	Kentucky Power Co.	AEP	C-2014-00396	Electric	Vertically Integrated	12/23/2014	(4.7)	7.71	10.50	45.19	1,147.48	6/22/2015	Settled	(23.0)	No	No	NA	NA	NA	09/2014	NA	NA	6
Missouri	Empire District Electric Co.	AQN	C-ER-2014-0351	Electric	Vertically Integrated	8/29/2014	24.3	7.94	10.50	51.45	1,164.92	6/24/2015	Settled	17.1	No	No	NA	NA	NA	04/2014	NA	NA	9

New Mexico	Southwestern Public Service Co	XEL	C-15-00139-UT	Electric	Vertically Integrated	6/8/2015	31.5	8.10	10.50	53.97	777.86	6/24/2015	Fully Litigated	NA	No	No	NA	NA	NA	NA	NA	NA	0
Kentucky	Kentucky Utilities Co.	PPL	C-2014-00371	Electric	Vertically Integrated	11/26/2014	153.4	7.38	10.50	53.02	3,568.97	6/30/2015	Settled	125.0	No	No	NA	NA	NA	06/2016	NA	NA	7
Kentucky	Louisville Gas & Electric Co.	PPL	C-2014-00372 (elec.)	Electric	Vertically Integrated	11/26/2014	30.3	7.36	10.50	52.75	2,146.05	6/30/2015	Settled	0.0	No	No	NA	NA	NA	06/2016	NA	NA	7
Texas	Entergy Texas Inc.	ETR	D-44704	Electric	Vertically Integrated	6/12/2015	75.9	8.36	10.50	50.08	2,004.59	7/20/2015	Fully Litigated	NA	No	No	NA	NA	NA	NA	NA	NA	1
Kansas	Westar Energy Inc.	EVRG	D-15-WSEE-115-RTS	Electric	Vertically Integrated	3/2/2015	250.9	7.99	10.50	53.12	5,062.80	9/24/2015	Settled	185.3	No	No	NA	NA	NA	09/2014	NA	NA	6
South Dakota	NorthWestern Corp.	NWE	D-EL14-106	Electric	Vertically Integrated	12/19/2014	26.5	7.76	10.50	53.61	447.40	10/29/2015	Settled	40.7	No	Yes	7.24	NA	NA	NA	NA	NA	10
California	Southern California Edison Co	EIX	A-13-11-003	Electric	Vertically Integrated	11/12/2013	(120.9)	NA	10.5	NA	18,175.82	11/5/2015	Fully Litigated	(450.4)	Yes	No	NA	NA	NA	12/2015	17,375.83	Average	24
Pennsylvania	PPL Electric Utilities Corp.	PPL	D-R-2015-2469275	Electric	Distribution	3/31/2015	167.5	8.15	10.50	51.66	3,156.00	11/19/2015	Settled	124.0	No	No	NA	NA	NA	12/2016	NA	NA	7
Virginia	Virginia Electric & Power Co.	D	C-PUE-2015-00027	Electric	Vertically Integrated	3/31/2015	0.0	NA	10.5	NA	8,921.00	11/23/2015	Fully Litigated	0.0	No	No	NA	NA	NA	12/2014	NA	NA	7
Tennessee	Kingsport Power Company	AEP	D-15-00093	Electric	Vertically Integrated	9/28/2015	12.1	6.69	10.50	42.43	71.50	12/15/2015	NA	NA	No	No	NA	NA	NA	NA	NA	NA	2
Pennsylvania	PECO Energy Co.	EXC	D-R-2015-2468981	Electric	Distribution	3/27/2015	190.1	8.19	10.50	53.36	4,103.61	12/17/2015	Settled	127.0	No	No	NA	NA	NA	12/2016	NA	NA	8
Virginia	Kentucky Utilities Co.	PPL	C-PUE-2015-00062	Electric	Vertically Integrated	6/30/2015	7.2	7.51	10.50	54.07	222.18	2/2/2016	Settled	5.5	No	No	NA	NA	NA	12/2014	NA	NA	7
Montana	MDU Resources Group Inc	MDU	D-D2015.6.51	Electric	Vertically Integrated	6/25/2015	11.8	7.59	10.50	49.52	174.96	3/25/2016	Settled	7.4	Yes	No	NA	NA	NA	12/2014	NA	NA	9
California	San Diego Gas & Electric Co.	SRE	A-14-11-003 (Elec)	Electric	Vertically Integrated	11/14/2014	91.9	NA	10.5	NA	4,606.77	6/23/2016	Settled	3.0	Yes	No	NA	NA	NA	12/2016	4,299.16	Average	19
Missouri	Empire District Electric Co.	AQN	C-ER-2016-0023	Electric	Vertically Integrated	10/16/2015	33.4	7.58	10.50	49.01	1,368.11	8/10/2016	Settled	20.4	No	No	NA	NA	NA	06/2015	NA	NA	9
New Mexico	Southwestern Public Service Co.	XEL	C-15-00296-UT	Electric	Vertically Integrated	10/16/2015	45.4	8.17	10.50	53.97	734.14	8/10/2016	Settled	23.5	No	No	NA	NA	NA	NA	NA	NA	9
Texas	El Paso Electric Co.	EE	D-44941	Electric	Vertically Integrated	8/10/2015	63.3	8.08	10.50	49.52	1,467.75	8/18/2016	Settled	40.7	No	Yes	NA	NA	NA	03/2015	NA	NA	12
Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-2016-0156 (MPS/L&P)	Electric	Vertically Integrated	2/23/2016	59.3	7.73	10.50	54.83	1,906.00	9/28/2016	Settled	3.0	No	No	NA	NA	NA	NA	NA	NA	7
Wisconsin	Northern States Power Co - Wi	XEL	D-4220-UR-122 (Elec)	Electric	Vertically Integrated	4/1/2016	28.3	NA	10.5	NA	1,188.00	10/26/2016	Fully Litigated	24.5	No	No	NA	NA	NA	12/2017	NA	NA	6
Arkansas	Entergy Arkansas Inc	ETR	D-16-036-FR	Electric	Vertically Integrated	7/22/2016	67.7	4.62	10.5	30.79	6,623.46	12/6/2016	Settled	54.4	No	No	NA	NA	NA	12/2017	NA	NA	4
Washington	Avista Corp	AVA	[illegible]	Electric	Vertically Integrated	5/19/2016	48.6	7.64	10.50	48.56	1,464.53	12/15/2016	Fully Litigated	0.0	No	No	NA	NA	NA	NA	NA	NA	10
Hawaii	Hawaiian Electric Co.	HE	D-2013-0372	Electric	Vertically Integrated	6/27/2014	0.0	8.43	10.50	56.94	1,851.91	12/23/2016	Fully Litigated	0.0	No	No	NA	NA	NA	NA	NA	NA	30
Kansas	Empire District Electric Co.	AQN	D-17-EPDE-101-RTS	Electric	Vertically Integrated	9/16/2016	6.4	7.55	10.50	49.69	81.40	1/10/2017	NA	NA	No	No	NA	NA	NA	NA	NA	NA	3
Texas	Cross Texas Transmission		D-46681	Electric	Transmission	12/6/2016	(6.5)	NA	10.5	NA	NA	1/11/2017	Settled	(6.5)	No	No	NA	NA	NA	NA	NA	NA	1
Pennsylvania	Metropolitan Edison Co.	FE	D-R-2016-2537349	Electric	Distribution	4/28/2016	140.2	8.14	10.50	51.20	1,405.89	1/19/2017	Settled	90.5	No	No	NA	NA	NA	12/2017	NA	NA	8
Pennsylvania	Pennsylvania Electric Co.	FE	D-R-2016-2537352	Electric	Distribution	4/28/2016	158.8	8.58	10.50	52.60	1,631.19	1/19/2017	Settled	94.6	No	No	NA	NA	NA	12/2017	NA	NA	8
Pennsylvania	Pennsylvania Power Co.	FE	D-R-2016-2537355	Electric	Distribution	4/28/2016	42.0	8.70	10.50	50.10	413.52	1/19/2017	Settled	27.5	No	No	NA	NA	NA	12/2017	NA	NA	8
Pennsylvania	West Penn Power Co.	FE	D-R-2016-2537359	Electric	Distribution	4/28/2016	98.2	7.90	10.50	50.30	1,364.22	1/19/2017	Settled	60.6	No	No	NA	NA	NA	12/2017	NA	NA	8
Texas	Southwestern Public Service Co.	XEL	D-45524	Electric	Vertically Integrated	2/16/2016	61.5	8.12	10.50	53.97	1,674.04	1/26/2017	Settled	35.2	No	No	NA	NA	NA	09/2015	NA	Year-end	11
Indiana	Indianapolis Power & Light Co.	AES	Ca-44693	Electric	Vertically Integrated	12/22/2016	91.7	6.81	10.50	39.55	3,041.40	2/24/2017	NA	NA	No	No	NA	NA	NA	NA	NA	NA	2
Missouri	Union Electric Co.	AEE	[illegible]	Electric	Vertically Integrated	7/1/2016	396.4	7.71	10.50	51.80	7,195.36	5/8/2017	Settled	60.5	No	No	NA	NA	NA	7/2016	NA	NA	8
New Mexico	Southwestern Public Service Co.	XEL	C-16-00269-UT	Electric	Vertically Integrated	11/1/2016	41.4	7.83	10.50	53.97	822.17	4/19/2017	Fully Litigated	0.0	No	No	NA	NA	NA	NA	NA	NA	5
California	Pacific Gas and Electric Co.	PCG	A-15-09-001 (Elec)	Electric	Vertically Integrated	9/1/2015	260.0	NA	10.5	NA	19,300.96	5/11/2017	Settled	91.0	Yes	No	NA	NA	NA	12/2017	19,159.42	Average	20
Kansas	Kansas City Power & Light	EVRG	D-17-KCPE-201-RTS	Electric	Vertically Integrated	11/9/2016	(2.8)	NA	10.5	NA	2,104.63	6/6/2017	Settled	(3.6)	No	No	NA	NA	NA	06/2014	NA	NA	6
Kansas	Westar Energy Inc.	EVRG	D-17-WSEE-147-RTS	Electric	Vertically Integrated	10/26/2016	16.4	NA	10.5	NA	NA	6/8/2017	Settled	16.4	No	No	NA	NA	NA	09/2014	NA	NA	7
Hawaii	Maui Electric Company Ltd	HE	D-2014-0318	Electric	Vertically Integrated	12/30/2014	0.0	8.28	10.50	57.43	460.07	8/4/2017	Fully Litigated	0.0	No	No	NA	NA	NA	NA	NA	NA	31
Wisconsin	Wisconsin Electric Power Co	WEC	D-5-UR-108 (WEP-Elec)	Electric	Vertically Integrated	4/4/2017	0.0	NA	10.5	NA	NA	8/10/2017	Settled	0.0	Yes	No	NA	NA	NA	12/2019	NA	NA	4
Wisconsin	Wisconsin Public Service Corp.	WEC	D-6690-UR-125 (Elec)	Electric	Vertically Integrated	4/4/2017	0.0	NA	10.5	NA	NA	8/10/2017	Settled	0.0	Yes	No	NA	NA	NA	12/2019	NA	NA	4
Texas	Oncor Electric Delivery Company	[illegible]	[illegible]	Electric	Distribution	4/29/2016	1.4	7.24	10.50	46.56	595.34	9/29/2017	Settled	(3.0)	No	Yes	NA	NA	NA	NA	NA	NA	17
Florida	Duke Energy Florida LLC	DUK	D-20170183-EI	Electric	Vertically Integrated	8/29/2017	200.0	NA	10.5	NA	NA	10/25/2017	Settled	200.0	Yes	No	NA	NA	NA	NA	NA	NA	1
Arkansas	Entergy Arkansas Inc.	ETR	D-16-036-FR (2017 Review)	Electric	Vertically Integrated	7/7/2017	126.4	4.64	10.5	31.62	7,094.57	12/13/2017	Settled	113.4	No	No	4.64	NA	31.62	12/2018	7,094.57	Average	5
Maryland	Delmarva Power & Light Co.	EXC	C-9455	Electric	Distribution	7/14/2017	19.3	7.05	10.5	50.68	740.92	2/9/2018	Settled	13.4	No	No	NA	NA	NA	09/2017	NA	NA	7
Colorado	Public Service Co. of CO	XEL	D-17AL-0649E	Electric	Vertically Integrated	10/3/2017	377.9	7.55	10.50	55.25	7,396.06	4/26/2018	Fully Litigated	NA	No	No	NA	NA	NA	NA	NA	NA	6
Virginia	Kentucky Utilities Co.	PPL	C-PUR-2017-00106	Electric	Vertically Integrated	9/29/2017	6.7	7.47	10.50	53.85	214.08	5/8/2018	Settled	1.8	No	No	NA	NA	NA	12/2016	NA	NA	7

Source: Bloomberg Professional Services

	USGG30YR Index		
Dates	PX_LAST		
3/31/2000	5.828		
6/30/2000	5.896		
9/29/2000	5.885		
12/29/2000	5.457		
3/30/2001	5.444		
6/29/2001	5.759	5.828	0.069
9/28/2001	5.421	5.896	0.475
12/31/2001	5.466	5.885	0.419
3/29/2002	5.795	5.457	-0.338
6/28/2002	5.508	5.444	-0.064
9/30/2002	4.668	5.759	1.091
12/31/2002	4.778	5.421	0.643
3/31/2003	4.815	5.466	0.651
6/30/2003	4.557	5.795	1.238
9/30/2003	4.882	5.508	0.625
12/31/2003	5.073	4.668	-0.405
3/31/2004	4.772	4.778	0.006
6/30/2004	5.288	4.815	-0.472
9/30/2004	4.892	4.557	-0.335
12/31/2004	4.826	4.882	0.056
3/31/2005	4.755	5.073	0.318
6/30/2005	4.191	4.772	0.581
9/30/2005	4.567	5.288	0.721
12/30/2005	4.535	4.892	0.357
3/31/2006	4.890	4.826	-0.064
6/30/2006	5.186	4.755	-0.431
9/29/2006	4.762	4.191	-0.571
12/29/2006	4.810	4.567	-0.243
3/30/2007	4.843	4.535	-0.308
6/29/2007	5.124	4.890	-0.234
9/28/2007	4.836	5.186	0.350
12/31/2007	4.452	4.762	0.310
3/31/2008	4.292	4.810	0.518
6/30/2008	4.524	4.843	0.319
9/30/2008	4.311	5.124	0.813
12/31/2008	2.676	4.836	2.160
3/31/2009	3.534	4.452	0.918
6/30/2009	4.329	4.292	-0.038
9/30/2009	4.050	4.524	0.474
12/31/2009	4.641	4.311	-0.330
3/31/2010	4.713	2.676	-2.037
6/30/2010	3.889	3.534	-0.355
9/30/2010	3.685	4.329	0.645
12/31/2010	4.334	4.050	-0.284
3/31/2011	4.508	4.641	0.134
6/30/2011	4.371	4.713	0.342
9/30/2011	2.913	3.889	0.975
12/30/2011	2.894	3.685	0.791
3/30/2012	3.336	4.334	0.998
6/29/2012	2.753	4.508	1.754
9/28/2012	2.823	4.371	1.548

12/31/2012	2.950	2.913	-0.036
3/29/2013	3.102	2.894	-0.208
6/28/2013	3.499	3.336	-0.164
9/30/2013	3.685	2.753	-0.931
12/31/2013	3.968	2.823	-1.145
3/31/2014	3.558	2.950	-0.608
6/30/2014	3.360	3.102	-0.258
9/30/2014	3.197	3.499	0.303
12/31/2014	2.752	3.685	0.933
3/31/2015	2.536	3.968	1.432
6/30/2015	3.124	3.558	0.435
9/30/2015	2.854	3.360	0.506
12/31/2015	3.016	3.197	0.181
3/31/2016	2.612	2.752	0.140
6/30/2016	2.285	2.536	0.251
9/30/2016	2.315	3.124	0.808
12/30/2016	3.065	2.854	-0.211
3/31/2017	3.010	3.016	0.006
6/30/2017	2.835	2.612	-0.223
9/29/2017	2.860	2.285	-0.575
12/29/2017	2.740	2.315	-0.425
3/30/2018	2.974	3.065	0.091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1.000
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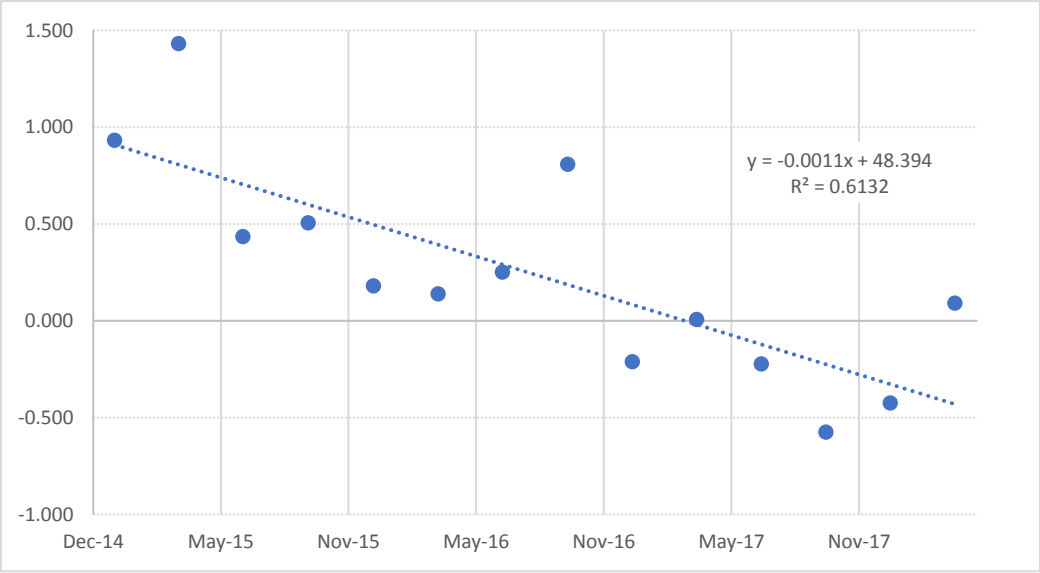
-2.500
Jan-00
Dec-01
Dec-03
Dec-05
Dec-07
Dec-09
Dec-11
Dec-13
Dec-15
Dec-17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0.500
0.000
-0.500
-1.000
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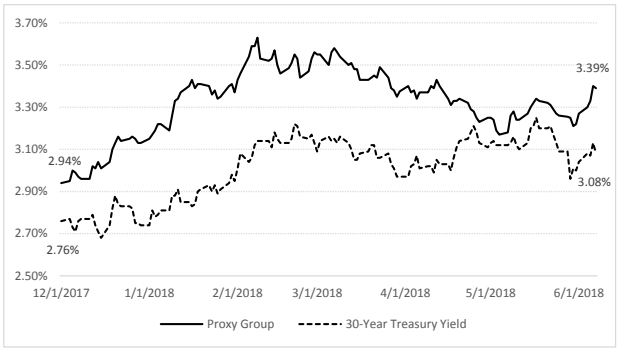
R² = 0.6132
Dec-14
May-15
Nov-15
May-16
Nov-16
May-17
Nov-17

Source: S&P Global Market Intelligence
Rate/ Yield (%) - 12/1/2017 to 6/7/2018 - Daily

	[redacted]		Proxy Group	30-Year Treasury Yield
6/7/2018	3.39	3.08	3.39%	3.08%
6/6/2018	3.40	3.13	3.40%	3.13%
6/5/2018	3.33	3.07	3.33%	3.07%
6/4/2018	3.30	3.08	3.30%	3.08%
6/1/2018	3.27	3.04	3.27%	3.04%
5/31/2018	3.22	3.00	3.22%	3.00%
5/30/2018	3.21	3.01	3.21%	3.01%
5/29/2018	3.25	2.96	3.25%	2.96%
5/28/2018	NA	3.09	3.26%	3.09%
5/25/2018	3.26	3.09	3.26%	3.09%
5/24/2018	3.27	3.13	3.27%	3.13%
5/23/2018	3.29	3.17	3.29%	3.17%
5/22/2018	3.31	3.21	3.31%	3.21%
5/21/2018	3.32	3.20	3.32%	3.20%
5/18/2018	3.33	3.20	3.33%	3.20%
5/17/2018	3.34	3.25	3.34%	3.25%
5/16/2018	3.32	3.21	3.32%	3.21%
5/15/2018	3.30	3.20	3.30%	3.20%
5/14/2018	3.27	3.13	3.27%	3.13%
5/11/2018	3.24	3.10	3.24%	3.10%
5/10/2018	3.24	3.12	3.24%	3.12%
5/9/2018	3.28	3.16	3.28%	3.16%
5/8/2018	3.26	3.13	3.26%	3.13%
5/7/2018	3.18	3.12	3.18%	3.12%
5/4/2018	3.17	3.12	3.17%	3.12%
5/3/2018	3.19	3.12	3.19%	3.12%
5/2/2018	3.24	3.14	3.24%	3.14%
5/1/2018	3.25	3.13	3.25%	3.13%
4/30/2018	3.25	3.11	3.25%	3.11%
4/27/2018	3.23	3.13	3.23%	3.13%
4/26/2018	3.25	3.18	3.25%	3.18%
4/25/2018	3.28	3.21	3.28%	3.21%
4/24/2018	3.29	3.18	3.29%	3.18%
4/23/2018	3.32	3.15	3.32%	3.15%
4/20/2018	3.34	3.14	3.34%	3.14%
4/19/2018	3.33	3.11	3.33%	3.11%
4/18/2018	3.33	3.06	3.33%	3.06%
4/17/2018	3.31	3.00	3.31%	3.00%
4/16/2018	3.34	3.03	3.34%	3.03%
4/13/2018	3.40	3.03	3.40%	3.03%
4/12/2018	3.43	3.05	3.43%	3.05%
4/11/2018	3.39	2.99	3.39%	2.99%
4/10/2018	3.40	3.02	3.40%	3.02%
4/9/2018	3.37	3.02	3.37%	3.02%
4/6/2018	3.37	3.01	3.37%	3.01%
4/5/2018	3.34	3.07	3.34%	3.07%
4/4/2018	3.38	3.03	3.38%	3.03%
4/3/2018	3.37	3.02	3.37%	3.02%
4/2/2018	3.40	2.97	3.40%	2.97%
3/30/2018	NA	2.97	3.38%	2.97%
3/29/2018	3.35	2.97	3.35%	2.97%
3/28/2018	3.38	3.01	3.38%	3.01%
3/27/2018	3.39	3.03	3.39%	3.03%
3/26/2018	3.44	3.08	3.44%	3.08%
3/23/2018	3.49	3.06	3.49%	3.06%
3/22/2018	3.44	3.06	3.44%	3.06%
3/21/2018	3.45	3.12	3.45%	3.12%
3/20/2018	3.44	3.12	3.44%	3.12%
3/19/2018	3.43	3.09	3.43%	3.09%
3/16/2018	3.43	3.08	3.43%	3.08%
3/15/2018	3.48	3.05	3.48%	3.05%
3/14/2018	3.48	3.05	3.48%	3.05%
3/13/2018	3.51	3.10	3.51%	3.10%
3/12/2018	3.50	3.13	3.50%	3.13%
3/9/2018	3.54	3.16	3.54%	3.16%
3/8/2018	3.56	3.13	3.56%	3.13%
3/7/2018	3.58	3.15	3.58%	3.15%
3/6/2018	3.56	3.14	3.56%	3.14%
3/5/2018	3.50	3.16	3.50%	3.16%
3/2/2018	3.55	3.14	3.55%	3.14%
3/1/2018	3.55	3.09	3.55%	3.09%
2/28/2018	3.56	3.13	3.56%	3.13%
2/27/2018	3.53	3.17	3.53%	3.17%
2/26/2018	3.47	3.15	3.47%	3.15%
2/23/2018	3.44	3.16	3.44%	3.16%
2/22/2018	3.53	3.21	3.53%	3.21%
2/21/2018	3.55	3.22	3.55%	3.22%
2/20/2018	3.51	3.15	3.51%	3.15%
2/19/2018	NA	3.13	3.49%	3.13%
2/16/2018	3.46	3.13	3.46%	3.13%
2/15/2018	3.50	3.15	3.50%	3.15%
2/14/2018	3.57	3.18	3.57%	3.18%
2/13/2018	3.53	3.11	3.53%	3.11%
2/12/2018	3.52	3.14	3.52%	3.14%
2/9/2018	3.53	3.14	3.53%	3.14%

0.45% 0.32%



2/8/2018	3.63	3.14	3.63%	3.14%
2/7/2018	3.59	3.12	3.59%	3.12%
2/6/2018	3.59	3.06	3.59%	3.06%
2/5/2018	3.54	3.04	3.54%	3.04%
2/2/2018	3.46	3.08	3.46%	3.08%
2/1/2018	3.43	3.01	3.43%	3.01%
1/31/2018	3.37	2.95	3.37%	2.95%
1/30/2018	3.41	2.98	3.41%	2.98%
1/29/2018	3.40	2.94	3.40%	2.94%
1/26/2018	3.35	2.91	3.35%	2.91%
1/25/2018	3.34	2.89	3.34%	2.89%
1/24/2018	3.38	2.93	3.38%	2.93%
1/23/2018	3.36	2.90	3.36%	2.90%
1/22/2018	3.40	2.93	3.40%	2.93%
1/19/2018	3.41	2.91	3.41%	2.91%
1/18/2018	3.41	2.90	3.41%	2.90%
1/17/2018	3.39	2.84	3.39%	2.84%
1/16/2018	3.43	2.83	3.43%	2.83%
1/15/2018	NA	2.85	3.40%	2.85%
1/12/2018	3.37	2.85	3.37%	2.85%
1/11/2018	3.34	2.91	3.34%	2.91%
1/10/2018	3.33	2.88	3.33%	2.88%
1/9/2018	3.26	2.88	3.26%	2.88%
1/8/2018	3.19	2.81	3.19%	2.81%
1/5/2018	3.22	2.81	3.22%	2.81%
1/4/2018	3.22	2.79	3.22%	2.79%
1/3/2018	3.19	2.78	3.19%	2.78%
1/2/2018	3.17	2.81	3.17%	2.81%
1/1/2018	NA	2.74	3.15%	2.74%
12/29/2017	3.13	2.74	3.13%	2.74%
12/28/2017	3.13	2.75	3.13%	2.75%
12/27/2017	3.15	2.75	3.15%	2.75%
12/26/2017	3.16	2.82	3.16%	2.82%
12/25/2017	NA	2.83	3.15%	2.83%
12/22/2017	3.14	2.83	3.14%	2.83%
12/21/2017	3.16	2.84	3.16%	2.84%
12/20/2017	3.13	2.88	3.13%	2.88%
12/19/2017	3.10	2.82	3.10%	2.82%
12/18/2017	3.04	2.74	3.04%	2.74%
12/15/2017	3.01	2.68	3.01%	2.68%
12/14/2017	3.04	2.71	3.04%	2.71%
12/13/2017	3.01	2.74	3.01%	2.74%
12/12/2017	3.02	2.79	3.02%	2.79%
12/11/2017	2.96	2.77	2.96%	2.77%
12/8/2017	2.96	2.77	2.96%	2.77%
12/7/2017	2.97	2.76	2.97%	2.76%
12/6/2017	2.99	2.71	2.99%	2.71%
12/5/2017	3.00	2.73	3.00%	2.73%
12/4/2017	2.95	2.77	2.95%	2.77%
12/1/2017	2.94	2.76	2.94%	2.76%

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Currency data supplied by Interactive Data Pricing and Reference Data LLC

Price/Value - 11/1/2017 to 6/7/2018 - Daily

	[redacted]		S&P 500	Proxy Group
6/7/2018	2,770.3720	90.7201	7.41%	-8.40%
6/6/2018	2,772.3458	90.3812	7.48%	-8.74%
6/5/2018	2,748.7952	92.2752	6.57%	-6.83%
6/4/2018	2,746.8711	93.1755	6.49%	-5.92%
6/1/2018	2,734.6189	93.9221	6.02%	-5.17%
5/31/2018	2,705.2748	95.4226	4.88%	-3.65%
5/30/2018	2,724.0099	95.8240	5.61%	-3.25%
5/29/2018	2,689.8572	94.5364	4.28%	-4.55%
5/25/2018	2,721.3280	94.1863	5.50%	-4.90%
5/24/2018	2,727.7632	93.8875	5.75%	-5.20%
5/23/2018	2,733.2893	93.2982	5.97%	-5.80%
5/22/2018	2,724.4440	92.4777	5.62%	-6.63%
5/21/2018	2,733.0108	92.2154	5.96%	-6.89%
5/18/2018	2,712.9747	91.9083	5.18%	-7.20%
5/17/2018	2,720.1272	91.8194	5.46%	-7.29%
5/16/2018	2,722.4623	92.4392	5.55%	-6.67%
5/15/2018	2,711.4455	92.9540	5.12%	-6.15%
5/14/2018	2,730.1325	93.8113	5.85%	-5.28%
5/11/2018	2,727.7159	94.5211	5.75%	-4.56%
5/10/2018	2,723.0689	94.5483	5.57%	-4.54%
5/9/2018	2,697.7915	93.5726	4.59%	-5.52%
5/8/2018	2,671.9183	94.1475	3.59%	-4.94%
5/7/2018	2,672.6285	96.2411	3.62%	-2.83%
5/4/2018	2,663.4203	96.6757	3.26%	-2.39%
5/3/2018	2,629.7256	96.1087	1.95%	-2.96%
5/2/2018	2,635.6685	94.5642	2.18%	-4.52%
5/1/2018	2,654.8007	94.2811	2.92%	-4.81%
4/30/2018	2,648.0494	94.4460	2.66%	-4.64%
4/27/2018	2,669.9063	94.9098	3.51%	-4.17%
4/26/2018	2,666.9428	94.3125	3.40%	-4.77%
4/25/2018	2,639.3950	93.3295	2.33%	-5.77%
4/24/2018	2,634.5565	93.2313	2.14%	-5.87%
4/23/2018	2,670.2905	92.2154	3.53%	-6.89%
4/20/2018	2,670.1418	91.6945	3.52%	-7.42%
4/19/2018	2,693.1257	92.0360	4.41%	-7.07%
4/18/2018	2,708.6390	92.0389	5.01%	-7.07%
4/17/2018	2,706.3851	92.5099	4.92%	-6.59%
4/16/2018	2,677.8396	91.6881	3.82%	-7.42%
4/13/2018	2,656.2969	90.0647	2.98%	-9.06%
4/12/2018	2,663.9948	89.3048	3.28%	-9.83%
4/11/2018	2,642.1902	90.3576	2.44%	-8.77%
4/10/2018	2,656.8680	90.2525	3.01%	-8.87%
4/9/2018	2,613.1588	90.8286	1.31%	-8.29%
4/6/2018	2,604.4694	91.0605	0.97%	-8.06%
4/5/2018	2,662.8362	91.7238	3.24%	-7.39%
4/4/2018	2,644.6880	90.7346	2.53%	-8.39%
4/3/2018	2,614.4457	90.8696	1.36%	-8.25%
4/2/2018	2,581.8816	90.1889	0.10%	-8.94%
3/29/2018	2,640.8660	91.3979	2.38%	-7.72%
3/28/2018	2,604.9975	90.7735	0.99%	-8.35%
3/27/2018	2,612.6246	90.3725	1.29%	-8.75%
3/26/2018	2,658.5542	89.1305	3.07%	-10.01%
3/23/2018	2,588.2628	87.8844	0.35%	-11.26%
3/22/2018	2,643.6922	89.1164	2.49%	-10.02%
3/21/2018	2,711.9281	88.9602	5.14%	-10.18%
3/20/2018	2,716.9422	88.9709	5.33%	-10.17%
3/19/2018	2,712.9174	89.3193	5.18%	-9.82%
3/16/2018	2,752.0118	89.4365	6.69%	-9.70%
3/15/2018	2,747.3298	88.1570	6.51%	-10.99%
3/14/2018	2,749.4823	87.9660	6.60%	-11.18%
3/13/2018	2,765.3095	87.4331	7.21%	-11.72%
3/12/2018	2,783.0193	87.5629	7.90%	-11.59%
3/9/2018	2,786.5651	86.6799	8.03%	-12.48%
3/8/2018	2,738.9694	86.1184	6.19%	-13.05%
3/7/2018	2,726.8014	85.6980	5.72%	-13.47%
3/6/2018	2,728.1220	86.1071	5.77%	-13.06%
3/5/2018	2,720.9409	87.5568	5.49%	-11.60%
3/2/2018	2,691.2528	86.2247	4.34%	-12.94%
3/1/2018	2,677.6709	86.4142	3.81%	-12.75%
2/28/2018	2,713.8305	86.2133	5.21%	-12.95%
2/27/2018	2,744.2807	86.8592	6.39%	-12.30%

2/26/2018	2,779.5960	88.4432	7.76%	-10.70%
2/23/2018	2,747.2985	89.0506	6.51%	-10.09%
2/22/2018	2,703.9613	86.7067	4.83%	-12.45%
2/21/2018	2,701.3288	86.3206	4.73%	-12.84%
2/20/2018	2,716.2555	87.2101	5.31%	-11.95%
2/16/2018	2,732.2198	88.4658	5.93%	-10.68%
2/15/2018	2,731.2041	87.6494	5.89%	-11.50%
2/14/2018	2,698.6337	85.8873	4.62%	-13.28%
2/13/2018	2,662.9429	86.8604	3.24%	-12.30%
2/12/2018	2,655.9975	86.9710	2.97%	-12.19%
2/9/2018	2,619.5456	86.5023	1.56%	-12.66%
2/8/2018	2,580.9995	84.1372	0.06%	-15.05%
2/7/2018	2,681.6601	85.1210	3.97%	-14.06%
2/6/2018	2,695.1442	85.0678	4.49%	-14.11%
2/5/2018	2,648.9391	86.3020	2.70%	-12.86%
2/2/2018	2,762.1253	88.1594	7.09%	-10.99%
2/1/2018	2,821.9759	89.1022	9.41%	-10.04%
1/31/2018	2,823.8099	90.5443	9.48%	-8.58%
1/30/2018	2,822.4339	89.6172	9.42%	-9.52%
1/29/2018	2,853.5284	89.7431	10.63%	-9.39%
1/26/2018	2,872.8678	91.0828	11.38%	-8.04%
1/25/2018	2,839.2530	91.3107	10.08%	-7.81%
1/24/2018	2,837.5440	90.2410	10.01%	-8.89%
1/23/2018	2,839.1304	90.4492	10.07%	-8.68%
1/22/2018	2,832.9741	89.4192	9.83%	-9.72%
1/19/2018	2,810.3027	89.0988	8.95%	-10.04%
1/18/2018	2,798.0303	89.1020	8.48%	-10.04%
1/17/2018	2,802.5556	89.6877	8.65%	-9.44%
1/16/2018	2,776.4200	88.7602	7.64%	-10.38%
1/12/2018	2,786.2441	88.9435	8.02%	-10.20%
1/11/2018	2,767.5581	89.6647	7.30%	-9.47%
1/10/2018	2,748.2255	90.1131	6.55%	-9.01%
1/9/2018	2,751.2852	91.9535	6.67%	-7.16%
1/8/2018	2,747.7102	93.8268	6.53%	-5.27%
1/5/2018	2,743.1478	92.9784	6.35%	-6.12%
1/4/2018	2,723.9926	93.2279	5.61%	-5.87%
1/3/2018	2,713.0610	93.8629	5.18%	-5.23%
1/2/2018	2,695.8098	94.5364	4.51%	-4.55%
12/29/2017	2,673.6105	95.7659	3.65%	-3.31%
12/28/2017	2,687.5378	95.8866	4.19%	-3.19%
12/27/2017	2,682.6199	95.1359	4.00%	-3.94%
12/26/2017	2,680.5045	94.7091	3.92%	-4.37%
12/22/2017	2,683.3373	95.4807	4.03%	-3.60%
12/21/2017	2,684.5692	94.9529	4.08%	-4.13%
12/20/2017	2,679.2481	95.7801	3.87%	-3.29%
12/19/2017	2,681.4736	96.6901	3.96%	-2.37%
12/18/2017	2,690.1583	98.4242	4.30%	-0.62%
12/15/2017	2,675.8080	99.7105	3.74%	0.68%
12/14/2017	2,652.0124	98.6298	2.82%	-0.42%
12/13/2017	2,662.8452	99.4691	3.24%	0.43%
12/12/2017	2,664.1057	99.3186	3.29%	0.28%
12/11/2017	2,659.9896	101.1524	3.13%	2.13%
12/8/2017	2,651.5010	101.1010	2.80%	2.08%
12/7/2017	2,636.9765	100.7732	2.23%	1.75%
12/6/2017	2,629.2669	100.3950	1.94%	1.37%
12/5/2017	2,629.5708	100.0620	1.95%	1.03%
12/4/2017	2,639.4370	101.5473	2.33%	2.53%
12/1/2017	2,642.2158	101.7766	2.44%	2.76%
11/30/2017	2,647.5799	102.5053	2.65%	3.50%
11/29/2017	2,626.0662	101.7349	1.81%	2.72%
11/28/2017	2,627.0440	101.5533	1.85%	2.54%
11/27/2017	2,601.4239	100.6970	0.86%	1.67%
11/24/2017	2,602.4247	100.0683	0.89%	1.04%
11/22/2017	2,597.0772	99.8950	0.69%	0.86%
11/21/2017	2,599.0292	100.3533	0.76%	1.32%
11/20/2017	2,582.1416	100.2712	0.11%	1.24%
11/17/2017	2,578.8543	100.4990	-0.02%	1.47%
11/16/2017	2,585.6432	100.9564	0.24%	1.93%
11/15/2017	2,564.6205	100.6144	-0.57%	1.59%
11/14/2017	2,578.8718	101.5092	-0.02%	2.49%
11/13/2017	2,584.8448	99.5772	0.21%	0.54%
11/10/2017	2,582.3000	98.6082	0.11%	-0.44%
11/9/2017	2,584.6213	99.3804	0.20%	0.34%
11/8/2017	2,594.3752	99.5204	0.58%	0.48%
11/7/2017	2,590.6418	99.5983	0.44%	0.56%

11/6/2017	2,591.1284	98.6456	0.46%	-0.40%
11/3/2017	2,587.8361	99.0150	0.33%	-0.03%
11/2/2017	2,579.8517	99.2431	0.02%	0.20%
11/1/2017	2,579.3558	99.0414	0.00%	0.00%

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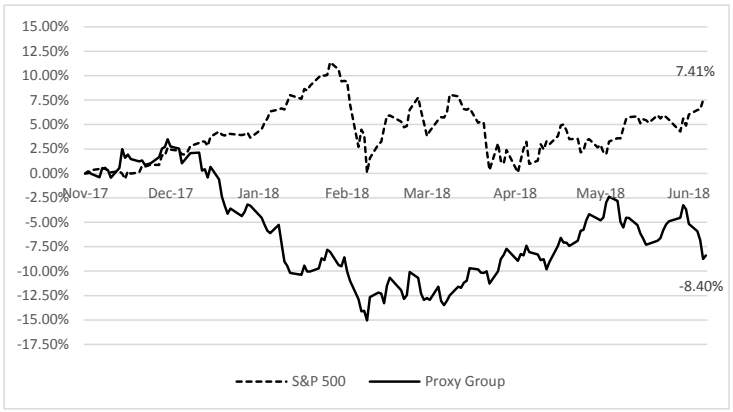
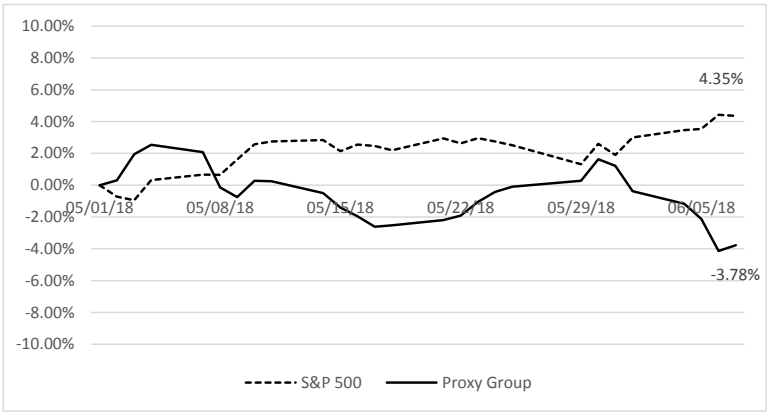
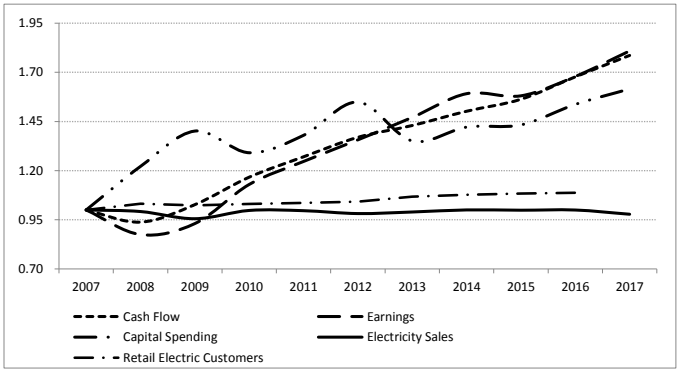
S&P 500	Proxy Group	S&P 500	Proxy Group
		4.35%	-3.78%
		4.43%	-4.14%
		3.54%	-2.13%
		3.47%	-1.17%
		3.01%	-0.38%
		1.90%	1.21%
		2.61%	1.64%
		1.32%	0.27%
		2.51%	-0.10%
		2.75%	-0.42%
		2.96%	-1.04%
		2.62%	-1.91%
		2.95%	-2.19%
		2.19%	-2.52%
		2.46%	-2.61%
		2.55%	-1.95%
		2.13%	-1.41%
		2.84%	-0.50%
		2.75%	0.25%
		2.57%	0.28%
		1.62%	-0.75%
		0.64%	-0.14%
		0.67%	2.08%
		0.32%	2.54%
		-0.94%	1.94%
		-0.72%	0.30%
		0.00%	0.00%
-1.11%	9.29%		
-0.29%	9.83%		
-0.40%	9.14%		
-1.43%	8.00%		
-1.61%	7.89%		
-0.28%	6.71%		
-0.28%	6.11%		
0.58%	6.51%		
1.16%	6.51%		
1.07%	7.05%		
0.01%	6.10%		
-0.80%	4.22%		
-0.51%	3.35%		
-1.33%	4.56%		
-0.78%	4.44%		
-2.41%	5.11%		
-2.73%	5.38%		
-0.55%	6.14%		
-1.23%	5.00%		
-2.36%	5.16%		
-3.58%	4.37%		
-1.37%	5.77%		
-2.71%	5.04%		
-2.43%	4.58%		
-0.71%	3.14%		
-3.34%	1.70%		
-1.27%	3.13%		
1.28%	2.95%		
1.47%	2.96%		
1.32%	3.36%		
2.78%	3.50%		
2.60%	2.02%		
2.68%	1.80%		
3.27%	1.18%		
3.93%	1.33%		
4.07%	0.31%		
2.29%	-0.34%		
1.83%	-0.83%		
1.88%	-0.36%		
1.62%	1.32%		
0.51%	-0.22%		
0.00%	0.00%		





	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Revenue	1.00	1.11	0.95	1.03	1.10	1.03	1.01	1.01	0.97	0.97	1.01
Cash Flow	1.00	0.94	1.03	1.17	1.27	1.37	1.43	1.50	1.56	1.68	1.79
Earnings	1.00	0.87	0.93	1.13	1.25	1.36	1.47	1.59	1.58	1.68	1.81
Capital Spending	1.00	1.22	1.40	1.29	1.38	1.55	1.35	1.42	1.43	1.54	1.62
Electricity Sales	1.00	0.99	0.96	1.00	1.00	0.98	0.99	1.00	1.00	1.00	0.98
Retail Electric Customers	1.00	1.03	1.02	1.03	1.04	1.04	1.07	1.08	1.08	1.09	-



Source: Value Line

		SHARES OUTSTANDING										
		2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
ALLETE, Inc.	ALE	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	49.10	49.60	51.10
Alliant Energy Corporation	LNT	220.72	220.90	221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	231.35
Black Hills Corporation	BKH	37.80	38.64	38.97	39.27	43.92	44.21	44.50	44.67	51.19	53.38	53.54
El Paso Electric Company	EE	45.15	44.88	43.92	42.57	39.96	40.11	40.27	40.36	40.44	40.52	40.58
Hawaiian Electric Industries, Inc.	HE	83.43	90.52	92.52	94.69	96.04	97.93	101.26	102.57	107.46	108.58	108.79
IDACORP, Inc.	IDA	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.34	50.40	50.42
Northwestern Corporation	NWE	38.97	35.93	36.00	36.23	36.28	37.22	38.75	46.91	48.17	48.33	49.37
OGE Energy Corp.	OGE	183.60	187.00	194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	199.70
PNM Resources, Inc.	PNM	76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	79.65	79.65	79.65

ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Black Hills Corporation	BKH
El Paso Electric Company	EE
Hawaiian Electric Industries, Inc.	HE
IDACORP, Inc.	IDA
Northwestern Corporation	NWE
OGE Energy Corp.	OGE
PNM Resources, Inc.	PNM

Notes
Source: Value Line Reports as of 5/31/2018

REVENUE PER SHARE

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	30.27	27.01	27.78
15.57	16.67	15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	14.62
18.41	26.03	32.58	33.29	28.96	26.55	28.67	31.20	25.48	29.47	31.38
19.43	23.15	18.85	20.61	22.97	21.26	22.11	22.74	21.01	21.89	22.59
30.40	35.56	24.96	28.14	33.76	34.46	31.98	31.59	24.22	21.92	23.49
19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.23	25.04	26.76
30.79	35.09	31.72	30.66	30.80	28.76	29.80	25.68	25.21	26.01	26.45
20.68	21.77	14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	11.32
24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	18.07	17.11	18.14

TOTAL REVENUE

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
841.76	800.98	759.26	907.17	928.13	961.36	1018.44	1136.94	1486.26	1339.70	1419.56
3436.61	3682.40	3432.52	3415.57	3665.88	3094.26	3277.32	3350.24	3254.03	3319.43	3382.34
695.90	1005.80	1269.64	1307.30	1271.92	1173.78	1275.82	1393.70	1304.32	1573.11	1680.09
877.26	1038.97	827.89	877.37	917.88	852.74	890.37	917.79	849.64	886.98	916.70
2536.27	3218.89	2309.30	2664.58	3242.31	3374.67	3238.29	3240.19	2602.68	2380.07	2555.48
879.12	960.45	1049.97	1036.13	1026.47	1080.95	1246.21	1282.39	1270.08	1262.02	1349.24
1199.89	1260.78	1141.92	1110.81	1117.42	1070.45	1154.75	1204.65	1214.37	1257.06	1305.84
3796.85	4070.99	2869.26	3716.61	3916.15	3671.41	2868.33	2452.62	2196.70	2258.61	2260.60
1914.11	1959.90	1647.60	1673.60	1700.53	1342.10	1387.50	1436.09	1439.28	1362.81	1444.85
16177.77	17999.18	15307.36	16709.13	17786.70	16621.71	16357.02	16414.60	15617.36	15639.79	16314.69
1.00	1.11	0.95	1.03	1.10	1.03	1.01	1.01	0.97	0.97	1.01

EARNINGS PER SHARE

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	3.38	3.14	3.13
1.35	1.27	0.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	1.99
2.68	0.18	2.32	1.66	1.01	1.97	2.61	2.89	2.83	2.63	3.38
1.63	1.73	1.50	2.07	2.48	2.26	2.20	2.27	2.03	2.39	2.42
1.11	1.07	0.91	1.21	1.44	1.67	1.62	1.64	1.50	2.29	1.64
1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.87	3.94	4.21
1.44	1.77	2.02	2.14	2.53	2.26	2.46	2.99	2.90	3.39	3.34
1.32	1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	1.92
0.76	0.11	0.58	0.87	1.08	1.31	1.41	1.45	1.64	1.65	1.92

TOTAL EARNINGS

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
94.86	91.93	66.53	78.40	99.38	101.65	108.88	133.11	165.96	155.74	159.94
297.97	280.54	210.24	306.07	306.42	339.61	366.12	386.05	383.49	375.66	460.39
101.30	6.96	90.41	65.19	44.36	87.09	116.15	129.10	144.87	140.39	180.97
73.59	77.64	65.88	88.12	99.10	90.65	88.59	91.62	82.09	96.84	98.20
92.61	96.86	84.19	114.57	138.30	163.54	164.04	168.21	161.19	248.65	178.42
83.81	102.29	126.46	145.76	167.83	169.04	182.84	193.54	194.82	198.58	212.27
56.12	63.60	72.72	77.53	91.79	84.12	95.33	140.26	139.69	163.84	164.90
242.35	233.75	258.02	292.80	339.43	353.70	385.09	394.81	337.49	337.49	383.42
58.38	9.52	50.27	75.40	86.02	104.34	112.31	115.49	130.63	131.42	152.93
1101.00	963.08	1024.72	1243.85	1372.62	1493.75	1619.34	1752.20	1740.23	1848.61	1991.43
1.00	0.87	0.93	1.13	1.25	1.36	1.47	1.59	1.58	1.68	1.81

CASH FLOW PER SHARE

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	6.79	7.08	6.59
2.56	2.28	2.10	2.60	2.75	2.95	3.34	3.44	3.45	3.45	3.97
5.29	2.95	5.41	4.88	4.01	5.59	5.93	6.25	5.67	6.28	7.15
3.86	4.16	4.07	5.15	6.05	5.66	5.65	5.87	5.75	5.98	6.17
3.01	2.72	2.59	2.88	3.18	3.28	3.22	3.41	3.31	4.17	3.68
4.11	4.27	5.07	5.35	5.84	5.93	6.29	6.58	6.70	6.86	7.50
3.7	4.40	4.62	4.76	5.42	5.18	5.45	5.39	5.92	6.74	6.76
2.39	2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	3.34
2.54	1.76	2.32	2.67	3.18	3.38	3.51	3.62	3.98	4.28	5.30

TOTAL CASH FLOW

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
136.14	137.90	125.66	155.73	184.13	197.39	221.49	260.71	333.39	351.17	336.75
565.04	503.65	464.75	576.65	610.61	654.81	741.11	763.23	782.87	785.46	918.46
199.96	113.99	210.83	191.64	176.12	247.13	263.89	279.19	290.25	335.23	382.81
174.28	186.70	178.75	219.24	241.76	227.02	227.53	236.91	232.53	242.31	250.38
251.12	246.21	239.63	272.71	305.41	321.21	326.06	349.76	355.69	452.78	400.35
185.20	200.35	242.85	264.34	291.71	297.45	315.95	330.78	337.28	345.74	378.15
144.19	158.09	166.32	172.45	196.64	192.80	211.19	252.84	285.17	325.74	333.74
438.80	448.80	521.86	587.55	649.42	729.14	686.81	677.96	645.03	661.01	667.00
195.10	152.29	201.07	231.41	253.29	269.22	279.57	288.33	317.01	340.90	422.15
2289.83	2147.99	2351.73	2671.72	2909.07	3136.18	3273.59	3439.72	3579.22	3840.34	4089.78
1.00	0.94	1.03	1.17	1.27	1.37	1.43	1.50	1.56	1.68	1.79

CAPITAL SPENDING PER SHARE

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	5.84	5.35	4.08
2.46	3.98	5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	6.34
6.92	8.51	8.90	12.04	10.03	7.90	7.97	8.92	8.90	8.89	6.09
4.63	5.36	5.95	5.27	5.90	6.70	7.18	8.50	8.55	7.03	5.91
2.62	3.12	3.29	1.92	2.45	3.32	3.49	3.31	3.39	3.04	4.55
6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	5.84	5.89	5.66
3.00	3.47	5.26	6.30	5.20	5.89	5.95	5.76	5.89	5.96	5.60
3.04	4.01	4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	4.13
5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	7.01	7.53	6.28

TOTAL CAPITAL SPENDING

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
210.06	301.22	318.56	248.81	239.25	405.82	328.30	572.83	286.74	265.36	208.49
542.97	879.18	1201.71	867.20	672.78	1158.68	736.67	838.67	964.41	1197.54	1466.76
261.58	328.83	346.83	472.81	440.52	349.26	354.67	398.46	455.59	474.55	326.06
209.04	240.56	261.32	224.34	235.76	268.74	289.14	343.06	345.76	284.86	239.83
218.59	282.42	304.39	181.80	235.30	325.13	353.40	339.51	364.29	330.08	494.99
287.93	243.51	251.95	338.46	337.66	239.76	235.08	273.97	293.99	296.86	285.38
116.91	124.68	189.36	228.25	188.66	219.23	230.56	270.20	283.72	288.05	276.47
558.14	749.87	847.78	851.07	1271.38	1155.96	990.52	570.28	547.18	661.01	824.76
456.25	345.25	287.74	281.68	326.57	309.04	348.07	460.38	558.35	599.76	500.20
2861.47	3495.53	4009.66	3694.43	3947.87	4431.62	3866.40	4067.36	4100.03	4398.07	4622.94
1.00	1.22	1.40	1.29	1.38	1.55	1.35	1.42	1.43	1.54	1.62

RETAIL ELECTRIC CUSTOMERS

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
155304	156131	158479	160294	158336	157776	159237	159704	159737	160335	161135
978486	980480	981817	982835	984773	986962	990683	993465	978973	954311	959236
104504	199180	200107	201977	201934	202520	203540	205172	206547	208193	210108
354203	361034	367031	373155	378547	383588	391774	397014	402518	408504	415602
437490	440507	374431	375846	377441	379097	450475	453630	456642	459065	NA
477094	484535	488175	490705	493532	498282	504653	511957	520546	529901	539590
385724	391049	394869	397760	400281	403193	406533	415232	420572	425741	431099
759575	766886	773897	780181	786522	794320	802834	811190	820059	830057	838252
706684	716504	723637	731211	735348	738635	743332	749393	756545	763930	NA
4359064	4496306	4462443	4493964	4516714	4544373	4653061	4696757	4722139	4740037	3555022
1.00	1.03	1.02	1.03	1.04	1.04	1.07	1.08	1.08	1.09	0.82

Table 7.6 Electricity End Use

Period	Residential	Commercial	Industrial	All Sectors
2007	1,392,241	1,336,315	####	3,756,388
2008	1,380,662	1,336,133	####	3,726,311
2009	1,364,758	1,306,853	917,416	3,589,027
2010	1,445,708	1,330,199	971,221	3,747,129
2011	1,422,801	1,328,057	991,316	3,742,174
2012	1,374,515	1,327,101	985,714	3,687,330
2013	1,394,812	1,337,079	985,352	3,717,243
2014	1,407,208	1,352,158	997,576	3,756,943
2015	1,404,096	1,360,752	986,508	3,751,356
2016	1,411,058	1,367,191	976,715	3,754,965
2017	1,378,819	1,349,208	946,443	3,674,470

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
US Sales (MWh):	3,756,388	3,726,311	3,589,027	3,747,129	3,742,174	3,687,330	3,717,243	3,756,943	3,751,356	3,754,965	3,674,470
INDEX	1.00	0.99	0.96	1.00	1.00	0.98	0.99	1.00	1.00	1.00	0.98

(Million Kilowatthours)
https://www.eia.gov/totalenergy/data/browser/?tbl=T07.06#/?f=A&start=2007&end=2017&charted=5-6-7

S&P Capital IQ

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ALLETE, Inc. NYSE:ALE

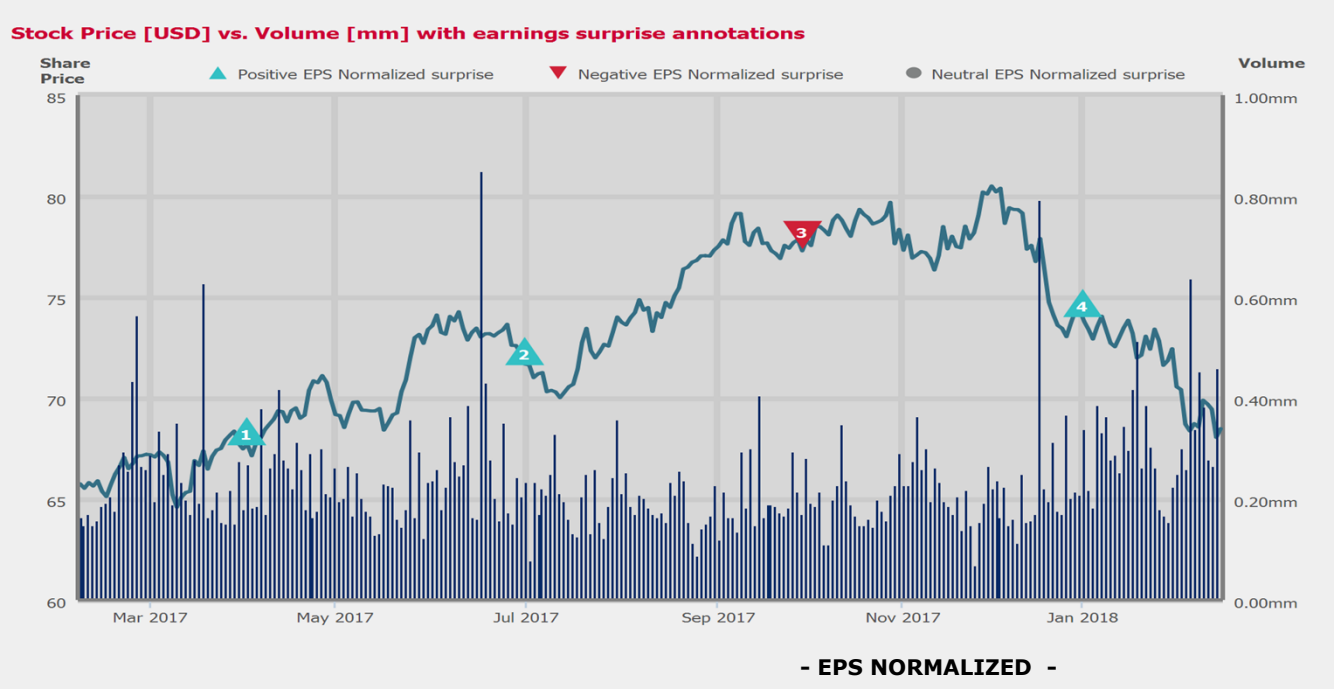
FQ1 2018 Earnings Call Transcripts

Wednesday, May 02, 2018 2:00 PM GMT

S&P Capital IQ Estimates

	-FQ1 2018-			-FQ2 2018-	-FY 2018-	-FY 2019-
	CONSENSUS	ACTUAL	SURPRISE	CONSENSUS	CONSENSUS	CONSENSUS
EPS Normalized	0.98	0.99	1.02	0.72	3.41	3.66
Revenue	-	-	0.90	-	-	-
Revenue (mm)	355.00	358.20	-	342.00	1448.65	1481.26

Currency: USD
Consensus as of Apr-30-2018 11:55 AM GMT



- EPS NORMALIZED -

	CONSENSUS	ACTUAL	SURPRISE
FQ1 2017	0.94	0.97	1 3.19 %
FQ2 2017	0.55	0.72	2 30.91 %
FQ3 2017	0.94	0.88	3 (6.38 %)
FQ4 2017	0.73	0.78	4 6.85 %

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Call Participants

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Chairman, President & CEO

Robert J. Adams
Senior VP & CFO

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Presentation

Operator

Good day, and welcome to the ALLETE First Quarter 2018 Financial Results Call. Today's call is being recorded. Certain statements contained in this conference call are not descriptions of historical facts are forward-looking statements, such as terms defined in the Private Securities Litigation Reform Act of 1995, because such statements can include risks and uncertainties, actual results may differ materially from those expressed or implied by such forward-looking statements.

Factors that could cause results to differ materially from those expressed or implied by such forward-looking statements include, but are not limited to those discussed in filings made by the company with the Securities and Exchange Commission. Many of the factors that will determine the company's future results are beyond the ability of management to control or predict. Listeners should not place undue reliance on forward-looking statements, which reflect management views only as of the date hereof. The company undertakes no obligation to revise or update any forward-looking statements or to make any other forward-looking statements, whether as a result of new information, future events or otherwise.

For opening remarks and introductions, I'd now like to turn the conference over to ALLETE President and Chief Executive Officer, Alan Hodnik. Please go ahead.

Alan R. Hodnik
Chairman, President & CEO

Good morning, everyone, and thanks for joining us today. With me are ALLETE's Senior Vice President and Chief Financial Officer, Bob Adams; and ALLETE's Vice President, Controller and Chief Accounting Officer, Steve Morris.

Today we reported first quarter 2018 financial results of $0.99 per share, a net income of $51 million. The results for the quarter were consistent with our expectations, and demonstrate the benefit of our differentiated growth strategy.

Before Steve and Bob go through the details from the quarter, I would like to highlight several areas of interest. We take great pride in delivering value to our shareholders with ALLETE's differentiated strategy. A balanced strategy built upon a foundation of long-standing commitment to environmental, social and strong governance values. We strongly believe in the importance of how we deliver value to our shareholders with annual earnings growth and dividends underpinned by our culture that incorporates a longer view and sustainability in all of our strategies. Building upon our strategic positioning, we expect to see the benefits of our differentiated strategy throughout the remainder of this year and into the foreseeable future.

Minnesota Power's Energy Forward strategy includes plans for generation sourced from the Nemadji Trail Energy Center or NTEC. A new natural gas facility that supports additional renewable generation and grid stability as well as the Great Northern Transmission Line to be completed in 2020, which will move carbon-free hydro energy from Canada. Both of these initiatives provide new opportunities for sustainable investments that further add to our history of environmental stewardship. Regarding the Minnesota Power rate review status, Minnesota Power filed for a reconsideration in early April, and Steve will provide you more details in a moment.

Minnesota Power fully intends to earn its allowed ROE and has already made some difficult decisions, which include workforce reductions and other expense management efforts, while still meeting its obligations to provide safe and reliable services to its customers. The combination of an allowed ROE that is lower than industry average and disallowance of certain expenses, transmission revenue and the inequitable treatment of prepaid pension as part of the commission's order are somewhat challenging, but Minnesota Power is working diligently to earn its allowed ROE, while balancing various stakeholder interests.

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We are pleased that Minnesota Power's taconite customers are operating at near full production. We anticipate continued strength supported by an improving economy, and actions by the Trump administration to reduce excessive imports that damage our country's steel industry. As mentioned last quarter, we are excited to see taconite customers making new long-term investments in their mining operations. There has also been constructive progress in the permitting process for Minnesota Power's new potential non-service mining customer. These industries are important to our region and to Minnesota Power, and we believe they are well-positioned to benefit along with other stakeholders as our country pursues infrastructure upgrades along with a clean energy economy. ALLETE Clean Energy is making significant progress with its already announced initiatives to refurbish 385 turbines at several of its wind energy facilities, as well as construction startup on several renewable projects for others. In addition, ALLETE Clean Energy continues to evaluate a robust pipeline of potential projects with its strategic investment in wind turbines, already qualified for federal production tax credit safe harbor provisions. 2018 is a foundational year for ALLETE, as we expect improved positioning and growing returns from our business segments.

I will provide additional comments in my closing remarks, but first I will ask Steve and Bob to go through the first quarter financial details. Steve?

Steven Wayne Morris
VP, Controller & Chief Accounting Officer

Thanks, Al, and good morning, everyone. I would like to remind you that we filed our 10-Q this morning, and encourage you to refer to it for more details on the first quarter results. For the first quarter of 2018, ALLETE reported net income of $51 million or $0.99 per share compared to $49 million or $0.97 per share for the same period in 2017.

Our 2018 results reflect approximately $600,000 after tax of severance-related expenses. Earnings were diluted by $0.02 due to additional shares of common stock outstanding as of March 31, 2018. ALLETE's Regulated Operations segment, which includes Minnesota Power, Superior Water, Light and Power and the company's investment in the American Transmission Company, recorded net income of $43.9 million, an increase of $400,000 compared to the same quarter last year. Net income at Minnesota Power was slightly lower than 2017 results, primarily due to the timing of reserves recorded for an interim rate refund, discounts provided to EITE customers, a lower transmission revenue and higher property tax expense. These decreases were mostly offset by lower depreciation expense due to the timing of the Minnesota Public Utilities Commission's decision to modify the depreciable lives at the Boswell Energy Center, as well as lower operating and maintenance expense, higher sales to industrial customers due to the start-up of United States Steel Keewatin Taconite plants in March 2017, and higher sales to residential customers due to favorable weather conditions.

If you recall, we recorded the full year impact in the fourth quarter of 2017 of interim rate refund reserves and lower depreciation expense as a result of the January 18, 2018, commission's decision in our 2016 rate review. We will continue to see these timing impacts throughout the remaining quarters of 2018. Net income at Superior Water, Light and Power was higher due to a full quarter of new rates this year, which were implemented in August 2017 and colder weather in the first quarter of 2018 compared to last year.

A few additional comments on Minnesota Power's rate review status. On April 2, 2018, Minnesota Power filed a petition for reconsideration at the Minnesota Public Utilities Commission requesting reconsideration of certain decisions in the commission's order dated March 12, 2018, representing approximately $20 million to $25 million in additional annual revenue. Minnesota Power requested reconsideration for certain items, which included the allowed return on common equity, recovery of the prepaid pension asset and rate base, certain disallowed expenses, and certain transmission revenue adjustments. The Minnesota Department of Commerce filed a separate request for reconsideration, proposing to reduce the depreciable lives of Boswell Unit 3, Unit 4 and common facilities to 2035, and use the benefits of tax reform to offset the resulting increase in customer rates.

On April 12, 2018, Minnesota Power responded to the Department of Commerce request for reconsideration, and stated that with modification in conditions, the commission should generally accept the Department of Commerce proposal. We expect a decision on reconsideration by mid-2018.

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A couple of updates on the open dockets related to tax reform for our Regulated Operations. In December of 2017, the Minnesota Public Utilities Commission opened a docket to review the effects of tax reform in Minnesota. Minnesota Power submitted an initial filing to the commission, in which it proposed to use the net tax benefits to offset other regulated costs to the extent the company is able to earn its allowed return on equity, and for the remainder of the benefits to customers through a new tax cost recovery rider. And as I noted, Minnesota Power responded to the Department of Commerce proposal that the commission generally accept with modifications and conditions the Department of Commerce proposal to shorten the lives of our Boswell Unit 3, Unit 4 and common facilities to 2035, while utilizing the benefits of tax reform. We anticipate a commission hearing and decision on this proposal in the second half of this year.

In February of 2018, Superior Water, Light and Power filed comments with the Public Service Commission of Wisconsin and proposed deferring the benefits of tax reforms and incorporating any impacts into its next general rate review. Superior Water, Light and Power expects to file a rate review later this year.

Next, a few details from our other business segments. Net income at ALLETE Clean Energy increased $1.4 million or 21% from 2017. Net income in 2018 was higher by $1.2 million, due to a lower federal income tax rate as a result of tax reform, and $600,000 after tax due to additional production tax credits as ALLETE Clean Energy continues to execute on its refurbishment strategy. These increases were partially offset by higher operating and maintenance expenses. U.S. Water Services net loss increased $1.1 million from 2017. The net loss in 2018 includes higher operating expense, partially offset by increased revenue, primarily resulting from the September 2017 acquisition of Tonka Water.

And the first quarter of 2018 was also impacted -- negatively impacted by the timing of equipment sales and colder weather conditions, which reduced chemical sales. The net loss in 2018 included $300,000 of after-tax expense related to purchase accounting impacts. ALLETE's effective tax rate for the first quarter was a 7.8% benefit compared to 21.1% expense in 2017. The decrease from 2017 was primarily due to the reduction of the federal income tax rate from 35% to 21% and lower pretax income. ALLETE's financial position is supported by increased cash flow and a strong balance sheet. Cash from operating activities was $121.3 million year-to-date and our debt to capital ratio was 42% as of March 31, 2018.

I'll now hand it off to Bob to review our earnings guidance and positioning for 2018. Bob?

Robert J. Adams
Senior VP & CFO

Thanks, Steve, and good morning, everyone. Today we reaffirmed our 2018 earnings guidance at a range of $3.20 to $3.50 per share, on net income of $165 million to $185 million. This guidance range is comprised of Regulated Operations segment, earnings within a range of $2.45 to $2.65 per share and energy infrastructure and related services businesses, which includes ALLETE Clean Energy and U.S. Water Services and corporate and other earnings within a range of $0.75 to $0.85 per share. Our differentiated growth outlook anticipates average annual long-term earnings growth of 5% to 7%. This includes growth from the Regulated Operations segment of approximately 3% to 4%, and approximately 15% average annual growth from our energy infrastructure and related services businesses over the long term.

We expect improving financial performance over time for Minnesota Power as it continues on its path to earn its authorized ROE in 2019, through a combination of expense management, small coal plant closures, potential rate review reconsideration, and legislative and other regulatory outcomes. Our rating agencies are closely monitoring the status of Minnesota Powers reconsideration filing and the outcome as an indication of the regulatory environment and the company's ability to earn its allowed return on equity. Consistent with all of the ALLETE businesses, earning our cost of capital is a priority for the long-term sustainability of our company.

As you know, ALLETE Clean Energy focuses on developing, acquiring and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates approximately 535 megawatts of wind energy generation that is contracted under power sales agreements of various durations. In mid-March, we were pleased to announce ALLETE Clean Energy's newest project to build, own and operate an 80 megawatt wind energy facility pursuant to a 15-year power sales agreement with NorthWestern Corporation. Construction is expected to be completed in 2019. Upon completion of this project along with

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the previously announced project to build, own and operate a wind energy facility for Northern States Power, ALLETE Clean Energy will have over 700 megawatts of carbon-free, renewable wind generation in its portfolio.

For this robust project development backlog of approximately 465 megawatts, which includes the Clean Energy 1 project, the South Peak project, and the refurbishment projects yet to complete, ALLETE Clean Energy has proposed and bid approximately 900 megawatts of additional PTC projects and is evaluating more than a dozen potential existing renewable facility acquisitions.

U.S. Water Services quarterly financial results reflect selling certain products that are seasonal in nature with higher demand typically realized in warmer months. So it is not unusual to experience weaker financial results in the first quarter. I remain excited about the prospects for all of our businesses at ALLETE and look forward to updating you throughout the year with our differentiated multifaceted growth platform.

We are well on our way with a new and exciting chapter at ALLETE. Al?

Alan R. Hodnik
Chairman, President & CEO

Well, thank you for the financial update, Steve and Bob. ALLETE is an energy company with a differentiated strategy. We recognize that the impacts from human activity including climate change are real, complex and interrelated. And we have thoughtfully positioned the company to do more than just operate, but to be a recognized leader to address these issues through our family of businesses. Our strategy is intentionally designed to provide cleaner energy solutions through initiatives at our regulated utility businesses, and also at our complementary and growing Energy Infrastructure and Related Services businesses. As we have shared previously, Minnesota Power's Energy Forward Strategy includes a proposal to further balance and diversify its energy sources with the Nemadji Trail Energy Center natural gas facility. In 2017, the Minnesota Public Utilities Commission directed that the related natural gas energy power purchase agreement be decided through an administrative law judge process. Recently the Minnesota Department of Commerce weighted favorably relative to the role of and the need for the NTEC initiative. The administrative law judge is expected to provide a recommendation by July of 2018, and the company anticipates a commission decision in the second half of 2018. The Minnesota Public Utilities Commission did not take any action regarding the tandem or complementary wind and solar energy power purchase agreements, which will be refiled separately, but still parallel to the natural gas initiative. Minnesota Power believes the optimal generation mix that best balances the sustainability, reliability and affordability interest of our nation and Minnesota Power's customers is a combination of 2/3 renewable and renewable enabling natural gas, and 1/3 environmentally compliant coal generation. Also in progress as part of our energy forward initiative is the ongoing construction of the Great Northern Transmission Line. The GNTL is designed to deliver carbon-free hydroelectric power from Northern Manitoba by 2020. Minnesota experienced a more traditional winter, which supported more efficient construction activity on the frozen swamps and bogs of Northern Minnesota. Minnesota Power expects to spend approximately $100 million on construction this year, with an estimated total investment of $330 million upon completion of the transmission line.

Superior Water, Light and Power continues to invest in growth initiatives to enhance the quality and reliability of electric, gas and water services provided to its customers. In support of these initiatives, the company anticipates capital investment of approximately $20 million in 2018, and anticipates filing for a rate review later this year. On the new customer front, PolyMet's proposed copper, nickel and precious metal mining operation in Northeastern Minnesota, continues to make progress on major permitting milestones.

In January of this year, the Minnesota Department of Natural Resources and the Minnesota Pollution Control Agency released PolyMet's draft permit to mines and also its air and water discharge permits. The last required public hearings for these permits were held in the first quarter of this year. The U.S. Forest Service has previously authorized a land exchange with PolyMet and continues to work with the company on the final title transfer. Upon completion, this will result in PolyMet obtaining surface rights to land needed to develop its mining operation. The final environmental impact statement also requires records

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of decision by federal agencies, which are expected in 2018. Minnesota Power could supply between 45 to 50 megawatts of new load under a 10-year power supply contract that would begin upon start-up of the mining operations.

And now a few comments on ALLETE's Energy Infrastructure and Related Services businesses. ALLETE Clean Energy is making significant progress with its construction activities to refurbish wind turbines located at 3 wind farms in Minnesota and Iowa. ACE and its project teams are on schedule to complete these refurbishment initiatives in the planned 2020 time frame. These initiatives will improve performance and availability of these facilities, while generating federal production tax credits, as they resume generating carbon free energy for their customers.

We believe the long-term operational benefits and resulting economics from these refurbished facilities will benefit the renewal of power sales agreements, further contributing to ALLETE Clean Energy's long-term financial performance. ALLETE Clean Energy is about to ramp up construction activity on an energy facility, it will sell to Montana-Dakota Utilities upon completion. Construction is on schedule and the project is expected to be completed in the second half of 2018. With its strategic investment in production tax credit -- tax qualified Safe Harbor turbines, ALLETE Clean Energy is an attractive partner as it evaluates additional renewable projects and formally bids into a nationwide pipeline of renewable RFPs. The next several years will be transforming to earnings growth, to larger scale, and to project construction activity for ALLETE Clean Energy, as it moves forward with its multifaceted growth strategy.
Lastly, we believe U.S. Water Services is well-positioned for growth, as it captures revenue streams in the emerging integrated water management industry. With our first quarter financial results behind us, we are confident that our differentiated strategy is positioned to provide growth and earnings as well as dividends. We believe ALLETE's family of businesses will continue to benefit from investment growth opportunities, primarily driven by demands for cleaner energy and water conservation, along with our nation's renewed focus on infrastructure upgrades and expansion. Thank you for your time and for your investment in ALLETE. And at this time, I will ask the operator to open up the line for your questions.

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Question and Answer

Operator

[Operator Instructions] And our first question comes from Paul Ridzon from KeyBanc.

Paul Thomas Ridzon
KeyBanc Capital Markets Inc., Research Division

This request for reconsideration, you said $20 million to $25 million, that could really move the needle? Could that by any chance be retroactive depending on what comes out of it?

Steven Wayne Morris
VP, Controller & Chief Accounting Officer

Yes, hi Paul, Steve Morris. It would be as of most likely January 1, 2017 that's when we started to implement our interim rate refund reserve, or that's what the effective date would be. So we would go back and adjust that through that period of time up through today.

Paul Thomas Ridzon
KeyBanc Capital Markets Inc., Research Division

Thank you, and when do you expect that to be decided?

Steven Wayne Morris
VP, Controller & Chief Accounting Officer

Well, tentatively there's a hearing this month, so we would, and that could get changed, but we would expect that to be heard and decided in the second quarter, so by the time we have our second quarter results.

Paul Thomas Ridzon
KeyBanc Capital Markets Inc., Research Division

And then just some clarification. The department made their proposal regarding Boswell and tax reform, is that going to be consolidated with your proposal to hit your ROE and then start getting back? Or -- what's the procedural schedule on those?

Steven Wayne Morris
VP, Controller & Chief Accounting Officer

Yes, I think they are 2 separate things. So one of our proposals was in response to the Department of Commerce proposal to go back now and shorten the lives to 2035 for Boswell was that would be heard in conjunction with our tax filing and not part of a rate case. And so that's really a cash issue, it's not an ROE issue.

Paul Thomas Ridzon
KeyBanc Capital Markets Inc., Research Division

The department's proposal, and your proposal to hit your authorized return before you give back would be the same proceeding?

Steven Wayne Morris
VP, Controller & Chief Accounting Officer

Well, our tax proposal was exactly that, it was in any sense, to earn our allowed ROE. That's in our tax filing, and the Department of Commerce in their reconsideration for a rate case also asked for a shorter life for Boswell. In addition, in the tax filing that their response was the shorter life of Boswell. So we think it's appropriate that the life of Boswell be taking -- taken up with our tax filing and not part of the rate case, because that's a tax reform issue.

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Paul Thomas Ridzon
KeyBanc Capital Markets Inc., Research Division

And then also at ACE you mentioned that you're looking at 12 potential acquisitions. Should we think about these as kind of PTC's that are expired, kind of like your prior acquisitions? You made, some remaining contract life and is there any opportunity for refurbishments of these potential targets?

Robert J. Adams
Senior VP & CFO

Yes, hi Paul, this is Bob. Yes, In terms of the profile of those acquisitions they would be very similar to the acquisition that we've done historically. So they could have PTC life left in them, several years typically, but coming to the end of the 10-year life, we would certainly look for refurbishment opportunities, in fact some of the ones that we're looking at currently have that opportunity. And so yes, and in terms of returns, you didn't ask about returns, but returns are expected to be very consistent with the types of deals we've done in the past.

Paul Thomas Ridzon
KeyBanc Capital Markets Inc., Research Division

Do you have an inventory of refurbishment eligible parts or are those already earmarked for the 3 projects you're doing?

Robert J. Adams
Senior VP & CFO

They're earmarked for the existing projects we're doing.

Paul Thomas Ridzon
KeyBanc Capital Markets Inc., Research Division

But you would still secure more [MDLs] though for the 80% tax credit, correct?

Robert J. Adams
Senior VP & CFO

That's correct. Yes.

Steven Wayne Morris
VP, Controller & Chief Accounting Officer

Yes, Paul, ACE has turbine supply arrangements with a couple of providers. So there is that opportunity going forward.

Operator

And our next question comes from Chris Ellinghaus from Williams Capital.

Christopher Ronald Ellinghaus
The Williams Capital Group, L.P., Research Division

The discussion on acquisitions seems little bit new. Is -- are you seeing more activity or are you just telling us more at this point?

Robert J. Adams
Senior VP & CFO

So Chris, this is Bob. No it's very much 1 of the 4 planks of our strategy that we talked about, in addition to of course, the PTC strategy that we have. We've been looking at acquisitions, and with a dozen projects there is quite a bit of activity there, so.

Christopher Ronald Ellinghaus
The Williams Capital Group, L.P., Research Division

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I guess, what I'm really saying, has there been an increase in activity or have you really been sort of at this level for a while?

Robert J. Adams
Senior VP & CFO

We've been at this level for a while.

Christopher Ronald Ellinghaus
The Williams Capital Group, L.P., Research Division

Okay. I think Steve was talking about equipment sales timing at U.S. Water. Is that something that you expect to sort of rationalize over the rest of the year?

Robert J. Adams
Senior VP & CFO

Yes, we do.

Christopher Ronald Ellinghaus
The Williams Capital Group, L.P., Research Division

And when you have the weather effect -- at U.S. Water is that something that also, sort of, winds its way through the rest of the seasons?

Robert J. Adams
Senior VP & CFO

Well, yes, of course. This business does better with warmer weather, generally speaking. And so to the extent that warm weather patterns continue, as they have over the last couple of years, we would expect that that would create some potential upside for the company and all things considered, weather would be on plan, so to speak.

Christopher Ronald Ellinghaus
The Williams Capital Group, L.P., Research Division

Okay. And one more thing about the ACE acquisition potential. Are you seeing, because of the winding down of PTC timing that there is a greater pipeline of sellers at this point?

Robert J. Adams
Senior VP & CFO

Not necessarily so. But I would expect that that would be the case as the years unfold here 2019 and 2020.

Christopher Ronald Ellinghaus
The Williams Capital Group, L.P., Research Division

Right. And as far as the necessary equipment, you see more than adequate supply where you shouldn't have any trouble acquiring equipment. Should you make some acquisition?

Robert J. Adams
Senior VP & CFO

Yes, no concerns there.

Operator

And our final question comes from Elizabeth Guynn from Mizuho Investments.

Elizabeth Roi Guynn
Mizuho Securities USA LLC, Research Division

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I just have a quick question. Do you guys expect more equity dilution in 2018?

Robert J. Adams
Senior VP & CFO

So Liz, this is Bob. Let me give you a bit of a picture, but actually both in '18 and '19, where we have a DRIP program, which is our dividend reinvestment program. And typically in a given year, we are issuing between $15 million and $20 million a year. So that's going to be the limit of any equity in '18 and then again in '19 except for the case where we do additional projects at ALLETE Clean Energy or an acquisition at U.S. Water, a larger one.

Elizabeth Roi Guynn
Mizuho Securities USA LLC, Research Division

Okay, great. And then as ACE and the U.S. Water business continue to grow, how do you intend to keep your current regulated and non-regulated business mix, sort of at the equilibrium that it is at right now?

Robert J. Adams
Senior VP & CFO

Well, we've got -- some significant headroom left with regard to our ability to grow the nonreg, we believe. Of course, as you know we -- the ratings -- our credit ratings are important to us, maintaining a strong investment grade rating is important. So we've got some headroom for that growth. And as I stated over time to the extent that there is more growth in the nonreg than regulated and that mix starts to become higher than we like. We will be searching for other regulated opportunities to grow earnings there as well.

Operator

And we do have another question in the queue it's from Kevin Fallon from Citadel.

Kevin Fallon

I just wanted to ask what's baked in guidance for 2018 for Minnesota Power's earned ROE. It looks like from Analyst Day that you guys were expecting an 8.25% ROE is that correct?

Robert J. Adams
Senior VP & CFO

Yes, that is correct, Kevin.

Kevin Fallon

And just make sure, yes, the math is that $20 million pretax added to that would get you to earning a 9.25% at Minnesota Power in 2019?

Robert J. Adams
Senior VP & CFO

That's correct.

Kevin Fallon

And is there any difference between the regulatory ROE and financial ROE? Are there unrecovered costs or something?

Robert J. Adams
Senior VP & CFO

Yes, there is a little bit of unrecovered costs, but it's not significant.

Kevin Fallon

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Like less than 10 basis points not significant or how so?

Robert J. Adams
Senior VP & CFO

Yes, yes, I think that's about right.

Operator

And we do have another question from Paul Ridzon from KeyBanc.

Paul Thomas Ridzon
KeyBanc Capital Markets Inc., Research Division

Just a clarification on Kevin's question. Is that 8.25% consolidated utility or just Minnesota Power?

Robert J. Adams
Senior VP & CFO

It's just Minnesota Power.

Operator

And we have no further questions at this time. So I'll turn the call over to Mr. Hodnik for closing remarks.

Alan R. Hodnik
Chairman, President & CEO

Well, Steve, Bob, and I thank you once again for being with us this morning. Thanks for your investment in ALLETE, and we'll see you all on the road as we get out here in the spring, summer and fall. Thank you very much and have a good day.

Operator
And this concludes today's conference call. You may now disconnect.

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S&P Capital IQ

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Black Hills Corporation NYSE:BKH

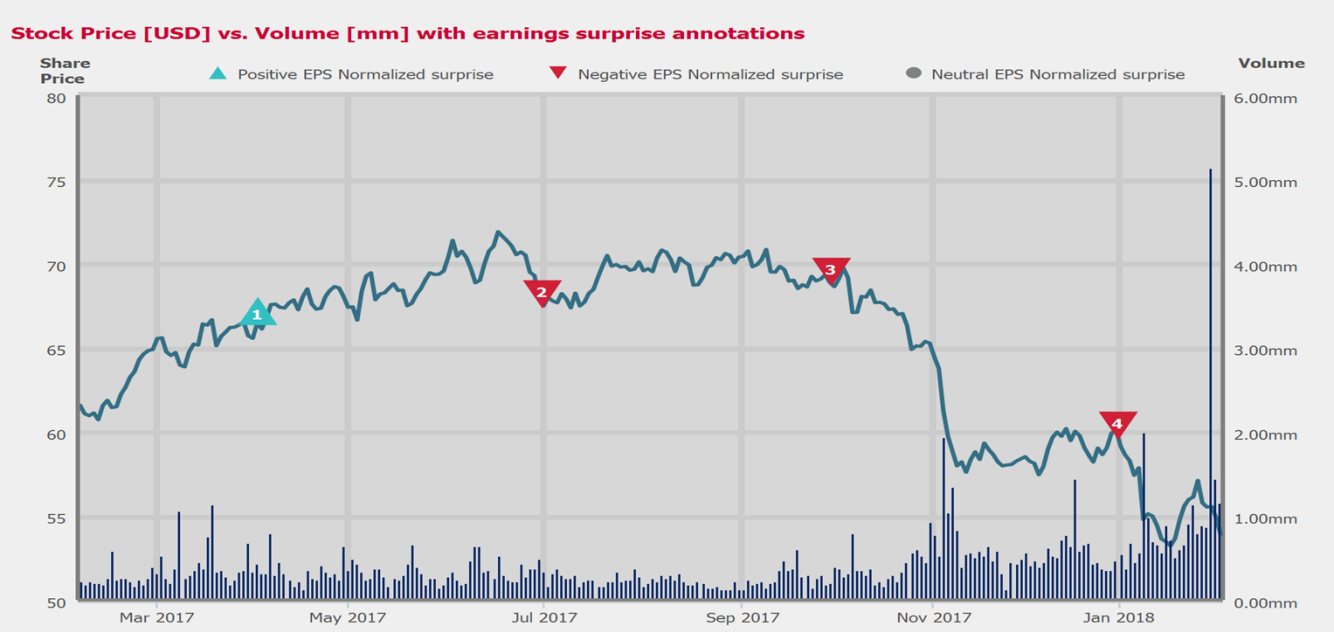
FQ1 2018 Earnings Call Transcripts

Friday, May 04, 2018 3:00 PM GMT

S&P Capital IQ Estimates

	-FQ1 2018-			-FQ2 2018-	-FY 2018-	-FY 2019-
	CONSENSUS	ACTUAL	SURPRISE	CONSENSUS	CONSENSUS	CONSENSUS
EPS Normalized	1.53	1.63	6.54	0.41	3.44	3.45
Revenue	-	-	2.68	-	-	-
Revenue (mm)	560.38	575.40	-	355.36	1756.43	1815.71

Currency: USD
Consensus as of May-01-2018 10:14 AM GMT



- EPS NORMALIZED -

	CONSENSUS	ACTUAL	SURPRISE
FQ1 2017	1.40	1.41	1 0.71 %
FQ2 2017	0.50	0.41	2 (18.00 %)
FQ3 2017	0.55	0.50	3 (9.09 %)
FQ4 2017	1.03	0.98	4 (4.85 %)

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Call Participants

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Presentation

Operator

Good day, ladies and gentlemen, and welcome to the Black Hills Corporation First Quarter 2018 Earnings Conference Call. My name is Brian, and I will be your coordinator for today. [Operator Instructions] As a reminder, this conference call is being recorded for replay purposes.

I would now like to turn the presentation over to Mr. Dave Soderquist, Investor Relations now of Black Hills Corporation. Please proceed, sir.

Dave Soderquist

Good morning. Welcome to Black Hills Corporation's First Quarter 2018 Earnings Conference Call. Leading our quarterly earnings discussion today are David Emery, Chairman and Chief Executive Officer; and Rich Kinzley, Senior Vice President and Chief Financial Officer.

Before we begin today, we would like to note that Black Hills will be attending the American Gas Association Financial Forum starting May 20 in Phoenix, Arizona.

Our presentation materials and webcast information will be posted on our website at www.blackhillscorp.com, under the Investor Relations heading.

During our earnings discussion today, some of the comments we make may contain forward-looking statements as defined by the Securities and Exchange Commission, and there are a number of uncertainties inherent in such comments. Although we believe that our expectations and beliefs are based on reasonable assumptions, actual results may differ materially.

We direct you to our earnings release, Slide 2 of the investor presentation on our website and our most recent Form 10-K and Form 10-Q filed with the Securities and Exchange Commission for a list of some of the factors that could cause future results to differ materially from our expectations.

I will now turn the call over to David Emery.

David R. Emery
Chairman & CEO

Thank you, Dave, and good morning, everyone. I will be starting my comments on Slide 3 of the webcast deck for those of you following along. We'll have a format similar to past quarters. I will give a quick update on the quarter. Rich Kinzley, our CFO, will give the financial update for the quarter. I'll cover forward strategy, and then we'll address questions.

You may have noticed, or will notice as we go through the process this morning, that we've made a few changes to our presentation format. Notably, we've added some more detail to our forecasted capital spending, which should improve some visibility into our future earnings growth. We expect to further enhance those disclosures as the year progresses.

Moving on to Slide 5, first quarter 2018 highlights for our utilities. On the 25th of April, our Colorado Electric utility received approval from the PUC in Colorado to contract with our own IPP subsidiary, Black Hills Generation, to purchase 60 megawatts of wind energy through a 25-year power purchase agreement. That agreement will provide the final amount of renewable resource we need to meet the state's renewable energy standard of 30% by the year 2020.

On April 26, Rocky Mountain Natural Gas, which is our intrastate gas pipeline in Colorado, received a recommended decision from the Colorado Administrative Law Judge, approving a settlement for the rate review it filed in October of last year. That settlement, which is subject to final approval from the Colorado PUC, includes: a $1.1 million increase in annual revenue; importantly, an extension of our safety, system and integrity rider to cover investments that will be made this year through 2021; it includes an

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authorized return on equity of 9.9%; and a capital structure that's 46.6% equity. We expect new rates to be effective June 1, again, pending final approval from the commission.

Moving on to Slide 6, continuing with utilities highlights. During the quarter, our South Dakota Electric utility commenced construction on a $70 million, 175-mile transmission line from Rapid City, South Dakota, to Stegall, Nebraska. That project will be constructed in 2 segments. The first should be placed in service by the end of this year and the second segment by the end of 2019.

Also during the quarter, we continued our efforts to simplify our utility organizational structure by restructuring several of the legal entities that we acquired in 2016 through the SourceGas acquisition. That restructuring resulted in a $49 million tax benefit associated with goodwill that is now amortizable for tax purposes.

Highlights for our Power Generation segment for the quarter. I already noted on April 25, our electric generation subsidiary was selected to provide 60 megawatts of wind to our Colorado Electric utility. That $71 million Busch Ranch II wind project should be constructed and in service prior to the end of 2019.

Moving on to Slide 7, corporate highlights for the quarter. On April 23, our board declared a quarterly dividend of $0.475 a share, which is equivalent to an annual dividend rate of $1.90 per share. That $1.90 per share equivalent rate represents our 48th consecutive annual dividend increase.

On March 8, S&P affirmed its corporate credit rating for Black Hills Corporation at BBB flat, but revised its outlook to positive from stable, which we found encouraging.

Finally, related to discontinued operations, which is our Oil and Gas segment. As of yesterday, we'd executed agreements to sell -- or had closed on sales transactions for about 96% of our oil and gas properties, as measured by gross well count. Now we expect to sell our remaining assets prior to the end of the quarter.

Slide 8 provides a reconciliation of first quarter, net income from continuing operations as adjusted compared to the first quarter of 2017. The most notable change being improved performance at our Gas Utilities. Rich will provide more detail in his financial update, which I'll turn it over to Rich to cover financials.

Richard W. Kinzley
Senior VP & CFO

Very good. Thanks, Dave, and good morning, everyone. As Dave touched on, we delivered solid first quarter financial performance. With help from favorable weather, year-over-year, our natural gas utilities delivered strong financial results in Q1, demonstrating the benefits of our diversified utility portfolio and the 2016 SourceGas acquisition.

I'll jump in on Slide 10, where we reconciled GAAP earnings to earnings as adjusted, a non-GAAP measure. We do this to isolate special items and communicate earnings to better represent our ongoing performance. This slide displays the last 5 quarters and trailing 12 months as of March 31, 2018 and 2017.

As detailed on the slide, we experienced special items not reflective of our ongoing performance in each of the past 5 quarters. The first special item is acquisition-related expenses associated with the SourceGas acquisition and integration. We completed our integration work in 2017 and don't have that adjustment in 2018 or forward.

The second special item relates to income taxes and is predominantly the result of federal income tax reform. The corporate tax rate change from 35% to 21% beginning in 2018 required a revaluation of our deferred asset -- deferred tax assets and liabilities on December 31, 2017, resulting in a $0.21 EPS benefit in the fourth quarter of 2017. Given additional information in Q1, certain estimates impacting the revaluation have been updated, resulting in a Q1 charge of $2.3 million or $0.04 of EPS.

The largest special item in Q1 2018, also related to income taxes. As Dave noted, as part of our effort to simplify our legal organization, in Q1, we restructured certain entities as part of the 2016 SourceGas

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acquisition. The restructuring increased goodwill that is amortizable for tax purposes, resulting in an associated deferred tax benefit of $49 million or $0.91 of EPS. These items are not indicative of our ongoing performance and, accordingly, we reflect them on an as-adjusted basis.

Our first quarter as-adjusted EPS was $1.63 compared to $1.44 for the first quarter last year. The earnings uplift comparing Q1 this year to Q1 last year was primarily driven by a colder winter heating season at our Gas and Electric Utilities compared to a mild winter last year. We estimate mild weather last year, as compared to normal, negatively impacted Q1 2017 EPS by $0.09. This year, we estimate that colder weather, compared to normal, positively impacted Q1 2018 EPS by $0.05.

Slide 11 is a new slide we've added to our investor materials to provide additional transparency related to year-over-year comparisons. The waterfall chart illustrates major drivers that comprise the differences from Q1 2017 to Q1 2018. All amounts on the chart are net of tax. Again, you'll note weather was a large positive driver year-over-year, especially at the Gas Utilities. We recorded a revenue reserve in Q1 2018 at the Gas and Electric Utilities due to tax reform as we expect to pass the benefit of the lower corporate tax rate on to customers through reduced bills. However, this has no impact on net earnings due to the lower income tax rate as a result of tax reform. Dave will touch on this more in a bit, but in short, we continue to work with our regulators in each of our states to pass the tax benefit from tax reform to our utility customers. You can also see we did a good job managing O&M on a consolidated basis, with limited O&M increases year-over-year.

Slide 12 displays our first quarter income statement. Gross margin was flat year-over-year despite the revenue reduction related to tax reform that I noted a moment ago. Operating expenses and DD&A increased modestly comparing Q1 2018 to Q1 2017, primarily due to typical operating expense increases and incremental plant investments. Operating income was down for the quarter compared to the prior year, again, mainly due to revenue reserves related to tax reform, which is offset by reduced income tax expense below the operating income line.

Moving below the operating income line. Interest expense increased slightly year-over-year due to higher interest rates on our variable-rate short-term debt. The most significant change, comparing Q1 2018 to Q1 2017, is on the income tax line. You'll note the $26 million income tax benefit recorded in Q1 2018 despite $113 million of pretax income. This resulted from the legal reorganization we mentioned already.

The effective tax rate, after adjusting out the special items I noted on Slide 10, is 18.9% in Q1 2018 compared to 29.6% in Q1 2017. The lower effective rate this year was driven by tax reforms corporate rate reduction.

Moving to the as-adjusted income from continuing operations line, we generated $88 million for the quarter compared to $79 million for the same quarter last year, a 12% increase. You'll note our Q1 2018 diluted share count decreased compared to Q1 2017. This was due to the application of the treasury stock method related to the unit mandatory securities we issued in late 2015 to help fund the SourceGas acquisition. Until these securities convert to equity in November of this year, we're required to apply the treasury method of accounting, whereby we include a portion of the shares in our diluted share count.

The number of shares we include is based on the average daily closing price of our stock during the reporting period. Our average share price was lower in Q1 2018 compared to Q1 2017.

So in Q1 2018, we added approximately 700,000 shares to our diluted share count, compared to approximately 1.6 million additional shares in Q1 2017.

As I noted in our year-end earnings call on February 2, we're assuming approximately 56 million weighted average shares in our full year 2018 guidance, as we will have approximately 60 million diluted shares beginning November 1, after the conversion occurs. Considering the increase in as-adjusted net income and reduced share count, as-adjusted EPS grew $0.19 or 13% from the same quarter last year.

I'll now discuss each business segment. Slide 13 compares our Electric and Gas Utility segment's Q1 2018 gross margin and operating income compared to Q1 2017. Our Electric Utilities operating income decreased $7.3 million in the first quarter of 2018 compared to first quarter 2017.

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Electric Utilities gross margin decreased $1.4 million quarter-over-quarter, driven by a $6.1 million revenue reserve related to tax reform, partially offset by higher margins from investments in transmission, favorable weather and higher non-energy revenues.

Operating expenses, including depreciation, were $5.9 million higher for the first quarter of 2018 compared to the first quarter of 2017, as a result of increased vegetation management and outage-related expenses as well as increased property taxes and depreciation associated with rate base investments.

Moving to the right slide of Slide 13. Our Gas Utilities reported an increase of $3.4 million in operating income comparing Q1 2018 to Q1 2017. Gross margins were favorable by $4.2 million quarter-over-quarter, as cold weather added $9 million of incremental margin year-over-year. Heating degree days were 2% higher than normal in Q1 2018 compared to 13% below normal for Q1 2017. Customer growth and capital recovery rider mechanisms added approximately $4 million to margins year-over-year. These increases were partially offset by tax reform-related revenue reserves of $9 million.

Operating expenses were nominally higher compared to the prior year, reflecting strong cost management of the Gas Utilities. As I noted earlier, the unfavorable impact of operating income -- to operating income from tax reform at both the Electric and Gas Utilities is offset by lower income tax expense and is earnings neutral.

On Slide 14, you see that Power Generation operating income increased $400,000 comparing Q1 2018 to Q1 2017, primarily from reduced sales volume under our power purchase agreements. The Power Generation segment continued to realize strong contract availability from its generating units and continued its strong earnings and cash flow contributions. Also on Slide 14, you'll see in the first quarter of 2018, our Mining segment had a $1 million operating income increase compared to first quarter 2017.

For the quarter, revenue was $600,000 higher, primarily from higher tons sold in 2018. On the O&M side, we decreased cost by $400,000. Our mine continues to perform at a high level, with sales almost entirely to on-site [9-mile plants] and roughly half our sales based on a cost-plus pricing methodology.

Slide 15 shows our capitalization. At March 31, our net debt-to-capitalization ratio was 64.1%, a decrease of 190 basis points from year-end. This reduction was driven by the increase in retained earnings due to our solid first quarter earnings as well as by strong first quarter cash flows that allowed us to reduce our total debt from year-end. Our $299 million of unit mandatory securities are reflected as debt on our balance sheet until the units convert to equity on November 1 this year. After conversion, we expect our debt -- net debt-to-capitalization ratio to decline below 60%. While we may need to increase our short-term borrowings from time-to-time over the course of 2018 and 2019 to fund our currently forecasted capital expenditures, we don't anticipate the need to issue any equity to fund these activities. If additional capital investment opportunities emerge, we have our At-the-Market equity program available if the need to issue any equity arises.

Slide 16 shows our debt maturity schedule. The unit mandatories require us to remarket the debt noted as a 2028 maturity on the schedule, which we will do during the second half of this year. We're also evaluating options for the 2019 and 2020 maturities.

Slide 17 shows our investment-grade credit rating. As Dave noted, during the first quarter, S&P affirmed our BBB credit rating and upgraded the outlook to positive. We're committed to maintaining our strong investment-grade credit ratings, and our forward forecasted metrics support those ratings.

On Slide 18, we're reaffirming our 2018 earnings guidance of $3.30 to $3.50 per share based on the assumptions previously provided on February 2, 2018.

I'll turn it back to Dave now for his strategic overview.

David R. Emery
Chairman & CEO

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All right. Thank you, Rich. Moving on to Slide 20. We group our strategic goals into 4 major categories: profitable growth, valued service, better every day and great workplace, with the overall objective of being an industry leader in all we do.

On Slide 21. From a strategy execution perspective, we're focused on delivering strong long-term total shareholder returns. We plan to accomplish that by achieving a long-term EPS growth rate that's above the industry average, targeting a 50% to 60% dividend payout ratio, while still retaining the flexibility to increase that dividend during periods of slower EPS growth and continuing our track record of 48 consecutive annual dividend increases.

On Slide 22. We're currently in the process of transitioning our earnings growth drivers, from a largely acquisition- and integration-focused strategy over the last year or so with the SourceGas acquisition, back to a more traditional utility growth approach. In the near term, this year and next year, we expect slower earnings growth since we're entering test years in preparation for rate review filings or actually commencing those rate review filings in some of our jurisdictions. We do have 3 active rate review processes currently in process right now.

Over the long term, starting in 2020 and beyond, we expect higher earnings growth expectations, driven by strong capital investments to meet our customer needs, continued focus on standardization and efficiency improvements and back to more regular rate review filings.

Slide 23. As we focus on delivering long-term shareholder value, our fuel and service territory diversity reduces our business risk and drives more predictable earnings.

Slide 24. Our utility acquisitions over the years have created a much larger transmission and distribution system network, both on the electric and the gas side of the business. With that increase in size comes increased opportunity for investment to serve a much larger customer base.

Moving on to Slide 25. Strong capital spending has in the past and will continue to drive much of our earnings growth. We plan to invest almost $2.3 billion over the next 5 years to better serve our 1.25 million utility customers. And that level of investment far exceeds depreciation contributing to earnings growth.

Slide 26, which is a new look, provides a detailed capital spending forecast for our Gas Utilities, including breakouts by state, investment type and recovery mechanisms for a full 5 years compared to the 3 years that we previously disclosed.

Slide 27 provides a similar capital spending detail for our Electric Utilities.

Moving on to Slide 28. This slide provides a regulatory update for our utilities, highlighting the status of our active rate review filings and our federal income tax reform dockets by state. You'll notice that we've completed the process of determining customer benefits for federal income tax reform in both Iowa and Kansas, and either have started to reflect those changes on customer bills, as is the case in Iowa, or are planning to beginning in -- or Kansas, I'm sorry, and then planning to do that beginning in July for the state of Iowa.

I've already noted the other key regulatory updates, with one exception. And that is on April 30, we received an order from the Denver District Court regarding our appeal of the Colorado Public Utility Commission's prior decision on our 2016 rate review for Colorado Electric. There are several issues addressed in the ruling, some positive and some negative for Black Hills. Most notably, we're very disappointed that the court affirmed the commission's decision related to the rate treatment of the new gas turbine generator we constructed in Colorado. The PUC in that 2016 rate decision assigned a lower return on investment for that turbine than for any of our other utility assets in Colorado. The turbine was built in response to the Colorado Clean Air-Clean Jobs Act, a law passed in Colorado that was intended to provide an incentive to utilities to retire their coal fire generation before the end of its useful life and replace it with cleaner, more modern generation. Now for the commission to assign a lower return on investment for the new generation, after we built it in good faith and in compliance with the Clean Air-Clean Jobs Act, this is very troubling, and the fact that the court upheld that is even more troubling. And frankly, we feel it's contrary to the intent of the Colorado Clean Air-Clean Jobs Act. We're currently

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evaluating the impacts of the court order on our business and considering our next steps in the legal process.

Moving on to Slide 29. Now we're extremely proud of our track record of annual dividend increases that I mentioned earlier, including stronger increases the past several years, reflecting our confidence in strong future earnings growth and cash flows.

As I noted earlier, we have the flexibility to use larger dividend increases during periods of slower earnings growth to help deliver solid total shareholder returns. Even after relatively strong dividend increases during the past few years, we're still well within our targeted 50% to 60% dividend payout ratio range.

Moving on to Slide 30. Now we focus every day on operational excellence. We continue to make great progress, improving our safety performance, and also continued to consistently demonstrate our power plant availabilities, which are among some of the best in the industry.

On Slide 31, we note that we've created a new corporate responsibility report, which is available on our website. We encourage you to check that out.

And finally, on Slide 32. This is our scorecard for 2018. This is our way of holding ourselves accountable to you, our shareholders, for our accomplishments in our key strategic objectives.
Now that concludes our remarks. We'd be happy to entertain any questions.

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Question and Answer

Operator

[Operator Instructions] And our first question will come from the line of Julien Dumoulin-Smith with Bank of America Merrill Lynch.

Julien Patrick Dumoulin-Smith
BofA Merrill Lynch, Research Division

So perhaps, just to come back to a few things you said. First off, on the wind award. Just curious, how do you think about earnings profile of that asset, specifically on the latest one? But more broadly, do you anticipate participating perhaps even outside of your service territory for these kinds of projects more strategically, i.e., more contract? And I suppose this is the latest example, so I'd just be curious.

David R. Emery
Chairman & CEO

Yes. I would categorize this one. Obviously, this is an investment from our IPP subsidiary. I would categorize the earnings from that as probably consistent with how you would look at an IPP project, that is, it's financed with a little more debt than you would expect from a utility capital structure. And then also, the returns would be consistent with an IPP-like return. As far as whether we would do this outside of our existing service territories, they're not -- I would say, the answer is yes, but on a limited basis. I think there would have to be a very compelling strategic reason for us to do so, whether that's a relationship with an existing wholesale customer or something like that. We don't have any aspirations of running out and being a full-blown competitor in the IPP business. That's not our strength. But I do think there are certain circumstances where it may make sense for us to do this to for others. They will be fairly few and far between, however.

Julien Patrick Dumoulin-Smith
BofA Merrill Lynch, Research Division

All right. And just on -- in terms of, like, the net income profile of the latest wind investment, would you characterize it as a premium or discount to the traditional utility returns?

David R. Emery
Chairman & CEO

Well, I think the return would be probably comparable, but the capital structure's significantly different with less equity, right? And then as -- consistent with wind projects and other renewable projects, a lot of the earnings are really driven by production tax credits, so they show up below the operating income line.

Richard W. Kinzley
Senior VP & CFO

And I'd add one thing to that, Julien. That was a competitive process, and there were a lot of bids. It was vigorously competitive so we did have to be aggressive to win that bid.

Julien Patrick Dumoulin-Smith
BofA Merrill Lynch, Research Division

Got it. All right. Understood. And actually, let me turn back to you, real quickly here, Rich. In terms of the comments you made on the call around capital spend and the potential need for equity, just can you frame that a little bit in terms of what sort of -- under what circumstances you would see that at this point in time? And then secondly, I suppose related to that, you provided a little bit more of an extensive view on your CapEx here out to '22. Can you talk about some of the other big puts and takes that might materialize here in your forecast given now that we've got the wind one out?

David R. Emery

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Chairman & CEO

Yes. From Q1 to Q2, you can see the difference in our CapEx schedule is the additional wind project. We added $11 million to this year's capital and $60 million the next year. We're still comfortable that after the convert, we're going to be well below 60%. When that converts, that'll get our debt-to-total cap down below 60%, and our cash flow should keep us there through the end of 2019. And then if you look post 2019 at that CapEx schedule, we should remain comfortably there. If additional large projects come up, we may need to issue some equity. That's where I'd leave that, Julien.

Richard W. Kinzley
Senior VP & CFO

Yes. And I'd say that story is consistent with what we've talked about in the past, Julien. We've said we have fairly aggressive capital spending outlook going forward, but we expect to finance that with internal cash flows and debt, absent any big special projects that might get added. And that is why we have kept our At-the-Market equity issuance program active, just in case we may have one of those projects. But we would only use that in the event that we'd have some additional CapEx that is not on our current schedule.

Julien Patrick Dumoulin-Smith
BofA Merrill Lynch, Research Division

But is there any other large capital project, whether in procurement now or bidding, et cetera, that we should be paying attention to? It doesn't sound like it.

David R. Emery
Chairman & CEO

Well, there are several in the works, but not mature enough to the point that we're ready to talk about specific projects. I mean, we're always looking at some renewable projects for our Electric Utilities, pipelines for our Gas Utilities, transmission lines we've talked about, things like that. And we have several of those that we're looking at and studying and, potentially, would integrate into our forward plans, just not mature enough to actually file a certificate of public convenience in necessity or something that would say we're really ready to propose yet.

Operator

And our next question will come from the line of Michael Weinstein with Crédit Suisse.

Michael Weinstein
Crédit Suisse AG, Research Division

I may have missed this, but in light of the court decision now, I mean, can you still file for rehearing? I think you can, right? I mean, they should I'd think the -- and from my understanding, that this -- the commission had suspended the rehearing or canceled it, waiting for the court decision, right? So is it possible that they might take it back up again anyway?

David R. Emery
Chairman & CEO

Yes. We've got several options and we're evaluating all those. One is, of course, another level of appeal, which we certainly could do. The other one is we could basically elect to either go back and ask the commission to rehear that or frankly, include it in another rate case. All those options are on the table. And frankly, having just received that ruling earlier this week, we're still in the process of discussing what those options are and which ones would be the best to pursue at this point in time. But they're all on the table.

Michael Weinstein
Crédit Suisse AG, Research Division

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Yes. I guess -- I mean, my other interest there is that in light of the approval for Busch Ranch and also the Rocky Mountain gas pipeline ALJ recommendation, those decisions, do you think they bode well for a possible rehearing despite the court decision?

David R. Emery
Chairman & CEO

It's really hard to say and hard to speculate. I think we've been pleased working in relationship with the commission recently and we hope that continues.

Michael Weinstein
Crédit Suisse AG, Research Division

Okay. Can you give any color on the other discussions on the pass back of tax savings beyond Iowa and Kansas?

Richard W. Kinzley
Senior VP & CFO

Well, they're all in various states of process. So the Colorado Rocky Mountain Natural Gas pipeline, that settlement includes the impacts of tax reform. Our active rate reviews in Northwest Wyoming and in Arkansas, when they get completed, will include the results of tax reform. And then all of the others are at various stages in the process, from very early to well underway. Our tact in most of those -- and it's going to be a commission-dependent decision state-by-state, but we've taken the position that we think it's best for customers to go back to their most recent rate case and just compute the difference on the tax rate and start collecting -- or stop collecting that difference from customers going forward and, of course, refund it back to the effective date of the tax rate change. That's not going to happen in every state, we don't think. Some of them are asking us to look at what's the current impact rather than the impact back to the most previous rate case. But all are progressing, and we're comfortable and happy, frankly, with the progress we're making. Some will be a little slower, though.

Operator

[Operator Instructions] And I'm showing no further questions over the phone lines. Mr. David Emery, please proceed with closing remarks.

David R. Emery
Chairman & CEO

All right. Thank you. Well, thanks for your time and attention this morning, everyone. We appreciate you attending our Q1 earnings call. And for those of you who are going to be at the AGA Financial Forum, we look forward to visiting with you there. Have a great day and a great weekend. Thank you.

Operator
Ladies and gentlemen, thank you for your participation on today's conference. This concludes the presentation. You may now disconnect. Good day.

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Hawaiian Electric Industries, Inc. NYSE:HE

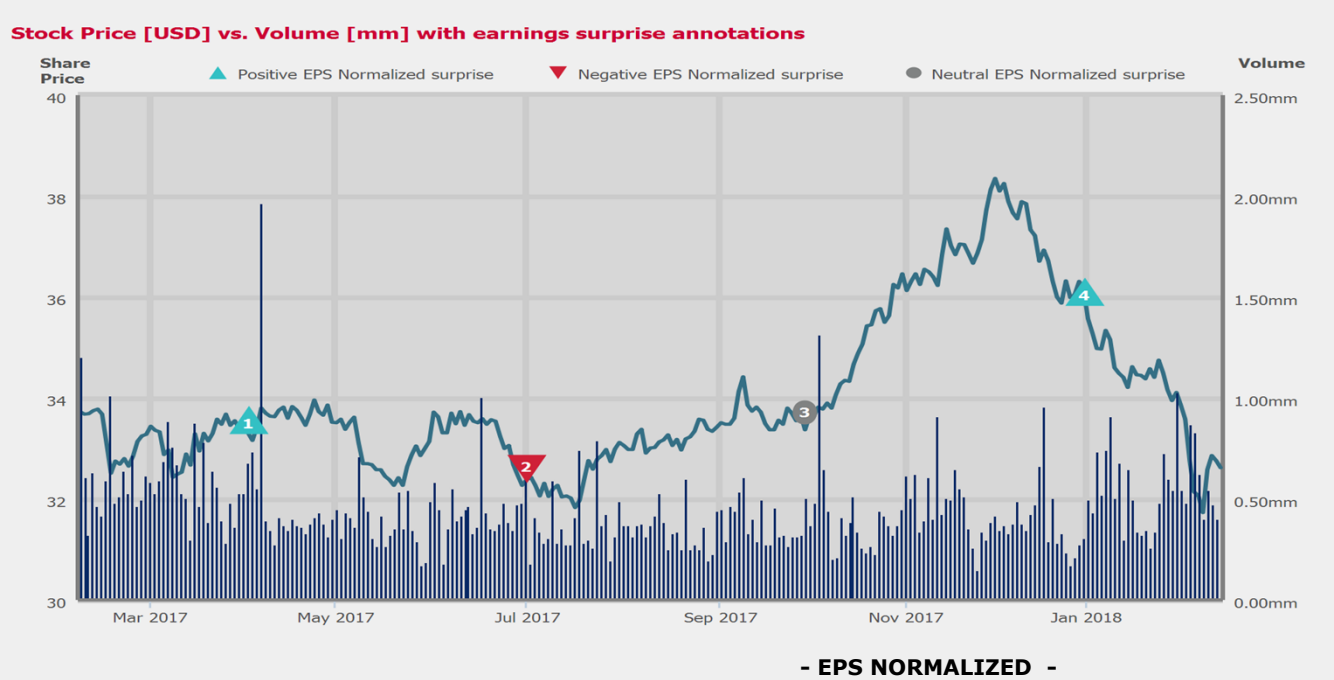
FQ1 2018 Earnings Call Transcripts

Thursday, May 10, 2018 5:30 PM GMT

S&P Capital IQ Estimates

	-FQ1 2018-			-FQ2 2018-	-FY 2018-	-FY 2019-
	CONSENSUS	ACTUAL	SURPRISE	CONSENSUS	CONSENSUS	CONSENSUS
EPS Normalized	0.38	0.37	▼(2.63 %)	0.44	1.91	2.05
Revenue	-	-	▲12.02	-	-	-
Revenue (mm)	576.59	645.87	-	607.86	2559.55	2609.19

Currency: USD
Consensus as of May-01-2018 10:26 AM GMT



- EPS NORMALIZED -

	CONSENSUS	ACTUAL	SURPRISE
FQ1 2017	0.28	0.31	▲1 10.71 %
FQ2 2017	0.39	0.36	▼2 (7.69 %)
FQ3 2017	0.55	0.55	3 0.00 %
FQ4 2017	0.41	0.43	▲4 4.88 %

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Presentation

Operator

Good day, and welcome to the Hawaiian Electric Industries, Inc. First Quarter 2018 Earnings Conference Call. [Operator Instructions] Please note, this event is being recorded. I would now like to turn the conference over to Julie Smolinski, Manager, Investor Relations. Please go ahead.

Julie Smolinski
investor relations contact

Thank you, and welcome to Hawaiian Electric Industries' First Quarter 2018 Earnings Conference Call.

Joining me this morning are Connie Lau, HEI President and Chief Executive Officer, and Chairman of the Board of Hawaiian Electric Company and American Savings Bank; Greg Hazelton, HEI Executive Vice President and Chief Financial Officer; Alan Oshima, Hawaiian Electric Company President and Chief Executive Officer; and Rich Wacker, American Savings Bank President and Chief Executive Officer; as well as other members of senior management.

Connie will provide an overview, followed by Greg, who will update you on Hawaii's economy, our results for the first quarter and our outlook for the remainder of the year. Then, we will conclude with questions-and-answers.

During today's call, we'll be using non-GAAP financial measures to describe our operating performance. Our press release and webcast presentation are posted on HEI's Investor Relations website, and contain reconciliations of these measures to the equivalent GAAP measures.

Forward-looking statements will also be made on today's call. Factors that could cause actual results to differ materially from expectations can be found on our webcast slides, our filings with the SEC and on the HEI website.

I'll now ask our CEO, Connie Lau, to begin with an overview.

Constance Hee Lau
President, CEO & Director

Thank you, Julie, and aloha to everyone. As we get started today, I'd like to provide an update on the lava and related seismic activity on the island of Hawaii. Our thoughts are with those who have lost their homes and with those who have had to evacuate. Our utility on Hawaii Island has been working with authorities to ensure public safety and sufficient power supply, and our teams from Oahu and Maui County have been providing assistance as well. I want to acknowledge the hard work of our teams, and we thank them for their dedication and support of one another and of our customers.

While this is still a developing situation, at this time, we expect that the lava and seismic activity will not have a material impact on our company. The affected area is about 10 square miles on the southeastern part of Hawaii Island, and while several hundred residents have evacuated and some have indeed lost their homes, significant utility infrastructure has not been destroyed. We are also assessing earthquake impacts to facilities and have not found widespread damage to date.

On the bank side, total loan exposure in the lava-affected area is limited. The area is not densely populated and American ceased making new loans in that area after lava activity in 2014.

Now turning to the results for the first quarter. We are pleased to report solid earnings from both our bank and utility, in line with our expectations for the year and resulting in consolidated net income of $40 million and consolidated earnings per share of $0.37. This includes American's highest ever quarterly earnings. Greg will walk through our results in more detail in a few minutes.

With respect to the utility, in the first quarter, we've made progress on a number of important initiatives. As we complete our return to a triannual rate case cycle for our 3 utilities, we are providing the net

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benefits of tax reform to our utility customers. These benefits are reflected in adjusted interim rates for our Oahu and Hawaii Island customers that began this spring. And our Maui County utility has filed a reduced 2018 RAM adjustment mechanism request and also reduced its 2018 rate case request to reflect tax reform, with an interim decision expected in August.

We filed our electrification of transportation road map in March, driving near and long-term actions to create a clean energy future and reduce dependence on imported fuel oil for both transportation and electricity. Transportation accounts for nearly 2/3 of fossil fuel brought to Hawaii, so addressing the transportation sector is essential to reducing Hawaii's carbon footprint and increasing our island state's energy security. At our current pace, we're on track to meet or exceed our state's next renewable milestone of 30% by 2020.

We've recently seen the groundbreaking of several large solar projects, including our own 20-megawatt photovoltaic project at Joint Base Pearl Harbor-Hickam. Through our renewable generation RFPs, we are providing a platform for third party development of approximately 300 megawatts of additional renewables. And last week, we filed applications to add 2 good-scale batteries on Oahu, to help integrate more renewables while improving resilience and [indiscernible]

Finally, as many of you know, last month, our commission opened a proceeding and our Governor signed into law a legislation to evaluate and implement performance-based regulation, or PBR. We have advocated for this PBR for some time and already have some elements of it in place such as decoupling and performance incentives for reliability, customer service, renewable energy procurement and demand response. In its docket, the commission indicated it seeks to build on the existing regulatory framework rather than make wholesale changes.

We see PBR as an opportunity for our company as incentives may be approved to provide revenue opportunities without completely changing cost of service regulation. The recently established performance incentives for our renewable generation RFPs are a good example of this, providing the potential for the utility to earn by successfully adding competitively priced contracted renewables under our new PPA framework.

With the Commission's acceptance of our power supply improvement plan last year and approval of our grid modernization strategy earlier this year, and now our recently filed electrification of transportation road map, we now have in place comprehensive plans for reaching our 100% clean energy goal and the framework for measuring performance as we move forward. We believe the commission has outlined a collaborative, deliberative approach for developing PBR elements to advance Hawaii's goals while maintaining a financially stable utility and a safe, reliable and resilient grid, and we look forward to participating in the process over the next 2 years.

Turning to the bank. As I mentioned, American had the highest quarterly net income in its history, delivering well on fundamentals like net interest margin and deposit and loan growth, while benefiting from lower tax rates due to tax reform. The lower tax expense also allowed American to meaningfully increase wage rates for its employees at entry-level and lower wage positions starting this year.

American's new Honolulu campus remains a key focus for the bank and construction is well underway. Our bank team looks forward to consolidating its core management and operations teams into a single, new innovative space later this year, resulting in greater efficiencies for the bank and its customers.

Moving to Pacific Current. In the first quarter, our new subsidiary announced its second investment, a solar plus storage project that will provide 8.6 megawatts of solar capacity and 42.3-megawatt hours of storage capacity on the islands of Maui and Oahu at 5 University of Hawaii campuses. The facilities are in construction phase and are expected to be operational in 2019. We expect this project to be accretive to earnings in its first full year of operation.

This project is a great example of Pacific Current's approach of partnering with others and helping bring together Hawaii-based resources to advance our state's clean energy and sustainability goals. Our initial project, Hamakua Energy, is helping to fund Pacific Current's startup cost, and we are focused on building out Pacific Current's organization and management team.

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I'll now ask Greg to cover Hawaii's economy, our first quarter financial results and company outlook for 2018. Greg?

Gregory C. Hazelton
Executive VP & CFO

Thanks, Connie. The overall health of Hawaii economy has remained sound as expansion continues, with ongoing strength in tourism and real estate and the labor force near full employment. Unemployment remains very low, below 3% since mid-2016. At 2.1% in March, it is now the lowest on record for the state and continues to be below the national rate. The increasingly tight labor market could begin to spur wage growth, which consistent with the rest of the country, has lagged unemployment levels.

A key area of employment growth has been the tourism industry, which continued a lengthy expansion that began in 2010. The industry has built on its record-setting 2017 results, seeing visitor arrivals and spending continue to rise.

The outlook is positive. At current rates, we are heading toward another record year for arrivals approaching 10 million visitors. Airlines have increased scheduled air seats to Hawaii, particularly from the western U.S. And Southwest is entering the market with service from the mainland as well as interisland.

Hawaii real estate has remained strong. Year-to-date April, both sales volume and prices continued to rise due to high demand. As of April, the median sales price for single-family homes rose 4.6% from the prior year to $774,000, and condos were up 7.5% to $425,000. Overall, the Hawaii economy is performing well with local and international conditions supporting the positive outlook.

Turning to our financial results, as shown on Slide 6. First quarter earnings per share were $0.37 per share, compared to $0.31 per share for the first quarter of 2017. We realized earnings improvement at both the utility and bank, offset in part by higher holding company losses, which were expected due to lower tax benefits on expenses and from a reduced federal tax rate and increased interest expense.

The holding company segment currently includes -- also includes Pacific Current, currently with 2 investments, Hamakua Energy, which has operated well and according to plan and contributed positively to earnings. However, our UH investment in February incurred transaction costs, which offset in part the earnings contributions at Hamakua.

Turning to Slide 7. HEI's consolidated ROE for the last 12 months was 8.2%, with contributions of 6.9% from the utility and 11.8% from the bank. Excluding the onetime impacts of tax reform recorded in the fourth quarter of 2017, HEI's core consolidated ROE for the last 12 months was 8.9% and the utility core ROE was 7.4%.

Utility results for the March 2018 LTM period reflect the impact of the 2017 expiry of the RAM settlement agreement as well as our ongoing transition back to a triannual rate case cycle and reset of base rates after no base rate increases for 6 years.

The March 2018 LTM results include 7 months of interim rates at Hawaii Electric Light and 1.5 months of interim rates at Hawaiian Electric, our largest utility. We expect ROE improvement from continuation of these interim rates throughout the year -- throughout the rest of the year as well as the upcoming interim decision on a Maui Electric rate case in August.

At the bank, we realized an increase in ROEs for the last 12 months, primarily driven by tax reform, continued low-cost funding and strengthening yield on earning assets. We expect further ROE expansion as we progress through the year. The bank's annualized ROE for Q1 2018 was 12.58%.

On Slide 8, utility earnings were $27.5 million in the first quarter of 2018 compared to $21.5 million in the first quarter of 2017. The most significant net income drivers were as follows: $11 million higher RAM revenues in 2018, primarily due to lower revenues in the first quarter of 2017 because of the return in 2017 to reporting Oahu RAM revenues for accounting purposes on a lagged basis beginning June 1, 2017 instead of on a calendar year basis due to the expiration of a 2013 settlement agreement; $5 million of interim rate relief for Hawaiian Electric's 2017 year interim rates effective mid-February and a full year of

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benefits from Hawaiian Electric Light 2016 test year interim rates, which became effective in August 2017; and $1 million higher allowance for funds used during construction mainly from the Schofield Generating Station to be completed in the second quarter.

These amounts were partially offset by $7 million higher O&M expenses compared to 2017, primarily due to the reset of pension costs as part of rate case interim decisions, higher overhaul costs for generation, a write-off of certain smart grid costs that were incurred before the approval of a revised grid modernization strategy and a onetime expense -- rent expense adjustment for an existing substation land lease, partially offset by an additional reserve for environmental costs in 2017. Also, $2 million higher depreciation expense for increasing investments in integration of more renewable energy, improved customer reliability and greater system efficiency, and $2 million lower net income, primarily representing the difference between first quarter 2018 accrued tax reform net benefits to customers and our first quarter tax savings.

Turning to the bank on Slide 9. In the first quarter of 2018, American saw its highest quarterly net income ever at $19 million, $3 million -- $3.1 million higher than the first quarter of 2017 and $2.1 million higher than the fourth or linked quarter. Compared to the linked quarter, the increase was primarily driven by higher net interest income, which was mainly due to higher yields on green assets and strong deposit growth that funded increases in the investment and retail portfolios.

The first quarter also included $3 million in benefits from lower federal tax rates compared to the onetime tax benefit of $1.7 million recognized in the linked quarter.

In the linked quarter, American awarded $1 million to its employees through a $1,000 cash bonus. American's wage rate increase for entry-level and lower-wage positions beginning in 2018 increased compensations cost for the quarter and the year.

Compared to the first quarter of 2017, the $3.1 million higher net income was primarily driven by higher net interest income, partially offset by lower noninterest income.

Noninterest expense in the first quarter of 2018 was higher than the same period in 2017 due to higher compensation expense and benefit expense, reflecting the wage increases mentioned a moment ago, along with higher performance-based incentives and annual merit increases, substantially offset by the impact of lower taxes.

On Slide 10, we see American's solid profitability reflected in increases in both its return on assets and net interest margin. We achieved a return on assets of 112 basis points, exceeding our 2018 annual target of over 110 basis points.

Our net interest margin was 3.76%, within our guidance range of 3.7% to 3.8%. Our strong interest -- net interest margin is primarily due to higher yields on interest-earning assets and strong low-cost deposit growth that funded earning asset growth in the investment and retail portfolio.

On Slide 11, our net interest margin of 3.76% in the first quarter of 2018 was 8 basis points higher than the linked quarter. Our interest-earning asset yield increased 10 basis points from the linked quarter, primarily due to increases in yields in the investment and loan portfolios. And our liability costs at 23 -- remained low at 23 basis points although it increased by 2 basis points compared to the linked quarter as deposit costs have increased in the rising interest rate environment, primarily due to term certificates.

On Slide 12, net interest income was approximately 3% higher compared to the linked quarter, driven by low-cost deposit growth that funded our investment growth as well as higher yields on loans.

Noninterest income of $13.4 million was lower than linked quarter, mainly due to lower net debit charge -- interchange fee income, resulting primarily from a reclassification of expenses due to a new accounting standard.

Total loans as of the quarter end increased by $71 million at a 6.1% annualized growth rate, primarily driven by increases in commercial and commercial real estate loans of $63 million. We expect to meet our target of low to mid-single-digit earning asset growth for the year.

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Our deposit growth in the first quarter was 12.8% annualized, including approximately $100 million in repurchase agreements that were transferred into deposit accounts. Excluding such transfers, deposit growth was 6%.

Credit quality remains sound due to prudent risk management and a healthy local economy. Our residential portfolio remains very clean, consumer unsecured credit quality is in line with expectations, and the commercial and commercial real estate portfolios are stable with improving trends.

First quarter 2018 provision for loan losses included reserves for loan growth. Additional reserves for the consumer loan portfolio were partially offset by the release of reserves for the commercial loan portfolio due to a recovery on a previously charged-off commercial loan and improved credit quality.

Our net charge-off ratio was 28 basis points for the quarter of -- first quarter of 2018 compared to 26 basis points in the linked quarter.

Nonaccrual loans as a percentage of total loans receivable held for investment was 0.53% compared to 0.51% at the end of the linked quarter. The allowance for loan losses of $54 million was 1.14% of outstanding loans at the quarter end compared to 1.15% in the linked quarter and 1.19% as of the prior year -- prior quarter.

Slide 14 illustrates American's continued attractive asset and funding mix relative to our peer banks. American's March 31, 2018 balance sheet is compared to the last available data for our peers from the fourth quarter. 100% of our loan portfolio was funded with low-cost core deposits versus the aggregate of our peer banks at 88%. In the first quarter, total deposits increased by $188 million, while we maintained a very low cost of funds of 23 basis points, 36 basis points lower than our peer median.

American paid $11 million in dividends to HEI in the first quarter and remains well capitalized at March 31, with a leverage ratio of 8.6%, a tangible common equity to tangible asset ratio of 7.7% and total risk-based capital ratio of 14%.

On Slide 15, we are reaffirming HEI's 2018 earnings guidance in the range of $1.80 to $2 per share. There are no changes to the guidance ranges for the utility and the bank at this time.

I'll turn it over to Connie to make her closing remarks.

Constance Hee Lau
President, CEO & Director

Thanks, Greg. In summary, our companies continue to focus on our enterprise-wide mission of being a catalyst for a better Hawaii. At the utility, we are providing tax reforms, net benefits to customers and are on course to meet or exceed the state's 2020 target of 30% renewable energy. We look forward to participating alongside other stakeholders in the PUC's PBR docket as we work together to achieve our state's goals.

We are focused on our role in creating resilient, sustainable communities through technology, smart use of resources and building partnerships and providing more value to customers. At the bank, we look to build on its record earnings and profitability as we continue our work to make banking easier, deepen customer relationships, strengthen efficiency and enhance asset quality while growing the asset portfolio. And we very much look forward to the new campus opening later this year.

At Pacific Current, we are pleased to have 2 great projects in place and are prudently investing in the build-out of the organization.

Finally, our board yesterday maintained our quarterly dividend of $0.31 per share, continuing our history of uninterrupted dividend since 1901. The dividend yield continues to be attractive at 3.7% as of yesterday's market close. As always, our companies will continue to focus on providing long-term value for our customers, communities, employees and shareholders.
And now we look forward to hearing your questions.

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Question and Answer

Operator

[Operator Instructions] The first question comes from Julien Dumoulin-Smith of Bank of America Merrill Lynch.

Kim Zeng
BofA Merrill Lynch, Research Division

This is [Claire] for Julian. I wanted to first talk about Pacific Current. So I was hoping you could give a little more color beyond what you've provided so far, particularly earnings contribution, earnings cadence. And second, to follow up, if you can give a little more color on the strategic view for Pacific Current and the competitive dynamics for solar plus storage in the state.

Constance Hee Lau
President, CEO & Director

Sure. Thanks for your question, Claire. Frankly, Pacific Current is in a nascent stage right now, and as we indicated, we're really building that out. So we may have more of those specifics for you later in the year, but frankly, at this time, we're not in a position to provide those to you. However, we see that there are great opportunities within the state for us to help advance clean energy, and that's frankly why we started the Pacific Current strategy, is that when you have a state that has a very aggressive goal of 100% clean energy, and now we're also starting to work on the transportation side, we actually see that there's lots of opportunities to do things that frankly haven't been done in other places. And that's the reason why we needed another vehicle besides the utility and the bank to try to fill those gaps in our community. We actually have a number of folks in Hawaii that are very excited about clean energy and coming up with lots of different innovative proposals, and new companies, some of which you've seen transfer into the California market, like a Stem that has been involved in storage. And so we think that having this additional vehicle can allow us to support some of those efforts and work together in ways in Hawaii that you may never have seen elsewhere as we collaborate with everyone to do some pretty innovative things in energy. So stay tuned later this year.

Kim Zeng
BofA Merrill Lynch, Research Division

Great. That's really helpful. And just to quickly follow up, if there's any more color you can provide on the University of Hawaii project?

Constance Hee Lau
President, CEO & Director

Sure. I'm going to turn that over to Greg, who was involved in negotiating that transaction with UH and also our partner there, Johnson Controls.

Gregory C. Hazelton
Executive VP & CFO

Yes, Claire, so I can provide a little bit of additional color. We are -- the project now has been -- is in a notice to proceed stage, develop -- the final development, permits, transmission, interconnects and processes underway. JCI, who was the developer and also our EPC contractor, is proceeding with its work plan, which should deliver the project by mid-2019. I would caution that there are actually 5 different campuses, and frankly, each campus kind of has its own timeline. They're moving forward as quickly as they can on those, but we expect the vast majority of them to be online or COD by 2019, plus or minus a few months. We -- as I've mentioned previously, the contract with JCI is on a fixed price and strong performance guarantees backed by JCI, so we are funding -- currently funding the project and the construction phase, but we're not taking a construction risk. So you'll see us continue to fund that throughout the period of time until it reaches COD and is recapitalized at that point in time. Beyond

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that, things are progressing according to plan with good coordination among all the parties between us, University of Hawaii and JCI.

Constance Hee Lau
President, CEO & Director

Yes, so Claire, just to add, so we have typical construction financing in place through the banking market, but not American Savings Bank. As Rich would say, geez, how come? But through another banking consortium here in Hawaii. And then on COD, there will be nonrecourse financing that takes that out, typical project financing. But here is an example of what I was talking about. Because in Hawaii, it's not only the power sector that has great desires to go green and renewable. The University of Hawaii itself has a goal to be net 0 by 2035. And so this is part of their plan that they've actually been working on for quite a while to get their campuses to that net 0 stage. And we're very happy to be able to partner and be a catalyst, which is our mission for Hawaii, to be a catalyst to help get the University of Hawaii to their mandated 2035 net 0 goal.

Kim Zeng
BofA Merrill Lynch, Research Division

Excellent. That's really helpful color. And lastly, just a -- I know you've already given great detail on the PBR docket. If you can give a little more detail on what exactly needs to be in place by 2020 or at least what you can provide at this time.

Alan M. Oshima
President, CEO & Director of Hawaiian Electric Company Inc.

Let me just -- this is Alan. We have Joe Viola here, our VP of Regulatory, if we need more detail. But in general, it's broken down into 2 phases, and by the end of 2020, we expect to have a PUC road map for PBR. PUC opened the docket -- has been working on it for quite a while. We've been advocating for PBR for decades. So I think what we have is a rational docket with all stakeholders that will be around the table, going through a very complex regulatory mechanism. And by the end of the 2-year period, we should have a road map that is rational and, we hope, continues to live by preserving the financial integrity of the utility, and PUC has mentioned in its order opening the docket.

Operator

The next question comes from Paul Patterson with Glenrock Associates.

Paul Patterson
Glenrock Associates LLC

Just if we can get a little bit more clarity on SB 2939 and how it relates to the PBR docket? I mean, how are they different, I guess? Or how should we think of SB 2939 in the context of the docket at the PUC currently and outside of it?

Alan M. Oshima
President, CEO & Director of Hawaiian Electric Company Inc.

Well, I think you can think of it as the PUC's order actually predated the signing of 2939, and in the order, it covered most of the relevant, substantive matters discussed in 2939 and it even adopted a schedule that seemed to comply with the intent of 2939. But the PUC was very careful in its media release and in the order to say that this is not a wholesale change to the regulatory environment. We already have performance incentive mechanisms, but PUC is moving in that direction. We have filed testimony in our rate cases on PBR. We have suggested certain kinds of actions. And I think the PUC was very careful to say that Hawaii is unique, and there will not be a wholesale adoption of other areas' PBR mechanisms to the very unique circumstances in Hawaii. I think they comply. And even in the docket itself, some of the parties who were advocating for 2939 have recognized that the PUC's process seems to comply with the intent of 2939.

Paul Patterson

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Glenrock Associates LLC

Okay. There were some reports that you guys weren't supportive of 2939. Were your concerns resolved during the legislative process? Or are there any concerns that you guys have now?

Alan M. Oshima
President, CEO & Director of Hawaiian Electric Company Inc.

Our concerns are the unintended consequences and a rush to judgment. We have strongly advocated for the notion of PBR. We want a rational process with all stakeholders around the table, not just some. And I think the IPP community, for example, has already filed letters with the Governor, saying that the unintended consequence, if you destroy or greatly impact the utility's financial integrity is their ability to access reasonable financing as we move forward with our 100% RPS. We have a 300-megawatt RFP out there right now, and people have indicated interest in it. They have to access financing based upon our ability to pay as their customer. So these are some of the unintended consequences if PBR is not done rationally, and they've registered their concerns about it. But I think the PUC understands that.

Paul Patterson
Glenrock Associates LLC

Okay. Let me tell you where it's a little confusing to me, and that is, first of all, as you mentioned, this PUC order came out just before it seemed the Governor signing the bill or within days before. And I don't know if that was a coincidence or not. And I guess what I'm sort of wondering is -- I mean, I understand that you think that the PUC is complying with 2939, but I guess what I'm wondering is if the PUC was doing this, et cetera, why was 2939 necessary? And what drove that? Could you help us out a little bit on that?

Alan M. Oshima
President, CEO & Director of Hawaiian Electric Company Inc.

I won't speculate as to why it's necessary. We have made our positions clear. I will say that the PUC order was not done in a week. It's been in the process for months. And while the bill was being processed, the PUC had continued its quarterly deliberations to issue an order. So the timing may be coincidence or the timing may be as a result of the bill arriving on the Governor's desk, I cannot say. We are pleased that the PUC took the action it took.

Constance Hee Lau
President, CEO & Director

Paul, I think what you have to understand about Hawaii is that it's kind of like what I was saying about the University of Hawaii, is that across our communities, it is no longer just about the utility and just about moving clean energy forward through the utility process. As you know, with distributed energy resources, there are so many parties that need to come together to work through regulatory frameworks, rational frameworks that can actually best advance the state's goals to get to the ultimate goal line. And another example of that is on the transportation side, we have our 4 county mayors who have said that they want all ground transportation to be nonfossil as well. So like I say, we've got our whole community moving, and our position is that frankly, the Public Utilities Commission process, similar to what we went through in doing the grid modernization strategy when we -- where we were able to bring in and the PUC was able to bring in all relevant parties in our community to work through something that would work best for everyone and for the state, that's the nature of this PBR docket. But there are -- the good thing is there's a lot of people in our community who want to see that happen sooner, rather than later. And that's what you see in the intent of 2939 is that desire within the community to move all of these things forward as quickly as possible.

Alan M. Oshima
President, CEO & Director of Hawaiian Electric Company Inc.

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But I will put a side note on that. 2939 does a lot -- require the PUC to implement it. It's not the legislature that's going to implement this. They set the policy, but PUC will implement. As I mentioned earlier, the PUC had already been working on this for months. It was not as a result of 2939.

Paul Patterson
Glenrock Associates LLC

No, I'm aware of that. I guess what surprises me, I guess, is that there's this PUC process underway. I assume that the legislature was informed of that, and yet they moved ahead with their own legislation, which my understanding was you guys weren't supportive of. So I guess what I'm wondering -- I mean, I guess, and I don't want to belabor this topic. So I mean, I guess what my question sort of is, is what is it that 2939 does that the PUC wasn't doing or that -- I guess, what was the purpose of 2939 policy-wise? If there's a short answer to that, I don't mean to -- do you follow what I'm saying? It's a little confusing that you had this process underway that you guys think is basically compliant with...

Alan M. Oshima
President, CEO & Director of Hawaiian Electric Company Inc.

Thank you, Paul. We understand your question. We have the same question, frankly, and we advocated to allow the PUC to do its job in our testimony as is the consumer advocate. So why it was passed and why the Governor moved to it is really speculation on our part. It's there, but we are very, very comfortable that the PUC will implement it in a rational way.

Paul Patterson
Glenrock Associates LLC

Awesome. Okay. And then, I'm going to now ask a bank question. The debit card interest -- the interchange fee and the change in accounting, could you just elaborate a little bit? I apologize if I forgot what that is, [and generally] where that now shows up or how that's -- if you could just elaborate a little more on that.

Richard F. Wacker
President, CEO & Director of American Savings Bank FSB

Yes. This is Rich. Thanks for the question, Paul. So there's 2 pieces in the income statement that come from our customers using their debit card. One is in the noninterest income. When they swipe, we get a fee on the transactions governed by the caps on Durbin, as we've talked to you in the past. And that comes through, and there's the volume-related component. The more swipes, the more income we get. Within other expense, we've had the charges that come with it, right? So there is a similar -- under the card agreement and the association agreements, there's a similar charge that comes through. And so they've just been in 2 pieces. What this does is it brings them together so that within noninterest income, you see the net of debit card income, net of the expenses associated with those swipes.

Paul Patterson
Glenrock Associates LLC

Okay. And what's changed?

Richard F. Wacker
President, CEO & Director of American Savings Bank FSB

Geography. So no bottom line impact. It's bringing them that expense up from the noninterest expense line and other expense to noninterest income, where you're offsetting some of the debit card interchange income.

Operator

The next question comes from Rose-Lynn Armstrong with UBS.

Rose-Lynn Perry Armstrong
UBS Investment Bank, Research Division

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Just 2 more process-related questions on the PBR docket and the legislation. Did I hear you correctly that the PBR docket, the 2 phases would be completed by the end of 2020?

Alan M. Oshima
President, CEO & Director of Hawaiian Electric Company Inc.

Roughly, yes. And it's left up to some allowance for some slippage or advancement. The docket has just been opened. Intervenors have filed for intervention. There's going to be a convening of all the parties, we think, in a few months or so. So we'll know more once that's done.

Rose-Lynn Perry Armstrong
UBS Investment Bank, Research Division

Okay. So then how does that work in with the timeline for the legislation, which I believe calls for implementation by January 1, 2020? And then secondly, who will decide if the PUC outcome on PBR implementation complies with the intent of the legislation?

Joe Viola
Vice President of Regulatory

This is Joe Viola from Hawaiian Electric Regulatory. Actually, the PUC schedule.

Constance Hee Lau
President, CEO & Director

Can you all hear Joe?

Rose-Lynn Perry Armstrong
UBS Investment Bank, Research Division

Yes.

Constance Hee Lau
President, CEO & Director

Okay. All right.

Joe Viola
Vice President of Regulatory

As for the PUC schedule, it largely complies with the statute. It's not at the end of 2020. The PUC schedule actually completes these 2 basically in the first months of 2020. The bill called for implementation of PBR by January of 2020, so it's pretty much aligned right there. As far as who will judge it, I mean, we can't speculate on that, but again, as Alan said earlier, we think the process that the commission set out satisfies the intent of the statute.

Operator

The next question comes from Jonathan Reeder with Wells Fargo.

Jonathan Garrett Reeder
Wells Fargo Securities, LLC, Research Division

Just to follow up again on the legislation. I think part of the language [said] it is to break the direct link between the allowed revenues and investment levels, so CapEx, rate base. Like how do you envision, I guess, complying with that aspect of it without, I guess, kind of turning the current rate base models on its head?

Alan M. Oshima
President, CEO & Director of Hawaiian Electric Company Inc.

We don't -- the statute says that. The PUC order does not say that. The PUC was charged with implementing. The newspapers, within days of the signing, called for amendments to the law. We don't

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know if that's going to happen to give the PUC more flexibility in this very complex area and to avoid unintended consequences. The road has been -- I mean, the goal has been set. The PUC has been working on it for a while. We'll see how this develops. There are changes that may come about as people understand the complexities of moving to PBR.

Constance Hee Lau
President, CEO & Director

And Jonathan, I'd add that if you look at the PUC order, an example of what you're talking about is that they specifically say that they want to make it neutral between capital expenditures and also services that are provided because that is what's happening in the energy landscape is you're starting to see lots of other products and services that customers want. And if you look at the recent incentive that was provided to us on renewable procurement, there's an example of potential revenues and incentives that can come from us not making a capital investment but instead procuring competitively priced purchase power, right? So there's where we could potentially have a 20% of the savings against to target benchmarks of procurement.

Alan M. Oshima
President, CEO & Director of Hawaiian Electric Company Inc.

Which we already do, but we don't have the incentive built into the regulation.

Constance Hee Lau
President, CEO & Director

Right.

Jonathan Garrett Reeder
Wells Fargo Securities, LLC, Research Division

Right. So I mean, I guess, in your view that, I guess, sharing of the savings breaks the direct link between kind of revenues and investment levels? I mean, even if it's in, say, the utility favor, so to speak, but you still have the underlying kind of rate base model, and then you layer on perhaps that kind of service component as well as checking the boxes, plus or minus on certain performance metric achievements, and you kind of get to this new framework that's being contemplated?

Constance Hee Lau
President, CEO & Director

Yes, exactly.

Alan M. Oshima
President, CEO & Director of Hawaiian Electric Company Inc.

You said it well. You want to testify in the docket?

Jonathan Garrett Reeder
Wells Fargo Securities, LLC, Research Division

No, I don't think I'd do that. I think I'll pass. But maybe I'll come out and visit and listen to some of the hearings and enjoy the beach.

Constance Hee Lau
President, CEO & Director

Yes, you may want to do that because, frankly, Hawaii is leading the nation in lots of these new frameworks that will lead us to clean -- 100% clean energy.

Operator

The next question comes from Charles Fishman with Morningstar Research.

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Charles J. Fishman
Morningstar Inc., Research Division

I think my question is going to be directed to Greg. Greg, is there anything in the electrification of transportation road map? Is there anything in 2939? Is there anything in the ongoing commission docket with respect to PBR that gets you more excited about the opportunities for Pacific Current? Or does any of those things make it harder for Pacific Current? If you could comment on that.

Gregory C. Hazelton
Executive VP & CFO

Yes. Thanks, Charles. No, I think Connie said it well in that Pacific Current was created to help move the state forward on its renewable energy goals. A lot of the investment that will get us there is going to be made in the competitive market, not just purely through the utility. And consequently, being a local player, our ability to partner with local developers, local teams that are pursuing renewable energy, we create a good platform for capital formation in partnering with those parties. Tax reform was clearly a benefit to Pacific Current if you think about after-tax cash flows from a nonregulated enterprise. So I see that as a benefit. But I'm not concerned about any of the regulatory dynamics overall at the utility. Those will progress on pace. We'll be focused on other activities and other opportunities working locally with other partners.

Charles J. Fishman
Morningstar Inc., Research Division

Like on the UH project, you are the equity behind that, not the university, not Johnson Controls?

Gregory C. Hazelton
Executive VP & CFO

Yes, we're the ones that funded -- that are funding that project, and we're the ones that provided the lowest cost to the university relative to a large number of competitors that were looking at that same project. So our involvement resulted in a very -- a lower cost than otherwise would have been obtained by the university. And so we're proud of our involvement there, and we're proud to have brought together a local team to accomplish that.

Charles J. Fishman
Morningstar Inc., Research Division

So I mean, really what drives the Pacific Current opportunities are more of the RPS, the aggressive RPS goals of Hawaii rather than this PBR noise?

Constance Hee Lau
President, CEO & Director

Charles, it's not just the RPS but it's all the other things that I was talking about. All those policy moves like on the transportation side, for example, the net 0 for the University itself. So that's what I was trying to describe earlier. We've got our entire community here in Hawaii moving towards cleaning -- clean energy. And if you remember back to one of the principles of the Hawaii Clean Energy Initiative back in 2008, it's because our entire state is very dependent on imported fossil fuel. So we're an island. We don't -- back then with the technologies, you might have indigenous resources like the sun and the wind, but the technology is really not in the money, so to speak. So oil was the least expensive way to generate power here, and also to provide gasoline for the cars and the jet fuel for the airplane. That made Hawaii really dependent on oil. And then when you had the oil price shock flare in April of 2008, you started seeing oil prices climb, and then, boy, when you had Fukushima occur, that just jacked up all of the oil prices in the whole Asia Pacific region. The Hawaii economy really took a hit from the standpoint of that oil expense going through the roof, and that was just not power generation. That was across the board.

Operator

The next question comes from Jackie Bohlen with KBW.

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Jacquelynne Chimera Bohlen
Keefe, Bruyette, & Woods, Inc., Research Division

I'll switch it over. I'm giving Rich a little bit of air time here, for my usual. I guess focusing first on the net interest margin. I know it's within the range that you had spoken about it. It certainly came in above my expectations. Just if you could talk about how you're thinking about asset repricing and deposit repricing in light of March's increase and then if we were to get any additional increases later this year.

Richard F. Wacker
President, CEO & Director of American Savings Bank FSB

Yes, we're expecting one more increase this year. That's kind of our plan. And as we -- I think you've observed, we're fighting pretty hard to control the cost on the funding side, and we've been able to do that pretty well. A lot of it is through the approaches that we're taking, particularly in the retail network on our relationship banking. So we want to keep pushing that. We are seeing pressure in the market, particularly on the commercial side, where the pricing is getting more competitive. And so we were up a couple of basis points in the quarter. We're trying to keep it at that level and control the upward pressure there. On the asset side, again, commercial pricing is competitive as is residential because there's just no movement on the volume in the market on residential, with refis flat and limited inventory on that side. So those are going to remain fairly competitive. But in the investment portfolio, we're getting nice movement on the yields there as we reprice.

Jacquelynne Chimera Bohlen
Keefe, Bruyette, & Woods, Inc., Research Division

And do you know -- do you happen to know what the reinvestment differential is on where the portfolio stands versus what you're purchasing?

Richard F. Wacker
President, CEO & Director of American Savings Bank FSB

It's -- right now, we're plus 80 basis points.

Jacquelynne Chimera Bohlen
Keefe, Bruyette, & Woods, Inc., Research Division

Okay. And that was as of 1Q? Or is that current?

Richard F. Wacker
President, CEO & Director of American Savings Bank FSB

Yes, that's as of 1Q.

Jacquelynne Chimera Bohlen
Keefe, Bruyette, & Woods, Inc., Research Division

Okay. And then if you wouldn't mind providing an update on where you stand in terms of intended portfolio runoff and how much more you expect to come this year and kind of where you're seeing most of your growth in terms of new generation.

Richard F. Wacker
President, CEO & Director of American Savings Bank FSB

So the new generation has been pretty good. Last year was challenging for us on the commercial side as we were repositioning that book on some of the leverage lending and national credit. And we got through that in the fourth quarter, so you saw us get the growth started up again as we came into the first quarter. We were -- loan growth was at about 6, and we want to keep playing in that mid-single-digit range on loan growth. And then obviously, the investment portfolio will depend on deposit growth.

Jacquelynne Chimera Bohlen
Keefe, Bruyette, & Woods, Inc., Research Division

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Okay, fair enough. And then just one last one. If you could provide an update on your expectations for the timing and perhaps the amount on any costs you're going to have associated with the capitalization of the new campus.

Richard F. Wacker
President, CEO & Director of American Savings Bank FSB

So the campus, we would expect to be completed with the investment on that this year. We're hoping to get the building in the early fourth quarter to fit it out with furniture and everything and then be able to start moving in towards the end of the year and the first part of next year. So we're excited about that. As Connie mentioned that earlier on, we're moving from 5 different locations for people who are in the branches to one, and we think that helps us a lot on a go-forward basis in terms of how efficiently and nimbly we can operate. So we're looking forward to that. We'll probably have on the order of $1 million of costs -- sort of project-related costs associated with moving in and beginning to exit those other properties. That will come through this year and you'll see that in the noninterest income line. And about -- that will come -- noninterest expense line, sorry.

Jacquelynne Chimera Bohlen
Keefe, Bruyette, & Woods, Inc., Research Division

And what about any future capitalized cost that might be depreciating, when would that start?

Richard F. Wacker
President, CEO & Director of American Savings Bank FSB

Depreciation would probably start either December fourth quarter or first quarter next year, depending on the completion of the construction.

Jacquelynne Chimera Bohlen
Keefe, Bruyette, & Woods, Inc., Research Division

Okay. And I would guess there will likely be some offsetting benefits just from consolidating from other areas?

Richard F. Wacker
President, CEO & Director of American Savings Bank FSB

Yes, and we've got a couple of the properties that we're in that we own that we would expect to see sales at positive -- with positive effect on the income statement. We should see gains on the properties that we sell. Timing, hard to call.

Operator

This concludes the question-and-answer session. I would like to turn the conference back over to Julie Smolinski for any closing remarks.

Julie Smolinski
investor relations contact

Thank you, Gary. Thank you, everyone, for participating in today's call. Have a good rest of the week.

Operator
The conference has now concluded. Thank you for attending today's presentation. You may now disconnect.

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OGE Energy Corp. NYSE:OGE

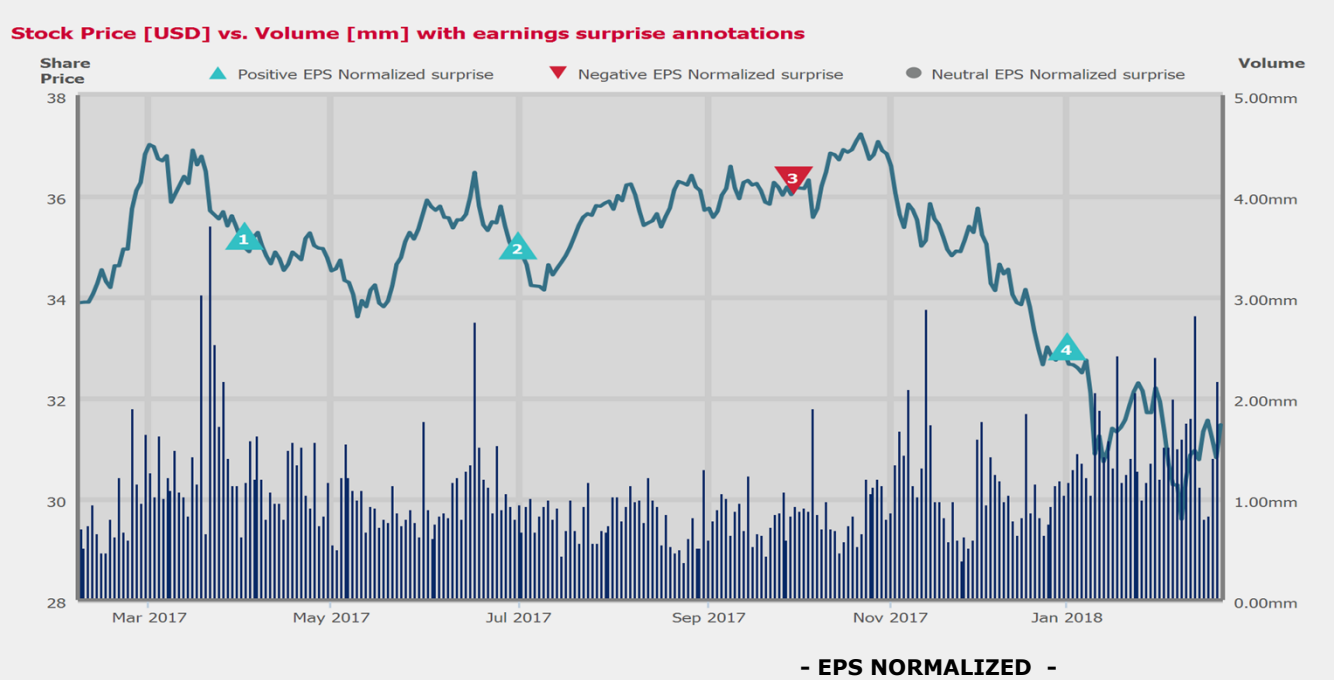
FQ1 2018 Earnings Call Transcripts

Thursday, May 03, 2018 1:00 PM GMT

S&P Capital IQ Estimates

	-FQ1 2018-			-FQ2 2018-	-FY 2018-	-FY 2019-
	CONSENSUS	ACTUAL	SURPRISE	CONSENSUS	CONSENSUS	CONSENSUS
EPS Normalized	0.16	0.27	68.75	0.50	2.00	2.10
Revenue	-	-	4.68	-	-	-
Revenue (mm)	470.69	492.70	-	604.16	2316.17	2452.11

Currency: USD
Consensus as of May-02-2018 4:30 PM GMT



- EPS NORMALIZED -

	CONSENSUS	ACTUAL	SURPRISE
FQ1 2017	0.16	0.18	12.50 %
FQ2 2017	0.47	0.52	10.64 %
FQ3 2017	0.94	0.92	(2.13 %)
FQ4 2017	0.28	0.30	7.14 %

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Presentation

Operator

Good day, ladies and gentlemen, and welcome to the OGE Energy's First Quarter 2018 Earnings Conference Call. [Operator Instructions] As a reminder, this conference call is being recorded.

I would now like to introduce your host for today's conference, Todd Tidwell, please go ahead.

Todd Tidwell
Director of Investor Relations

Thank you, Abigail. Good morning, everyone, and welcome to OGE Energy Corp's First Quarter 2018 Earnings Call. I'm Todd Tidwell, Director of Investor Relations. And with me today I have Sean Trauschke, Chairman, President and CEO of OGE Energy Corp.; and Steve Merrill, CFO of OGE Energy Corp.

In terms of the call today, we will first hear from Sean, followed by an explanation from Steve of first quarter results and finally, as always, we will answer your questions. I would like to remind you that this conference is being webcast and you may follow along on our website at oge.com. In addition, the conference call and accompanying slides will be archived following the call on that same website.

Before we begin the presentation, I would like to direct your attention to the safe harbor statement regarding forward-looking statements. This is an SEC requirement for financial statements and simply states that we cannot guarantee forward-looking financial results, but this is our best estimate to date.

I would also like to remind you that there is a Regulation G reconciliation for gross margin in the Appendix.

I will now turn the call over to Sean for his opening comments. Sean?

Robert Sean Trauschke
Chairman, President & CEO

Thank you, Todd, and good morning, everyone, and thank you for joining us on today's call. Well, it is May in Oklahoma and that usually means storms and extreme weather. And yesterday and through the night our service territory expands tornadoes and rain, hail, high winds just the full complement. But our crews did a great job, as usual, working through the night and I'm happy to report all customers will be back in service this morning.

So turning to the quarter. Earlier this morning, we reported first quarter consolidated earnings of $0.27 per share. And both businesses performed well and accomplished a great deal. So we're off to a great start and certainly on plan for the year.

At the utility, revenues benefited from positive whether and the impact of rate design from last year's Oklahoma rate award. Steve will discuss the details in a moment. But right now, I want to highlight our first quarter achievements. Our new state-of-the-art Mustang Energy Center is in operation serving our customers. We're proud to usher in a new era of generation technology at a location that's been powering our communities and facilitating a critical role in the region's growth and economic development. The Mustang Energy Center is more efficient, more sustainable and more responsive, and it maintains its legacy of providing affordable and reliable power to our communities. The new units with their staggered market availability dates have already seen close to 500 starts and produced more megawatts through the first four months of this year than the legacy units did all of last year. From an emission standpoint with the new units, we are experiencing a 62% decrease in our NOx emission rates. This further validates their importance in the SPP footprint. This was a project of substantial scale that required numerous contractors, hundreds of workers and more than 1.4 million work hours. As testament to the hard work and commitment, the project was executed on time, under budget and incident and injury free. It doesn't get any better than this.

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Our service territory continues to grow with 7,200 new customers over the last year. And we are growing near our historical average of 1%. I should note, quarter-over-quarter, we experienced a 4% increase in oilfield sales and a 5% increase in industrial sales. The latest economic statistics put Oklahoma's unemployment rate at 4.1%, which is on par with the national average. Our largest load center, Oklahoma City, is below the national average, all signifying an improving economic outlook.

On the operations front, the start of 2018 has continued our success. Our combined cycle and call units have had their best availability to the market this quarter since we entered the SPP integrated market in 2014. This is important because it demonstrates that we've been flexible, reliable and adaptable to both market and commodity changes, and how our units are utilized in the market. [Safety] for the quarter saw 20% improvement over the first quarter of 2017. Our Covington solar farm is in service. The Sooner Scrubbers project is 82% complete, on time and on budget. And we're currently setting record performance in safety results, going 209 days without an incident, excellent performance.

I have to be honest, it feels good to have the first quarter behind us with a positive benefit from weather. Albeit small, it's the first time in a number of years that we have begun the year with positive weather. Further to that point, it had been 5 years since we've had benefit from favorable weather. I say that only to make the point that weather changes and it is not something you control. What does not change is our execution and focus on getting better. Another quarter of solid execution by everyone here at the company.

This year, we will restart our focus on grid modernization. We plan to begin significant deployment in Arkansas with Oklahoma following in 2019. Grid modernization is the next step in our smart grid deployment, this initiative will focus on improving, replacing existing distribution infrastructure, as well as upgrading systems that allow us to respond to outages more quickly and seamlessly connect with new energy technologies in the future. We'll be able to improve the reliability and resiliency of our grid as well as reduce cost for our customers and more efficient response in operation. As we move forward, we will optimize ideas and applications across our service territory that improve reliability and provide the most benefit to our system and to our customers. This will enable us to meet customer demands and to position our infrastructure for the future.

Turning to regulatory. As you know, we filed a general rate review with the Oklahoma Commission in January. The primary purpose of that filing is recovery of the Mustang Energy Center. And we'll make her first Arkansas Formula Rate filing in October. We will then file another case in Oklahoma at the end of 2018 for the recovery of the Sooner Scrubbers. We anticipate the first scrubber to be in service in June, and in fact, the work to tie in that first scrubber is currently underway. Finally, last week a ruling was issued against the OCC, finding they did not have the authority to grant preapproval of our scrubbers at Sooner under the statue used. This does not change the intent or the unanimous approval of the commission to the reasonableness of our plan, and we'll work with the commission to resolve this in our filing later this year.

Moving on to Enable. On their call yesterday, they reported strong results for the first quarter. They reported all-time high quarterly natural gas gathered volumes and processed volumes, supported by strong rig activity in the Ark-La-Tex and Anadarko basins. As you know, volumes are the key to this business. Quarter-over-quarter, natural gas gathered volumes increased 30% and processed volumes increased nearly 19%. Year-to-date, they have contracted or re-contracted multiple transportation agreements with over 375,000 dekatherms a day of capacity. They've also updated their outlook to reflect an even stronger 2018. So as a sponsor of Enable, we continue to be pleased with their performance and what the Enable team is building. Last, but not least, the Enable Board approved a quarterly distribution this week of $35 -- of which $35 million will be distributed to OGE. This will make distributions received by OGE since the formation of Enable totaling more than $800 million. This unencumbered cash has kept us out of the equity markets and supported our CapEx and dividend growth.

In closing, I want to reiterate how pleased I am with the performance of both businesses. We have a long-term utility growth rate of 4% to 6% and continue to grow our dividend at an industry-leading rate of 10% a year through 2019. As a management team, we're committed to executing on our strategy to continue

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growing our business, growing our communities and creating long-term shareholder value for all of our shareholders.

Thank you, and I'll now turn the call over to Steve to review our financial results for the quarter. Steve?

Stephen E. Merrill
Chief Financial Officer

Thank you, Sean, and good morning. For the first quarter, we reported net income of $55 million or $0.27 per share as compared to net income of $36 million or $0.18 per share in 2017. The contribution by business unit on a comparative basis is listed on the slide. At OG&E, net income for the quarter was $31 million or $0.16 per share as compared to net income of $16 million or $0.08 per share in 2017. First quarter gross margin at the utility increased approximately $35 million, which I will discuss on the next slide. Looking at other key drivers, first quarter O&M expense decreased $5 million, primarily due to the timing of plant maintenance. O&M expense for the year is on plan. Depreciation increased $24 million. The primary driver for the variance is timing related to last March's Oklahoma rate order.

As you will recall, we booked 6 months of 2016's depreciation adjustment, approximately $20 million, in the first quarter of 2017. Interest expense increased approximately $4 million due to the additional long-term debt issued in March and August of 2017. Income tax expense decreased $4 million due to the reduction of the corporate federal tax rate and an increase in state tax credits generated, partially offset by higher pretax income.

Turning to the first quarter gross margin. Utility margins increased approximately $35 million in the first quarter of 2018 compared to 2017. There are 2 main drivers for the increase. First is the impact of the Oklahoma rate order. You'll recall that we implemented new rates in May of 2017, therefore, margins in the first quarter of 2017 were under the old rates. Under the new rate design methodology, more revenue was shifted into the first quarter. Another way to say this is the small smoothing of our annual revenue curve. This change accounted for $19 million of margin or $0.07 per share.

The other main driver was weather. 80 degree days were 36% above last year and this accounted for $14.6 million of margin or $0.05 per share as well. There have been impacts from the 2017 rate order for the comparative periods, but the bottom line is that we anticipated this and we're on plan for the year.

Turning to our investment in Enable. For the first quarter of 2018, Enable made cash distributions of approximately $35 million, the same amount received in the first quarter of 2017. Enable also contributed earnings of $24 million or $0.11 per share, compared to $20 million or $0.10 per share in 2017. Enable had a solid first quarter and their financial metrics are strong. Enable set all-time quarterly records for gathering and processing volumes. Adjusted EBITDA increased by $36 million and DCF increased $25 million compared to the first quarter of 2017. They ended the quarter with a distribution coverage ratio of 1.4x. Enable increased their guidance for the year, which points to continued execution of the business in recovery and commodities. Enable remains focused on controlling costs and deploying capital effectively.

Turning to 2018 outlook. As you know, the majority of utility earnings occur in the second and third quarters and assuming normal weather, we're comfortable with our current guidance. In the Appendix, we have updated the guidance assumptions for this year following the revenue recognition and pension accounting changes. These are income statement reclassifications and do not affect our initial guidance ranges.
This concludes our prepared remarks, and we'll now answer your questions.

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Question and Answer

Operator

[Operator Instructions] Our first question comes from the line of Josephine Moore with Bank of America Merrill Lynch.

Josephine Moore
BofA Merrill Lynch, Research Division

I just -- you mentioned strong sales growth on the industrial side. I was just curious, is that temporary? Or could we see that continue?

Robert Sean Trauschke
Chairman, President & CEO

I think this is a good inflection point for an improving economic outlook here in our service territory. We saw an increase in oilfield sales, Todd and Steve both mentioned about the rig count at Enable. They have a lot of pipeline assets in our service territory. And we have mentioned for a number of quarters the -- some of the new businesses have been relocating to our service territory. Just last Friday, we commissioned and had the groundbreaking for a new steel company that relocated who is manufacturing rebar in the southern part of our service territory. So we're hopeful that there'll be more to come. But I think this is a very good inflection point for an improving economy.

Josephine Moore
BofA Merrill Lynch, Research Division

Great. I mean with that, the strong weather in the first quarter and then Enable's strong guidance for the last quarter, do you feel comfortable coming in maybe towards the high-end of the guidance?

Robert Sean Trauschke
Chairman, President & CEO

Yes, as Steve mentioned, the majority of our earnings, specifically at the utility, come in the second and third quarter. And while the weather benefit was favorable in the first quarter, it was still pretty small. And -- where the weather benefit will really occur to the extent that it is favorable will be in the second and third quarter. So we'll get through those quarters before we make any pronouncements about guidance. But we feel very confident that we're on plan.

Josephine Moore
BofA Merrill Lynch, Research Division

And then just 1 last question. On the rate case underway in Oklahoma, any updates you can give us there?

Robert Sean Trauschke
Chairman, President & CEO

Really no updates at this point. The intervenor testimony was due last night, so we will certainly go through that and evaluate that and proceed accordingly.

Operator

Our next question comes from the line of Paul Ridzon with KeyBanc.

Paul Thomas Ridzon
KeyBanc Capital Markets Inc., Research Division

What was the impact of -- I think last year you were booking interim rates for '16, what was the impact of that rolling off?

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Stephen E. Merrill
Chief Financial Officer

In the first quarter, we booked about $0.06 related to 2016 and 2017. So that all kind of pretty much flushed through the first quarter.

Paul Thomas Ridzon
KeyBanc Capital Markets Inc., Research Division

And it looks as though one of the things you called out was lower taxes -- but are you reserved against that? Is that -- if I read the queue properly?

Stephen E. Merrill
Chief Financial Officer

Well, we certainly have to refund currently because we're in the middle of a rate case, we're over-collecting from where tax rates are now. So we're reserving that over-collection to begin to give that back once we get an order from the commission. We don't have a mechanism to do that until they give an order to do so.

Paul Thomas Ridzon
KeyBanc Capital Markets Inc., Research Division

But you did not benefit from lower taxes in the quarter because you reserved against it?

Stephen E. Merrill
Chief Financial Officer

That's correct. That's correct.

Robert Sean Trauschke
Chairman, President & CEO

There's no P&L impact for us.

Operator

Our next question comes from the line of Shar Pourreza with Guggenheim Partners.

Shahriar Pourreza
Guggenheim Securities, LLC, Research Division

Can you hear me?

Stephen E. Merrill
Chief Financial Officer

Yes.

Shahriar Pourreza
Guggenheim Securities, LLC, Research Division

Sorry about that, it's -- this was [addressed], there're a couple of calls going on this morning. Just on sort of your grid mod filings. Can you just remind us -- it's a big piece of, sort of, your CapEx when you think about '19 and beyond. What sort of the podium as far as how you're thinking about recovery? Is it within the FRP that's, sort of, happening in Arkansas? Would it necessitate another filing in Oklahoma. And sort of, I guess, more importantly, how's the educational process going on, especially on grid mod in Oklahoma?

Robert Sean Trauschke
Chairman, President & CEO

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So a really good question. And I think you kind of laid out our game plan. In Arkansas, we will use the FRP. We'll be making those filings on an annual basis and so that's how we'll recover that. And we'll begin as we restart this program. Remember, we, kind of, delayed it as we were going through this environmental compliance plan because of the federal requirement. But -- and we'll begin this in Arkansas, we'll pick this up after the Mustang and Sooner projects are complete in Oklahoma. And you're exactly right, we will probably have a lot of dialogue and discussion with the Oklahoma commissioners and staff to make sure that they recognize the full benefits of that. And then see if we can't develop a constructive pathway to see that recovery, whether that includes a rider, whether that includes formal rate-making process, we'll cross that bridge when we get there. But I think your point is exactly right. It's our job to make sure that we educate them beforehand.

Shahriar Pourreza
Guggenheim Securities, LLC, Research Division

Got it, that's helpful. And then just on Oklahoma's, sort of, construct, right. Is there any sort of updates on how the focus groups and everything is going as far as looking in and potentially revisiting how the Oklahoma or the OCC sort of accounts for their regulatory proceedings? Is there any status there? And then just looking at the rate case that we have with interim rates that are -- should be, I guess, implemented sometime in the middle of this year. What is sort of your viewpoint as far as a potential settlement?

Robert Sean Trauschke
Chairman, President & CEO

Sure. So good question. So as it relates to the task force that was initiated by the Governor last year, I know they're conducting interviews and I think the plan is they're going to release the interim report this summer and then, I think, their final report is due the 8th-or-so of November after the elections. And so we'll see where that comes out at. So I think that process is proceeding. As far as this case we have before us on Mustang, you're right, I guess you're referring to the 180-day timeframe that we could implement rates this summer, that's exactly right. I would be hopeful that we would not get to that point. As you recall, we delayed the filing of this Mustang case to incorporate the benefits of tax reform. There is going to be no impact for this investment to our residential or industrial customers. And so we think this is teed up very nicely to get resolved. And I'm hopeful that it can get done before we have to implement rates.

Shahriar Pourreza
Guggenheim Securities, LLC, Research Division

And that just leads me to just 1 last question. On the upcoming rate filing as far as the -- from the Scrubbers and the conversion, is there -- do you have any indication preliminary of what the impact could be from a retail rate perspective there?

Robert Sean Trauschke
Chairman, President & CEO

You're talking about on the Scrubbers?

Shahriar Pourreza
Guggenheim Securities, LLC, Research Division

Correct.

Robert Sean Trauschke
Chairman, President & CEO

So we're working through that right now. And it's probably a bit premature to, kind of, put that number out there too soon. But I do not view that as a large impact.

Operator

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And your next question comes from the line of Greg Gordon with Evercore ISI.

Unknown Analyst

This is actually [indiscernible] on for Greg. So my questions on the rate case you guys have already answered. Just on the dividend, so target is 10% through '19. Is that -- when does that get reviewed?

Stephen E. Merrill
Chief Financial Officer

I mean, we're already taking a look at that, but we certainly want to get through the Mustang filing, have some early indications on Sooner and then it would be something we would address sometime next year.

Unknown Analyst

Perfect. And then just on the -- so you guys increased your CapEx in the last call. Just wanted to get an understanding at a high level, where does that put you in terms of either CFO-to-debt metric? And what are you targeting? So I'm trying to get to how much excess balance sheet capacity you may have now that you've increased your CapEx?

Stephen E. Merrill
Chief Financial Officer

Sure. I think what you'd see with that CapEx is our FFO-to-debt staying in line with where we've been historically, strong investment rate. We would look to that not to have any impact on our credit metrics and that's kind of how we manage the company to -- keep a strong FFO to debt consistent with where we've been. Yes, obviously, north of 20%. Last year was kind of our highest CapEx, so that put a little stress on our FFO-to-debt, and we'll be working through that as we start to get recovery for these assets we've put in service.

Unknown Analyst

It goes north of 20%?

Stephen E. Merrill
Chief Financial Officer

Yes.

Unknown Analyst

And that's through your CapEx forecast period? Or through 2020?

Stephen E. Merrill
Chief Financial Officer

No, through the CapEx forecast period.

Operator

Our next question comes from the line of Joe Zhou with Avon Capital Advisers.

Andrew Levi
Caris & Company, Inc., Research Division

It's Andy Levi. Just two questions. Just on Enable and CenterPoint's bid -- not bid, but the acquisition of Vectren. Just any thoughts on how that may or may not affect Enable? And also your thinking on Enable?

Robert Sean Trauschke
Chairman, President & CEO

Well, it doesn't change our thinking on Enable. We are very comfortable with Enable, we like that business, we understand that business, so it doesn't change our thinking on Enable. I think in fairness, Andy, I do

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agree with you. It probably does bring back to the forefront the exposure to CenterPoint's process with regard to the Enable units. But as far as what actually happens there, you need to ask CenterPoint. That's their decision, and it's their responsibility to communicate that.

Andrew Levi
Caris & Company, Inc., Research Division

Okay. And then just on the current rate case, so you said last night intervenor testimony was filed, does that include staff as well or just intervenor?

Robert Sean Trauschke
Chairman, President & CEO

Yes, yes, so it was all -- as soon as it's made public, we'll go through it all and figure out what happens, what everyone said. But yes, that was the deadline was late yesterday afternoon and so I think they're loading it and putting it on the system right now.

Andrew Levi
Caris & Company, Inc., Research Division

Okay, and that again -- that includes the staff?

Robert Sean Trauschke
Chairman, President & CEO

Yes, yes, it does.

Andrew Levi
Caris & Company, Inc., Research Division

And so just to understand the process from here, I guess settlement conference takes place in the first week of June or something like that?

Robert Sean Trauschke
Chairman, President & CEO

That's correct. It's set for June 8. But Andy that's the procedural schedule, that doesn't -- we'll evaluate where everything comes in at and to the extent that there is an opportunity to have productive discussions, we will.

Andrew Levi
Caris & Company, Inc., Research Division

Before June 7, you're talking?

Robert Sean Trauschke
Chairman, President & CEO

Yes.

Andrew Levi
Caris & Company, Inc., Research Division

I understand, that makes sense. Okay, so basically now since the testimony has been filed and everyone knows each other's positions for no better way to put it, it's a good time if the parties want to, to sit down and talk, is that fair?

Robert Sean Trauschke
Chairman, President & CEO

Yes.

Andrew Levi

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Caris & Company, Inc., Research Division

Okay. And I guess we're fairly optimistic hopefully that you guys will settle something.

Robert Sean Trauschke
Chairman, President & CEO

No, no, I agree, keep going.

Operator

And we have a follow-up from the line of Paul Ridzon with KeyBanc.

Paul Thomas Ridzon
KeyBanc Capital Markets Inc., Research Division

Just wanted to go back to the interim rates. So does that imply that we really saw the $0.07 you mentioned plus the $0.06 of rate design shifting throughout the year?

Stephen E. Merrill
Chief Financial Officer

Well, the $0.06 was in the first quarter of 2017. You did see the impact of rate design in this current quarter.

Paul Thomas Ridzon
KeyBanc Capital Markets Inc., Research Division

I got it. This is a normal quarter and last year was [indiscernible].

Stephen E. Merrill
Chief Financial Officer

Yes, that's right, that's exactly right.

Paul Thomas Ridzon
KeyBanc Capital Markets Inc., Research Division

Okay, okay, got it. And how do you see that $0.07 kind of reversing out over the course of the year?

Stephen E. Merrill
Chief Financial Officer

I mean it really will be -- AFUDC will kind of play out through the year. But you really wouldn't need to adjust probably what you have for second, third and fourth quarters, this is just a slight shifting into the first quarter.

Paul Thomas Ridzon
KeyBanc Capital Markets Inc., Research Division

Okay, so a couple of pennies each quarter?

Stephen E. Merrill
Chief Financial Officer

That's probably not too far off, yes.

Operator

[Operator Instructions] We have a follow-up from the line of Josephine Moore with Bank of America Merrill Lynch.

Josephine Moore
BofA Merrill Lynch, Research Division

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Just one very quick follow-up on here. On a run rate basis, your O&M seems to come in pretty -- or your total OpEx comes in below guidance. Are we expecting a meaningful uptick there in the later quarters or...?

Stephen E. Merrill
Chief Financial Officer

Yes, it's really just a timing issue. We're actually on plan with what we put out for guidance, it's really just timing of expenditures, particularly plant maintenance. Your outages tend to occur in the summer months and in the fall.

Josephine Moore
BofA Merrill Lynch, Research Division

Got it. And then Sooner coming online too, is that also a driver there?

Stephen E. Merrill
Chief Financial Officer

Sure. Yes, absolutely.

Robert Sean Trauschke
Chairman, President & CEO

There will be some OpEx associated with that.

Operator

At this time, I'm showing no further questions. I would like to turn the call back to Sean Trauschke for closing remarks.

Robert Sean Trauschke
Chairman, President & CEO

Thank you, Abigail. And thank you all for your interest in OGE Energy Corp. and for being on the call today. Have a great day.

Operator
Ladies and gentlemen, thank you for your participation in today's conference. This concludes the program and you may now disconnect. Have a great day.

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S&P Capital IQ

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PNM Resources, Inc. NYSE:PNM

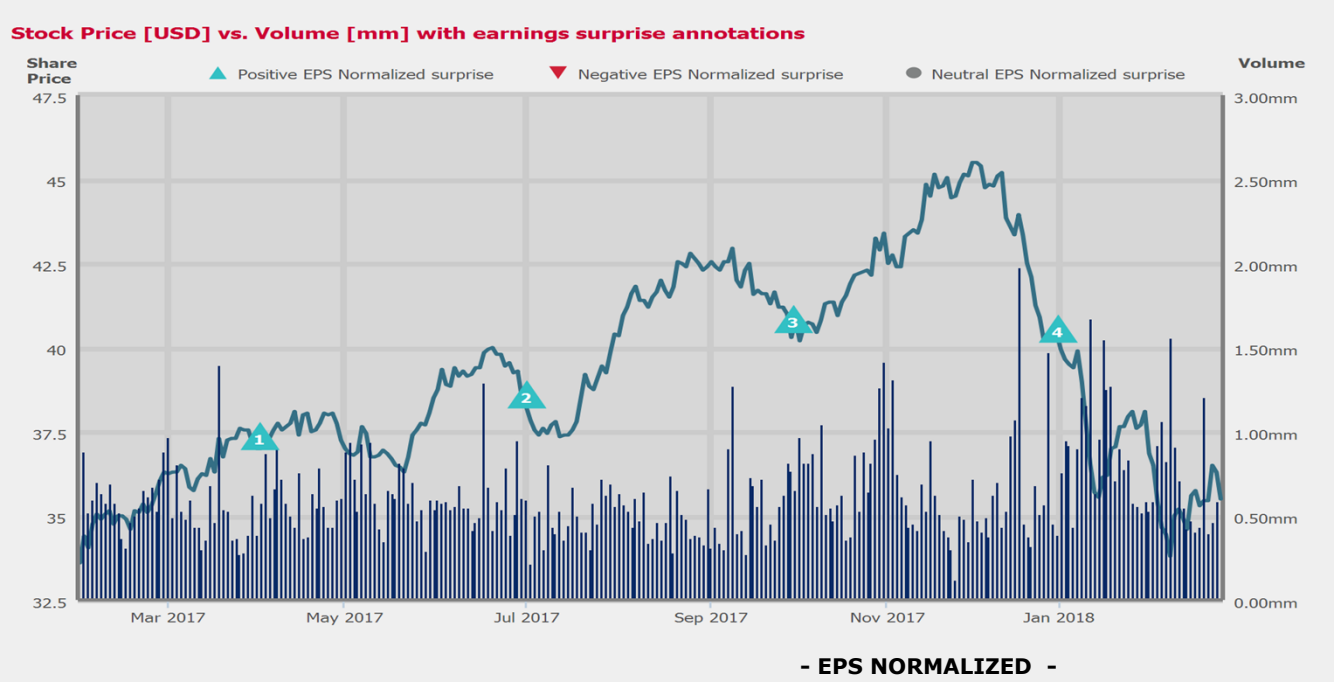
FQ1 2018 Earnings Call Transcripts

Friday, April 27, 2018 3:00 PM GMT

S&P Capital IQ Estimates

	-FQ1 2018-			-FQ2 2018-	-FY 2018-	-FY 2019-
	CONSENSUS	ACTUAL	SURPRISE	CONSENSUS	CONSENSUS	CONSENSUS
EPS Normalized	0.21	0.21	0.00	0.53	1.85	2.07
Revenue	-	-	23.48	-	-	-
Revenue (mm)	257.44	317.88	-	385.60	1468.36	1509.32

Currency: USD
Consensus as of Apr-24-2018 1:00 PM GMT



- EPS NORMALIZED -

	CONSENSUS	ACTUAL	SURPRISE
FQ1 2017	0.24	0.28	1 16.67 %
FQ2 2017	0.45	0.49	2 8.89 %
FQ3 2017	0.85	0.93	3 9.41 %
FQ4 2017	0.19	0.24	4 26.32 %

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Presentation

Operator

Good morning, and welcome to the PNM Resources First Quarter Conference Call. [Operator Instructions] Please note that this event is being recorded. I would now like to turn the conference over to Jimmie Blotter, Director of Investor Relations. Please go ahead.

Jimmie Blotter
Director of Investor Relations and Shareholder Services

Thank you, Cole, and thank you, everyone, for joining us this morning for the PNM Resources' First Quarter 2018 Earnings Conference Call. Please note that the presentation for this conference call and other supporting documents are available on our website at pnmresources.com.

Joining me today are PNM Resources' Chairman, President and CEO, Pat Vincent-Collawn; and Chuck Eldred, our Executive Vice President and Chief Financial Officer; as well as several other members of our executive management team.

Before I turn the call over to Pat, I need to remind you that some of the information provided this morning should be considered forward-looking statements pursuant to the Private Securities Litigation Reform Act of 1995. We caution you that all of the forward-looking statements are based upon current expectations and estimates and that PNM Resources assumes no obligation to update this information. For a detailed discussion of factors affecting PNM Resources' results, please refer to our current and future annual reports on Form 10-K, quarterly reports on Form 10-Q as well as reports on Form 8-K filed with the SEC.

And with that, I will turn the call over to Pat.

Patricia K. Vincent-Collawn
Chairman, President & CEO

Thank you, Jimmie. Good morning, everyone. And yes, it is another beautiful sunny Friday in New Mexico, and it's also Arbor Day, so Happy Arbor Day. Thank you for joining us today for our first quarterly earnings call of 2018.

Let's start on Slide 4, with the financial results and some company updates. Our GAAP earnings per share in the first quarter of 2018 were $0.19. Ongoing earnings per share were consistent with the quarterly expectation of guidance at $0.21 compared to $0.28 in the first quarter of last year. We are also affirming guidance for both 2018 and 2019. I'll turn it over to Chuck to go through the details of these results in just a few minutes.

As we work our way through 2018, we are expecting a straightforward year. At PNM, our general rate settlement is now behind us and our retail customers are already benefiting from tax reform savings. The phase and approach from our rate case creates a transitional year in 2018 and the full implementation in 2019 supports our 2-year plan.

We weren't surprised this month that the commission did not move forward with our proposal for smart meters in New Mexico. In a state where the economy continues to [light] the nation, no one likes the prospect of job losses. We are encouraged, however, by the commission's inclusion of our proposal for a pilot program in our next energy efficiency filing. This demonstrates the desire to integrate this type of technology in New Mexico in the future. We continue to await a decision from the New Mexico Supreme Court on the appeal of certain items disallowed from our September 2016 general rate case order. This could be issued any day.

We announced our plan to transition out of coal generation last year, and we are moving forward with those plans. We issued an All Source RFP, and we'll consider a variety of resource possibilities to facilitate our goal to achieve a cleaner generation portfolio. It will take some time to thoroughly vet and evaluate the proposal before making an abandonment file next year.

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As a condition to the BART settlement, we will make a compliance filing later this year on our intentions for the retirement of San Juan, but it's too early to look at the details for replacement power.

At TNMP, January TCOS filing was approved in March and rates were implemented March 27. The filing reflected an annual increase of 600,000, which updates our transmission rates for investments that were made through December and for the impact of lowering the income tax rate on all our transmission investments.

We are still on track to file our general rate case in May, and we'll have more information for you once we make the filing. We continue to expect new rates to be implemented in January of 2019 and to return to our to typical twice annual TCOS filings in 2019.

With that, I'll turn it over to Chuck for a detailed look at the numbers.

Charles N. Eldred
Executive VP & CFO

Thank you, Pat, and good morning, everyone. And thank you for joining us today. Let's start with a review of the load on Slide 6.

Beginning the discussion with New Mexico. Economic conditions continue to be stable. The 12-month rolling average employment growth has been consistent for nearly a year now, although it remains lower than the national average. We continue to see economic activity such as the construction work at the Facebook data center. They announced last year that their site will grow from 2 buildings to 6 and have anywhere from 800 to 1,000 workers on site each day due to the construction work.

We also see commercial expansion from restaurants, retail and other activities such as a 200-room hotel scheduled to open at the Santa Ana Casino in July and the construction of 3 new projects to support new apartments, a hotel and retail shops, bringing more than 11,000 -- 1,100 construction jobs and 425 permanent jobs to Albuquerque.

Along with this activity, we're seeing customer growth at 0.7% for the first quarter 2018. This is a slight increase over the level we saw last year.

While PNM's weather-normalized load is consistent with our expectations, the first quarter has a smaller impact on earnings because of the seasonality in our business and, therefore, has less of an impact on the load forecast for the year. As a result, we continue to believe that we will achieve our annual forecast of flat to down 0.7% at PNM.

Economic growth in Texas continues to outpace the rest of the country. We also see strong demand in our service territories, particularly with interconnection requests in our West Texas region. We have started the year strong for both the volumetric and demand-base load, exceeding the forecasted range. But as I mentioned with PNM, given that it's the first quarter, we continue to hold through our annual forecast for TNMP load as well.

Now turning to Slide 7 for the first quarter earnings. As Pat indicated, ongoing earnings per share were in line with our expectations at $0.21. Throughout 2018, our results will reflect the final implementation of the 2015 BART settlement, which were included in the rate case final order that became effective earlier this year. This reflects both the shutdown of San Juan Unit 2 and 3 and Palo Verde Unit 3 serving retail customers. As you're aware, the final order also reflects the giveback of tax reform to our customers. While these are sizable items in our earnings drivers, they are largely offsetting each other.

Other elements that caused changes to PNM's earnings include expected items such as the outage of Four Corners to install the SCR equipment, depreciation and property tax from our capital investments and load. We've talked for some time now that if Palo Verde 3 becomes a jurisdictional resource that we would also move our nuclear decommissioning trust to a heavier weighting of fixed income assets now that it's tied to assets funded by rate payers. Partially offsetting these items are weather that was closer to normal and transmission margins.

TNMP is up $0.03 due largely to load and the revenue from TCOS filings implemented last year.

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Finally, Corporate and Other was down $0.02 for interest expense and other items.

Our March 9, we issued $300 million of fixed-rate notes. This result in the holding company now having little exposure to variable rates.

Now let's turn to Slide 8. The 2018 guidance continues to be $1.82 to $1.92, and the first quarter results were in line with our expectations. 2019 remains at $2.04 to $2.16. Our guidance ranges provide the basis to achieve the 6% earnings growth target that we have for 2018 to 2021. We also expect our dividend to grow at a comparable rate to earnings.

The chart at the bottom of this slide has an updated quarterly distribution charge for 2018. San Juan Unit 1 had a failure in its coal silo that has the unit offline at this time. As a result, we moved up the maintenance outage that was expected to occur this fall so that we don't have to take that unit down later.

We have also shifted expenses between the second and fourth quarters. The outage schedule that is in the appendix has been updated as well.

Before I wrap up my comments, I want to mention that when we file the TNMP rate review towards the end of May, we will issue a press release with the details.

Now I'll turn it back over to Pat.

Patricia K. Vincent-Collawn
Chairman, President & CEO

Thanks, Chuck. As we wrap up today and look ahead to the second quarter and our general rate case at TNMP, I want to acknowledge that TNMP was recently honored as an ENERGY STAR partner of the year for 2017 for recognition of the sustained excellence of its energy efficiency programs. This is not the first time TNMP has been awarded this honor, so I want to congratulate our team in Texas for achieving this recognition once again.

Along with that, I said earlier that today is Arbor Day, but I didn't mention that our TNMP employees are commemorating the day again this year by planting trees.

April is also National Volunteer Month, and our employees in New Mexico and Texas are some of the best volunteers I've seen, and I'm not the only one taking notice. Earlier this month, the mayor of Albuquerque recognized the PNM Community Crew as the 2018 Corporate Volunteer Group of the Year.

As I've said before, it's truly an honor working alongside so many individuals that are committed to making our communities better.
Thank you again for joining us today. With that, I'll ask our operator, Cole, to open it up for questions.

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Question and Answer

Operator

[Operator Instructions] And the first question comes from Nick Campanella from Bank of America.

Nicholas Joseph Campanella
BofA Merrill Lynch, Research Division

Can you remind us when you're filing for AMI again? I'm sorry if I missed that.

Patricia K. Vincent-Collawn
Chairman, President & CEO

It's in the next energy efficiency filing that we make.

Nicholas Joseph Campanella
BofA Merrill Lynch, Research Division

Got it. And then keeping with the Arbor Day theme here, just looking at replacement power for San Juan. What are you guys thinking of in terms of fuel mix? I know that your thoughts there can be changing based on cost efficiencies.

Charles N. Eldred
Executive VP & CFO

Yes, Nick, the current capital budget reflects gas units, 2 large frame units of 374 megawatts and 82 megawatts of reciprocating engines. But as Pat pointed out, we have an RFP process going on now that would fine-tune exactly what we view to be the right mix of generations, so it's likely to include some energy storage as a possibility and maybe some renewables along with some peaking units. So that we really won't know the detail to that until probably around the mid-part of 2019.

Nicholas Joseph Campanella
BofA Merrill Lynch, Research Division

Got it. And then just in terms of recovery for that spend. Your peers in New Mexico recently had an order in which new generation they had to operate as merchant initially. Can you just kind of talk about the recovery path there? Obviously, there's a lot of company-specific factors that come into play with these proceedings, but I'm just trying to get an idea of how that all plays out.

Patricia K. Vincent-Collawn
Chairman, President & CEO

Nick, you said about SPS, and I think that you said the keywords there, the company-specific factors. SPS files under historical test year. We file under a future test year. And so I think they wanted to recovery some of that lag there before they got it into their rate base. Anything we do is under a future test year, so theoretically, we don't have that lag. And Nick, the other thing is our next energy efficiency filling is in the spring of 2020. I forgot to tell you that.

Operator

And the next question comes from Ali Agha from SunTrust.

Ali Agha
SunTrust Robinson Humphrey, Inc., Research Division

First, Chuck, can you just remind us, I recall the tax reform impact has been phased in over the 2 years. Specifically, what's the impact to earnings in '18 and '19? I'm assuming by '19, it's neutral, but can you just remind us the tax reform earnings impact?

Charles N. Eldred

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Executive VP & CFO

Yes, Ali. If you look in the appendix of the slide, I think it's on Page 12, in the actual -- not appendix but in the presentation, we show the tax reform to be about $0.04 in 2018 for the first.

Ali Agha
SunTrust Robinson Humphrey, Inc., Research Division

Yes, that was for the -- for the first quarter, right?

Charles N. Eldred
Executive VP & CFO

For the first quarter. And then for the year, you'd have to actually go back to look at some of the fourth quarter earnings review and get the details, which we show you the amount of tax reform for the full year of '18 over '17 is $0.25. And that's -- if you go back to the materials that we posted previously in the fourth quarter on Page 23.

Ali Agha
SunTrust Robinson Humphrey, Inc., Research Division

Yes, yes, got it. Secondly, Pat or Chuck, again, what is the cause for this difference between your customer growth in New Mexico and the load, which continues to be negative? What's the persistent disconnect between the two of them right now?

Charles N. Eldred
Executive VP & CFO

Well, really, the growth is not -- at 0.7%, it's still not substantive enough to impact the load to be positive, so to speak, because of the offset of energy efficiency and distributed generation. So it just kind of at a point where we still see it relatively flat to a slight increase, but just down enough on the customer side to really see a significant positive and/or benefit offsetting energy efficiency in BG.

Ali Agha
SunTrust Robinson Humphrey, Inc., Research Division

I see. And then I believe it's 3, but a bunch of commission seats are up for election this November. Any sense or any expectation of a change to the commission composition post the November election?

Patricia K. Vincent-Collawn
Chairman, President & CEO

Ali, I think it's too soon to tell. Commissioner Lyons is obviously term limited out, so we know we will have a new commissioner there. Commissioner Jones and Commissioner Lovejoy both have challengers in their primaries. But the campaigns are just getting started here. They really kind of start in earnest maybe in the middle of May. So we could have up to 3 new seats or we could have just one. But whoever it is, we look forward to working with them.

Ali Agha
SunTrust Robinson Humphrey, Inc., Research Division

Right. Last question, you talked about the 6% CAGR you are targeting '18 through '21. But when you look at the profile, you have that big jump in '19, so '19 through '21, we're looking at slightly more flattish or smaller growth of earnings. How are you looking at sort of the longer-term picture once we get the full year impact in '19 behind us?

Charles N. Eldred
Executive VP & CFO

We're really -- we're going to focus on the 6% from '18 through '21. And then beyond that really is going to depend on outcome relative to the replacement power of San Juan. So even though it's in the capital budget and we have it in our projections, currently until we fine-tune exactly what that replacement power

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mix is and the recoverability of those costs, we really don't want to speculate on growth beyond 2021. But I feel encouraged by the opportunities we have, so don't take that message as we're concerned. We're just not wanting to speculate on information till we get a little further along as to the details of what that replacement power looks like.

Operator

And the next question comes from Greg Gordon from Evercore ISI.

Durgesh Chopra
Evercore ISI, Research Division

It's actually Durgesh on for Greg. Two quick questions. One, first for you, Pat. The Supreme Court deal, I missed the earlier part of the call. Did you guys discuss what a timeline might be? I know there's no statutory timeline, but is there an expectation on when you could potentially get a decision, whether it's this year or next year?

Patricia K. Vincent-Collawn
Chairman, President & CEO

Well, I think I said we're waiting. We're waiting anxiously. The court had said last year that anything that was in before October, they'd hope to get out by March. And they did do that with the Supreme Court appeal of the BART case, which the court ruled in our favor. And that came out in the beginning of March. This case is complicated. The court doesn't have a lot of utility cases. So literally, I think it's every Monday and Wednesday when the -- excuse me -- Monday and Thursday when the dockets come out. So the team is checking every day. So we're hopeful that we'll be soon, but as you said, there's no time to frame.

Durgesh Chopra
Evercore ISI, Research Division

Okay. And then just on the like the low growth in Texas. I think Ali was asking -- asked you a question on New Mexico. The Texas load growth seems very robust. I just was wondering if with the growth that you're experiencing, is there potential upside into your CapEx? What I mean there is -- could you -- I don't know what -- if you could articulate what assumptions are built -- have you built into your Texas CapEx plan? And that CapEx plan could be higher if you keep seeing a level of growth that you're seeing in Texas.

Charles N. Eldred
Executive VP & CFO

Yes, it's still -- we've actually contributed more to the capital budget to reflect a significant growth in the Permian Basin area even though all of the areas that we cover in Texas are seeing strong growth. The Permian Basin is still a very robust area. So at this point, we update our annual budget in December in that time frame, so it's too early to tell whether or not we see a continued growth. But if we see opportunities, we'll certainly wanting to contribute more capital to support the growth in Texas. But it's just too early at this point, Durgesh, to comment any more other than we are contributing significant amount of capital to support the growth that we see today.

Operator

And the next question comes from Paul Fremont from Mizuho.

Paul Basch Michael Fremont
Mizuho Securities USA LLC, Research Division

Can you discuss at all the Facebook data center power needs and whether they're going to be coming out with some additional RFPs for generation?

Charles N. Eldred
Executive VP & CFO

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Yes. They've already -- we start out with 50 megawatts, which PNM is providing a build on that. In addition to that, the commission approved 3 other different sources of renewables that are pursuing -- being pursued right now, one of which is 50 megawatts of what's referred to a Casa Mesa, which is a wind PPA. Another 166 megawatts of wind, which is another PPA supported by Avangrid. And then there's a 50 megawatts of solar PPA from NextEra. And they're currently looking at some additional solar, anywhere from 50 to 100 megawatts. It's not clear exactly what that will be. And we're actively involved with that discussion to look at the possibility of serving that from PNM's build opportunity.

Paul Basch Michael Fremont
Mizuho Securities USA LLC, Research Division

And would you be doing that on your own or would you be doing that in partnership with somebody?

Charles N. Eldred
Executive VP & CFO

We'll look at it both ways, but certainly, we would look at the JV we have with AAP to support that as well.

Paul Basch Michael Fremont
Mizuho Securities USA LLC, Research Division

And then, can you also just update us on sort of the current outstanding under the Westmoreland note and when that is expected to pay off?

Charles N. Eldred
Executive VP & CFO

Yes. The note itself is around $50 million outstanding, but we do have a $10 million reserve in the San Juan coal company structure that could be applied to that in the event that we need to pay that down further. The note itself, I think, comes due in 2020, '21.

Patricia K. Vincent-Collawn
Chairman, President & CEO

'21.

Charles N. Eldred
Executive VP & CFO

And so we're on track. They're making their payments. As we've said before, the San Juan coal company is bankruptcy remote and [indiscernible] and very secure to how we capture the cash flows and waterfall the excess cash to pay down the debt. So it's been right on schedule, right on plan. And I know they're going through restructuring, so there's a possibility they may decide to pay off that debt, which is fine, too, if they end up in that decision, but that's where it is right now.

Operator

[Operator Instructions] And the next question comes from Lasan Johong from Auvila Research Consulting.

Lasan A. Johong
Auvila Research Consulting LLC

I'm a little confused. Why would the outage for the scrubber installation be considered a normal part of operations? I mean, it sounds like you guys are going to do a scrubber installation every year, is that right?

Patricia K. Vincent-Collawn
Chairman, President & CEO

I think what we're trying to say, Lasan, is that an outage is normal course of business, so we just moved it around and moved it up from the fall into the spring, okay. It's not atypical when you -- when something happens at a plant to move an outage up. I think that the scrubber outage is at Four Corners, we were

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talking about at San Juan because we have the issue with the coal mill. We moved that outage up to the spring.

Lasan A. Johong
Auvila Research Consulting LLC

Okay. So the outage is not impact -- I thought -- I forgot who said that, but I thought the inbound impact on PNM's financial -- first quarter financials was due to the scrubber installation. I think that's what you said in the call.

Charles N. Eldred
Executive VP & CFO

Yes. Last year, we did it. This is the outage we have for the first quarter to reflect the Four Corners installation of the SCRs. So it happened in first quarter last year. So that's that [indiscernible].

Lasan A. Johong
Auvila Research Consulting LLC

Okay. That was last year. I was wondering what was the [indiscernible]

Charles N. Eldred
Executive VP & CFO

Yes.

Patricia K. Vincent-Collawn
Chairman, President & CEO

And then the outage that we moved up, and Chuck said normal course of businesses, is the San Juan outage. Sorry, too many coal plants up in the Four Corners area.

Lasan A. Johong
Auvila Research Consulting LLC

I apologize I missed. I thought it was [indiscernible]

Charles N. Eldred
Executive VP & CFO

It's okay.

Patricia K. Vincent-Collawn
Chairman, President & CEO

No problem.

Charles N. Eldred
Executive VP & CFO

That's all right. No problem.

Lasan A. Johong
Auvila Research Consulting LLC

Okay. Second, right now, natural gas prices are still kind of -- shall we say, on the weaker side, and there's no kind of expectations for anything dramatically to the upside for a very, very long time. So are you feeling any pressure to say, abandon building new topline facilities in this billion sub market and buying power to replace San Juan? So cheap.

Patricia K. Vincent-Collawn
Chairman, President & CEO

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No. I think if you look at that, the San Juan replacement isn't until '21 and 2022. You always buy a little bit of the market. But the market is tight in the west as people retire their coal plants. And some of the natural gas capacity we need is for peaking and for quick-start resources to follow all of that solar generation. And quite frankly, the cheap natural gas prices are what is driving the shutdown of San Juan because the economics for natural gas and renewables are compelling. So we haven't seen that here yet.

Lasan A. Johong
Auvila Research Consulting LLC

Don't get me wrong. I would love to see you guys build a couple of big CCGTs. But I'm just wondering how feasible that might be in the current environment. Third, I know this is kind of a weird question, but when do you expect -- when does New Mexico expect that load growth will turn back towards that positive number again? There a lot of the other utilities saying the effects of energy efficiency have kind of substantially waned, but apparently that's not the case in New Mexico. So I'm kind of wondering when the catch-up will occur.

Patricia K. Vincent-Collawn
Chairman, President & CEO

Well, that's a great question, Lasan. And I think there's a couple of things going on. As Chuck mentioned, we're seeing a lot of small commercial and other growth. There are some nice things in the economic development pipeline, which obviously we can't talk about. But I think if you look at New Mexico, there is a real culture towards the environment and energy efficiency. We are, for example, in Albuquerque, the #1 market in the United States for green-built homes, and so things are built pretty tightly here. And energy efficiency is a good thing. We're in the midst of a proceeding to talk about some sort of a loss revenue adjustment or decoupling that came out of the rate case to give us a volume true-up mechanism because if customers use less energy, it's good for the environment. And if we're held for that, it's okay for us and shareholders. So we hope our economy does pick up, and we see a lot of good things going on. The trick, I think, is just to come up with an energy efficiency disincentive mechanism that works.

Charles N. Eldred
Executive VP & CFO

And Lasan, just to add to that. We do see in 2019 the potential to begin to see a positive growth up to 0.5% in the load forecast for PNM. So again, it could be slightly negative but beginning to see inching into some positive load growth in 2019 as a potential.

Lasan A. Johong
Auvila Research Consulting LLC

Okay. That answer was a fantastic answer because you set me up for my next question. When do you expect or -- well, maybe I shouldn't say when, but in the past, revenue decoupling was really not a priority. But it sounds like that's kind of changing for PNM. And if that's the case, kind of how much of earnings do you see in this? And when do you expect to make any kind of filings to get that done?

Patricia K. Vincent-Collawn
Chairman, President & CEO

We had actually filed in the last rate case for a decoupling mechanism. We were asked to move it out of the rate case into a separate proceeding, which we did. And on March 2, we filed for an approval of a disincentive mechanism with the PRC. And on April 25 of this year, the hearing examiner issued a procedural schedule. So there will be a technical conference and testimony and then there's going to be a hearing on October 31 of this year. So that got moved outside of the rate case, which I think is a good place for it to be outside of the rate case.

Lasan A. Johong
Auvila Research Consulting LLC

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I agree, I agree with what you said. Is there any kind of resistance, or is there a lot of people saying that this is free money to utility, don't do it? How are you doing this? Or how do you position this with the regulators? And do you see resistance, a lot of it?

Patricia K. Vincent-Collawn
Chairman, President & CEO

No. I think the discussion is over what mechanism is appropriate. There's a lot of different opinions on what kind of a mechanism makes sense. Is it a full decoupling? Is it a lost revenue, a true-up? And with the fact that we have a forward test year, right, we true up our volumes every couple of years. So I think most -- everybody realizes that energy efficiency can cause load growth, that we're a high fixed cost business. And obviously, somebody that says we shouldn't have a mechanism, but I think most of the discussion is going to be around what's the appropriate mechanism.

Lasan A. Johong
Auvila Research Consulting LLC

Okay. So it's a matter of if -- a matter of how, not if?

Patricia K. Vincent-Collawn
Chairman, President & CEO

I think so.

Charles N. Eldred
Executive VP & CFO

Yes. Well, I think that one of the hearing examiners that addressed in the last rate case literally laid out the steps of the framework, the methodology that Pat refers to. And we filed our information to reflect that. So we think we're off to a good discussion and to get input, and it's probably more about the methodology than it is whether it's justified.

Lasan A. Johong
Auvila Research Consulting LLC

That's great. Last question is, Chuck, you had mentioned rolling out some potentially new power generation facilities. I would assume, correct me if I'm wrong, that the approval of those facilities will also coincide with the recovery for -- a revenue mechanism recovery for those power plants, correct?

Patricia K. Vincent-Collawn
Chairman, President & CEO

Well, there's 2 parts of this. When we shut down San Juan, we said we make a filing this year, a compliance filing, that reaffirms our intent to shut down San Juan. And then next year, we will make a formal filing for the abandonment of San Juan. And for a CCN, for the new generation, so then we will ask for what recovery mechanism in that CCN filing, but that's next year.

Lasan A. Johong
Auvila Research Consulting LLC

And so that -- and that should guarantee -- there should be no question about what your rate of return will be on these plants going forward?

Charles N. Eldred
Executive VP & CFO

Yes, I mean, it's just more of a question of this is what we feel is -- makes the most sense to address reliability and the changes to the system to integrating with the additional renewables that we're getting onto the system, and it's a question of what that right mix is, whether we own or there's PPAs or whatever the circumstances are. But we feel very comfortable that, to address reliability, particularly on peaking units, you need to have control of those resources.

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Lasan A. Johong
Auvila Research Consulting LLC

Absolutely. I'd just leave it with that. Just wondering if the revenue recovery mechanism and the amounts would be preapproved so that there's no question to the investors that the IRR that you will be receiving on these power plants are fixed and according to the regulated authorized rates.

Charles N. Eldred
Executive VP & CFO

Well, the CCN will address what the resources are that's agreed and approved by the commission, and then we will just file that in our next rate case, which would remove any uncertainty. It's a question at that point of getting that into our rates after the CCN is approved. So it does remove the uncertainty, yes.

Operator

And that concludes our question-and-answer session. I would like to turn the conference back to Pat Vincent-Collawn for any closing remarks.

Patricia K. Vincent-Collawn
Chairman, President & CEO

Thank you, Cole. Thank you all again for joining us this morning. Please have a happy Arbor Day. And if you plant any trees, please remember to take care of your backs. And we will talk to you all again soon. Thank you.

Operator
The conference has now concluded. Thank you for attending today's presentation. You may now disconnect.

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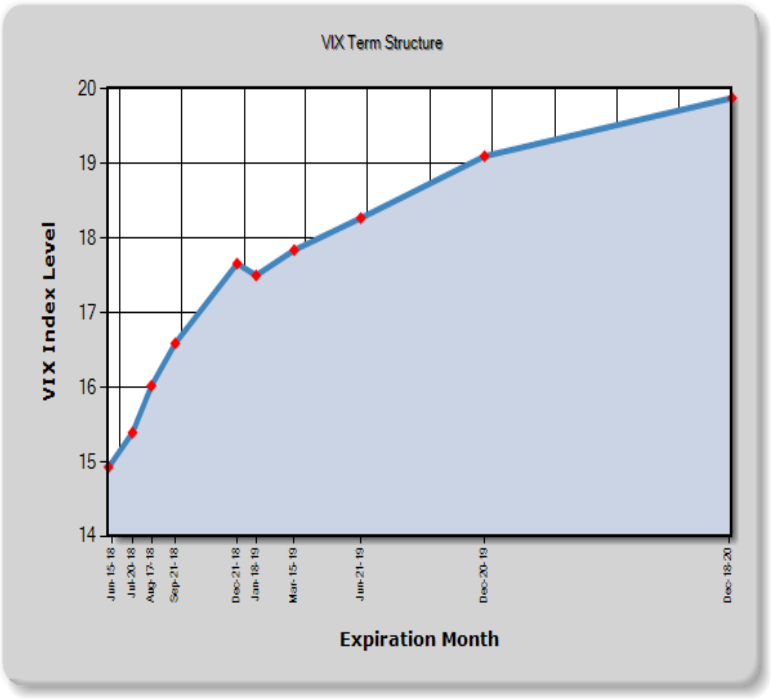

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5/31/2018 2:44:29 PM	21-Sep-18	16.59	4
5/31/2018 2:44:29 PM	21-Dec-18	17.66	5
5/31/2018 2:44:29 PM	18-Jan-19	17.50	6
5/31/2018 2:44:30 PM	15-Mar-19	17.84	7
5/31/2018 2:44:29 PM	21-Jun-19	18.27	8
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Browser & System Requirements

Markets Division

Contact

ALLETE NYSE-ALE

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
67.19	21.6 (Trailing: 21.5 Median: 16.0)	1.13	3.4%	

TIMELINESS 3 Lowered 1/26/18
SAFETY 2 New 10/1/04
TECHNICAL 2 Raised 3/2/18
BETA .75 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+10%)	6%
Low	55	(-20%)	-1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	8	0	0	1	0	0	0	8
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	140	118	117
to Sell	108	124	98
Hld's(000)	43781	44573	38769

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
High:	51.3	49.0	35.3	37.9	42.5	42.7	54.1	58.0	59.7	66.9	81.2	74.4								
Low:	38.2	28.3	23.3	30.0	35.1	37.7	41.4	44.2	45.3	48.3	61.6	66.6								
	--	--	25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	30.27	27.01	27.78	*28.45*	*28.85*	Revenues per sh	*30.75*
	--	--	2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	6.79	7.08	6.59	*7.00*	*7.35*	"Cash Flow" per sh	*8.50*
	--	--	1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	3.38	3.14	3.13	*3.40*	*3.60*	Earnings per sh [A]	*4.25*
	--	--	.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	2.02	2.08	2.14	*2.24*	*2.34*	Div'd Decl'd per sh [B] ■ †	*2.70*
	--	--	2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	5.84	5.35	4.08	*6.25*	*6.80*	Cap'l Spending per sh	*6.25*
	--	--	21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	37.07	38.17	40.47	*42.10*	*43.80*	Book Value per sh [C]	*49.25*
	--	--	29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	49.10	49.60	51.10	*52.00*	*53.00*	Common Shs Outst'g [D]	*56.00*
	--	--	25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	15.1	18.6	23.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.0*
	--	--	1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	.76	.98	1.14			Relative P/E Ratio	*.85*
	--	--	.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	4.0%	3.6%	3.0%			Avg Ann'l Div'd Yield	*4.2%*
							801.0	759.1	907.0	928.2	961.2	1018.4	1136.8	1486.4	1339.7	1419.3	*1480*	*1530*	Revenues ($mill)	*1725*
							82.5	61.0	75.3	93.8	97.1	104.7	124.8	163.4	155.3	159.2	*175*	*190*	Net Profit ($mill)	*235*
							34.3%	33.7%	37.2%	27.6%	28.1%	21.5%	22.6%	19.4%	11.3%	14.8%	*NMF*	*Nil*	Income Tax Rate	*Nil*
							5.8%	12.8%	8.9%	2.7%	5.3%	4.4%	6.3%	2.0%	1.4%	.8%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
							41.6%	42.8%	44.2%	44.3%	43.7%	44.6%	44.2%	46.3%	42.0%	41.0%	*40.5%*	*38.5%*	Long-Term Debt Ratio	*38.0%*
							58.4%	57.2%	55.8%	55.7%	56.3%	55.4%	55.8%	53.7%	58.0%	59.0%	*59.5%*	*61.5%*	Common Equity Ratio	*62.0%*
							1415.4	1625.3	1747.6	1937.2	2134.6	2425.9	2882.2	3388.9	3263.4	3507.4	*3685*	*3785*	Total Capital ($mill)	*4450*
							1387.3	1622.7	1805.6	1982.7	2347.6	2576.5	3286.4	3669.1	3741.2	3822.4	*3960*	*4120*	Net Plant ($mill)	*4275*
							6.7%	4.8%	5.4%	6.0%	5.6%	5.3%	5.2%	5.8%	5.8%	5.5%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
							10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.5%*
							10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	*8.0%*	*8.0%*	Return on Com Equity [E]	*8.5%*
							3.9%	.5%	1.5%	2.9%	2.3%	2.2%	2.5%	3.6%	2.8%	2.4%	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
							61%	93%	81%	66%	71%	72%	67%	60%	66%	68%	*66%*	*65%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $1503.3 mill. **Due in 5 Yrs** $450.5 mill.
LT Debt $1439.2 mill. **LT Interest** $61.9 mill.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $14.2 mill.

Pension Assets-12/17 $628.2 mill.
Oblig $793.2 mill.

Pfd Stock None

Common Stock 51,143,656 shs.
as of 2/1/18
MARKET CAP: $3.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-8.9	-2.3	+8.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.40	NA	NA
Capacity at Peak (Mw)	1942	NA	NA
Peak Load, Winter (Mw)	1631	1520	1599
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	381	318	339

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	1.0%	2.5%	*1.5%*
"Cash Flow"	5.0%	7.5%	*3.5%*
Earnings	1.5%	5.5%	*4.5%*
Dividends	3.5%	3.0%	*4.5%*
Book Value	6.0%	6.0%	*4.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2015	320.0	323.3	462.5	380.6	1486.4
2016	333.8	314.8	349.6	341.5	1339.7
2017	365.6	353.3	362.5	337.9	1419.3
2018	*370*	*360*	*390*	*360*	*1480*
2019	*380*	*375*	*400*	*375*	*1530*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2015	.85	.46	1.23	.83	3.38
2016	.93	.50	.81	.89	3.14
2017	.97	.72	.88	.56	3.13
2018	*1.00*	*.60*	*.95*	*.85*	*3.40*
2019	*1.05*	*.65*	*1.00*	*.90*	*3.60*

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.49	.49	.49	.49	1.96
2015	.505	.505	.505	.505	2.02
2016	.52	.52	.52	.52	2.08
2017	.535	.535	.535	.535	2.14
2018	.56				

LEGENDS
0.73 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2021 | 2022 | 2023

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.5	10.1
3 yr.	38.0	24.2
5 yr.	73.9	76.2

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 26%; paper/wood products, 9%; other industrial, 8%; residential, 12%; commercial, 13%; wholesale, 16% other, 16%. ALLETE Clean Energy owns renewable energy projects. Acq'd U.S. Water Services 2/15. Has real estate operation in FL. Generating sources: coal & lignite, 41%; wind, 12%; other, 6%; purchased, 41%. Fuel costs: 28% of revs. '17 deprec. rate: 3.2%. Has 2,000 employees. Chairman, President & CEO: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's main utility subsidiary received a disappointing rate decision. Minnesota Power had sought a rate increase of $55 million (8.6%), based on a 10.25% return on a 53.8% common-equity ratio. The state commission (through a verbal order) granted a hike of $13 million (2.0%), based on a 9.25% return on the same common-equity ratio. Minnesota Power expected to receive a written order shortly after our report went to press, and plans to decide what steps it will take once management reviews the order.

We think earnings will advance solidly in 2018. Minnesota Power should benefit from healthy industrial demand for power. The utility is also earning a return on the construction work in progress for a transmission line that is scheduled for completion in 2020. ALLETE's wind-energy subsidiary should benefit from increased production and the construction and sale of a 50-megawatt project to a utility in North Dakota. U.S. Water Services is seeing rising demand for its water-treatment services and a full year of revenues from an acquisition it made last September. Our 2018 share-earnings estimate is within ALLETE's targeted range of $3.20-$3.50. Note that the company's profits in the fourth quarter of 2017 benefited from the revaluation of deferred taxes due to the new federal tax law. This added $0.25 a share to the bottom line, which we excluded as a nonrecurring item.

We forecast solid profit growth next year. The factors that are likely to help earnings in 2018 should be present in 2019, as well. We look for a 6% increase in share net, which is within ALLETE's annual growth goal of 5%-7%.

The board of directors raised the dividend in the first quarter. The annual increase was $0.10 a share (4.7%), a greater hike than in recent years. The accelerated growth rate is in line with the company's expectation of faster profit growth. ALLETE is targeting a payout ratio of 60%-65%.

This stock's dividend yield is close to the average for electric utility equities. With the recent quotation above the midpoint of our 3- to 5-year Target Price Range, total return potential is unappealing.

Paul E. Debbas, CFA *March 16, 2018*

(A) Diluted EPS. Excl. nonrec. gain (losses): '04, (25¢); '05, ($1.84); '15, (46¢); '17, 25¢; gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢). '15 & '16 EPS don't sum due to rounding. Next earnings report due early May. **(B)** Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. **(C)** Incl. deferred charges. In '17: $11.95/sh. **(D)** In mill. **(E)** Rate base: Orig. cost depr. Rate allowed in MN on com. eq. in '18: 9.25%; earned on avg. com. eq., '17: 8.6%. Regulatory Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	85

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ALLIANT ENERGY NYSE-LNT

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
38.17	17.7 (Trailing: 19.2 Median: 15.0)	0.93	3.5%	

TIMELINESS 2 Raised 3/9/18
SAFETY 2 Raised 9/28/07
TECHNICAL 3 Lowered 3/2/18
BETA .70 (1.00 = Market)

2021-23 PROJECTIONS

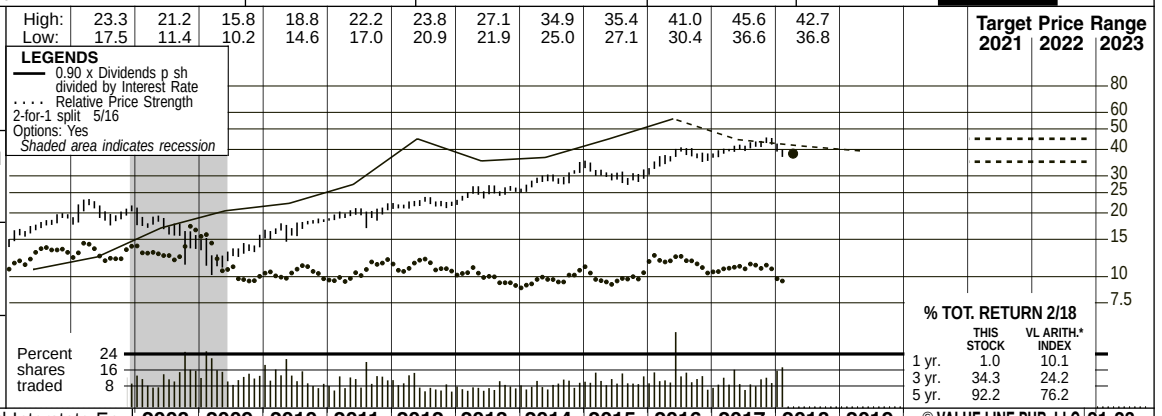
	Price	Gain	Ann'l Total Return
High	45	(+20%)	8%
Low	35	(-10%)	2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	1	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	1	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	198	194	190
to Sell	188	187	165
Hld's(000)	179256	182717	166325



Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share.

© VALUE LINE PUB. LLC	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	21-23
Revenues per sh	16.67	15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	14.62	*15.30*	*15.55*	*17.75*
"Cash Flow" per sh	2.28	2.10	2.60	2.75	2.95	3.34	3.44	3.45	3.45	3.97	*4.25*	*4.45*	*5.00*
Earnings per sh [A]	1.27	.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	1.99	*2.10*	*2.25*	*2.60*
Div'd Decl'd per sh [B] ■ †	.70	.75	.79	.85	.90	.94	1.02	1.10	1.18	1.26	*1.34*	*1.42*	*1.66*
Cap'l Spending per sh	3.98	5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	6.34	*6.75*	*7.10*	*5.30*
Book Value per sh [C]	12.78	12.54	13.05	13.57	14.12	14.79	15.54	16.41	16.96	18.08	*19.00*	*20.25*	*22.85*
Common Shs Outst'g [D]	220.90	221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	231.35	*233.00*	*235.00*	*235.00*
Avg Ann'l P/E Ratio	13.4	13.9	12.5	14.5	14.5	15.3	16.6	18.1	22.3	20.6	*Bold figures are Value Line estimates*		*15.0*
Relative P/E Ratio	.81	.93	.80	.91	.92	.86	.87	.91	1.17	1.01			*.85*
Avg Ann'l Div'd Yield	4.1%	5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%	3.1%			*4.3%*
Revenues ($mill)	3681.7	3432.8	3416.1	3665.3	3094.5	3276.8	3350.3	3253.6	3320.0	3382.2	*3560*	*3650*	*4175*
Net Profit ($mill)	280.0	208.6	303.9	304.4	337.8	382.1	385.5	380.7	373.8	455.9	*490*	*530*	*610*
Income Tax Rate	33.4%	- -	30.1%	19.0%	21.5%	12.4%	10.1%	15.3%	13.4%	12.5%	*12.0%*	*12.0%*	*12.0%*
AFUDC % to Net Profit	- -	- -	- -	- -	- -	- -	- -	6.5%	7.0%	*7.0%*	*7.0%*	*7.0%*	*7.0%*
Long-Term Debt Ratio	36.3%	44.3%	46.3%	45.7%	48.4%	46.1%	49.7%	48.6%	52.8%	49.0%	*50.0%*	*50.0%*	*50.0%*
Common Equity Ratio	58.6%	51.2%	49.5%	50.9%	48.4%	50.8%	47.5%	51.4%	47.2%	51.0%	*50.0%*	*50.0%*	*50.0%*
Total Capital ($mill)	4815.6	5423.0	5840.8	5921.2	6476.6	6461.0	7257.2	7246.3	8177.6	8192.8	*8300*	*8400*	*8700*
Net Plant ($mill)	5353.5	6203.0	6730.6	7037.1	7838.0	7147.3	6442.0	8970.2	9809.9	10797.9	*11125*	*11645*	*12900*
Return on Total Cap'l	7.0%	5.1%	6.6%	6.4%	6.3%	7.0%	6.3%	6.3%	5.6%	5.6%	*6.0%*	*6.5%*	*7.0%*
Return on Shr. Equity	9.1%	6.9%	9.7%	9.5%	10.1%	11.0%	10.6%	10.2%	9.7%	10.9%	*11.0%*	*11.0%*	*11.5%*
Return on Com Equity [E]	9.3%	6.8%	9.9%	9.5%	10.3%	11.3%	10.9%	10.2%	9.7%	10.9%	*11.0%*	*11.0%*	*11.5%*
Retained to Com Eq	3.8%	.9%	3.8%	3.3%	3.9%	4.9%	4.3%	3.6%	2.8%	4.0%	*4.0%*	*4.0%*	*4.0%*
All Div'ds to Net Prof	62%	88%	64%	67%	64%	57%	59%	65%	72%	63%	*64%*	*63%*	*64%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $5186.5 mill. **Due in 5 Yrs** $1500.0 mill.
LT Debt $4010.6 mill. **LT Interest** $180.0 mill.
(LT interest earned: 4.0x)

Pension Assets-12/17 $950.7 mill. **Oblig.** $1303.1 mill.
Pfd Stock $400.0 mill. **Pfd Div'd** $10.2 mill.
16,000,000 shs.

Common Stock 231,348,646 shs.

MARKET CAP: $8.8 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.1	+2.0	1.0
Avg. Indust. Use (MWH)	11735	11987	12102
Avg. Indust. Revs. per KWH (¢)	6.92	7.04	7.16
Capacity at Peak (Mw)	5385	5615	5375
Peak Load, Summer (Mw)	5385	5615	5375
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+1.0	+.4
Fixed Charge Cov. (%)	315	295	319

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '21-'23
Revenues	.5%	-1.5%	*3.0%*
"Cash Flow"	3.5%	6.5%	*5.5%*
Earnings	5.0%	6.5%	*6.5%*
Dividends	7.5%	6.5%	*6.0%*
Book Value	4.0%	4.5%	*5.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	897.4	717.2	898.9	740.1	3253.6
2016	843.8	754.2	925.0	797.0	3320.0
2017	853.9	765.3	906.9	856.1	3382.2
2018	*950*	*790*	*945*	*875*	*3560*
2019	*960*	*815*	*975*	*900*	*3650*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.44	.30	.80	.15	1.69
2016	.43	.37	.57	.28	1.65
2017	.44	.41	.73	.41	1.99
2018	*.50*	*.40*	*.85*	*.35*	*2.10*
2019	*.53*	*.43*	*.90*	*.39*	*2.25*

QUARTERLY DIVIDENDS PAID [B] ■†

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.255	.255	.255	.255	1.02
2015	.275	.275	.275	.275	1.10
2016	.295	.295	.295	.295	1.18
2017	.315	.315	.315	.315	1.26
2018	.335				

BUSINESS: Alliant Energy Corp., formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity, gas, and other services in Wisconsin, Iowa, and Minnesota. Elect. revs. by state: WI, 38%; IA, 61%; MN, 1%. Elect. rev.: residential, 36%; commercial, 24%; industrial, 30%; wholesale, 8%; other, 2%. Fuel sources, 2017: coal, 40%; gas, 17%; other, 43%. Fuel costs: 45% of revs. 2017 depreciation rate: 5.5%. Estimated plant age: 15 years. Has approximately 3,989 employees. Chairman & Chief Executive Officer: Patricia L. Kampling. Incorporated: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy's largest utility subsidiary has reached a settlement of its rate case. Under the agreement, electric rates for Interstate Power and Light Company (IPL) would rise $130 million (7.8%) in 2018. That is down from the original $176 million (11.6%) request, but within our range of estimates. The Iowa Utilities Board also approved a return on common equity of 9.6% and said that temporary rates, which have been in effect since April 2017, would remain until the board reviews and approves tariff filings to be made by Alliant. The company said it would use the funds to upgrade power grids and improve facilities like the Marshalltown natural gas generating station.

Earnings should advance in 2018 and 2019. Each year, the utility is expected to benefit from electric and gas rate increases at IPL and Wisconsin Power and Light Company (WPL). Our 2018 profit estimate is near the midpoint of management's guidance range of $2.04-$2.18 a share, while our 2019 estimate calls for 7% year-on-year growth. It should be noted that tax reform is not forecasted to have a material impact on earnings. This is because much of the anticipated savings will be returned to customers through fewer/lower rate increases over time.

Wind energy remains an area of focus for Alliant. In December, the utility agreed to purchase English Farms Wind Farm for an undisclosed sum. The 170-megawatt, Iowa-based project is expected to power approximately 75,000 homes upon completion. Alliant is aiming to generate at least one-third of its Iowa energy mix from wind starting in 2020.

The board raised the dividend in the first quarter of 2018. This is the usual timing of the annual increase. The directors boosted the yearly disbursement by $0.08 a share (6.3%), the same increase as in each of the past four years. Alliant is targeting a payout ratio of 60%-70%.

This good-quality stock is well ranked for year-ahead relative price performance. The dividend yield is slightly below the median for a utility. Appreciation potential, while improved since our December report, is still well below the *Value Line* median. Accordingly, we advise long-term investors to wait on the sidelines.

Daniel Henigson *March 16, 2018*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '08, 4¢; '09, (44¢); '10, (8¢); '11, (1¢); '12, (8¢). Next earnings report due early May. **(B)** Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. **(C)** Incl. deferred chgs. In '17: $69.7 mill., $0.30/sh. **(D)** In millions, adjusted for split. **(E)** Rate base: Orig. cost. Rates all'd on com. eq. in IA in '17: 10.5%; in WI in '17 Regul. Clim.: WI, Above Avg.; IA, Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	90

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AMEREN NYSE-AEE

RECENT PRICE **53.94** | P/E RATIO **17.7** (Trailing: 19.4 Median: 15.0) | RELATIVE P/E RATIO **0.93** | DIV'D YLD **3.5%** | **VALUE LINE**

TIMELINESS 2 Raised 3/2/18
SAFETY 2 Raised 6/20/14
TECHNICAL 3 Lowered 2/23/18
BETA .65 (1.00 = Market)

2021-23 PROJECTIONS

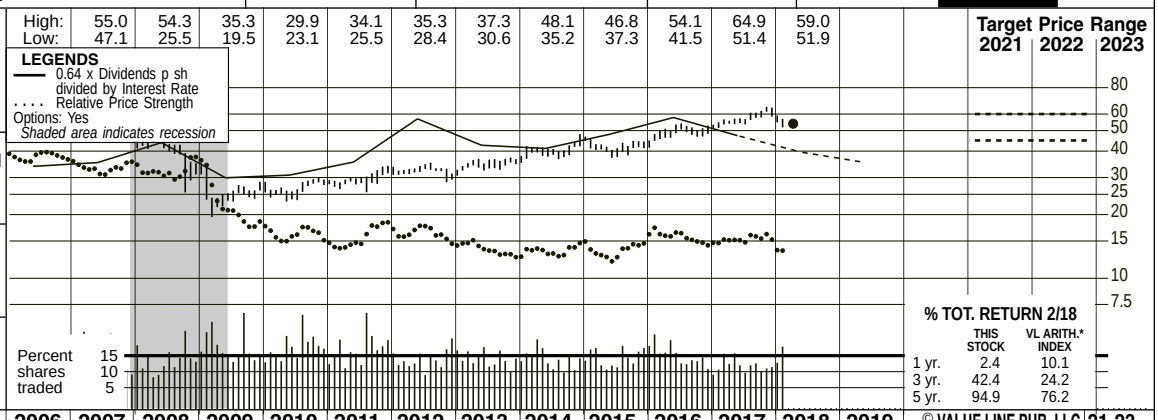
	Price	Gain	Ann'l Total Return
High	60	(+10%)	*6%*
Low	45	(-15%)	*Nil*

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	0	0	0	0	0	21
to Sell	0	1	0	0	0	0	1	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	247	229	212
to Sell	209	215	192
Hld's(000)	185587	186752	171005



2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
24.93	28.20	26.43	33.12	33.30	36.23	36.92	29.87	31.77	31.04	28.14	24.06	24.95	25.13	25.04	25.46	***25.20***	***25.85***	Revenues per sh	***28.00***
5.28	6.29	5.57	6.10	6.02	6.76	6.44	6.06	6.33	5.87	5.87	5.25	5.77	6.08	6.59	6.80	***7.35***	***7.85***	"Cash Flow" per sh	***9.25***
2.66	3.14	2.82	3.13	2.66	2.98	2.88	2.78	2.77	2.47	2.41	2.10	2.40	2.38	2.68	2.77	***3.05***	***3.25***	Earnings per sh [A]	***3.75***
2.54	2.54	2.54	2.54	2.54	2.54	2.54	1.54	1.54	1.56	1.60	1.60	1.61	1.66	1.72	1.78	***1.85***	***1.93***	Div'd Decl'd per sh [B] ■	***2.25***
5.11	4.19	4.13	4.63	4.99	6.96	9.75	7.51	4.66	4.50	5.49	5.87	7.66	8.12	8.78	9.05	***9.80***	***10.45***	Cap'l Spending per sh	***8.50***
24.93	26.73	29.71	31.09	31.86	32.41	32.80	33.08	32.15	32.64	27.27	26.97	27.67	28.63	29.27	29.61	***31.00***	***32.45***	Book Value per sh [C]	***37.25***
154.10	162.90	195.20	204.70	206.60	208.30	212.30	237.40	240.40	242.60	242.63	242.63	242.63	242.63	242.63	242.63	***244.00***	***245.50***	Common Shs Outst'g [D]	***250.00***
15.8	13.5	16.3	16.7	19.4	17.4	14.2	9.3	9.7	11.9	13.4	16.5	16.7	17.5	18.3	20.6	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	***14.5***
.86	.77	.86	.89	1.05	.92	.85	.62	.62	.75	.85	.93	.88	.88	.96	1.02			Relative P/E Ratio	***.80***
6.1%	6.0%	5.5%	4.9%	4.9%	4.9%	6.2%	6.0%	5.8%	5.3%	5.0%	4.6%	4.0%	4.0%	3.5%	3.1%			Avg Ann'l Div'd Yield	***4.2%***
7839.0	7090.0	7638.0	7531.0	6828.0	5838.0	6053.0	6098.0	6076.0	6177.0	***6150***	***6350***	Revenues ($mill)	***7000***
615.0	624.0	669.0	602.0	589.0	518.0	593.0	585.0	659.0	683.0	***755***	***805***	Net Profit ($mill)	***950***
33.7%	34.7%	36.8%	37.3%	36.9%	37.5%	38.9%	38.3%	36.7%	38.2%	***22.0%***	***22.0%***	Income Tax Rate	***22.0%***
4.6%	5.8%	7.8%	5.6%	6.1%	7.1%	5.7%	5.1%	4.1%	3.5%	***4.0%***	***4.0%***	AFUDC % to Net Profit	***3.0%***
47.8%	49.7%	48.2%	45.3%	49.5%	45.2%	47.2%	49.3%	47.7%	49.2%	***49.5%***	***49.0%***	Long-Term Debt Ratio	***49.5%***
50.8%	49.1%	50.9%	53.7%	49.4%	53.7%	51.7%	49.7%	51.3%	49.8%	***49.5%***	***50.0%***	Common Equity Ratio	***50.0%***
13712	15991	15185	14738	13384	12190	12975	13968	13840	14420	***15225***	***15925***	Total Capital ($mill)	***18600***
16567	17610	17853	18127	16096	16205	17424	18799	20113	21466	***22800***	***24225***	Net Plant ($mill)	***27100***
5.7%	5.3%	6.0%	5.6%	6.0%	5.6%	5.8%	5.3%	6.0%	5.9%	***6.0%***	***6.0%***	Return on Total Cap'l	***6.5%***
8.6%	7.8%	8.5%	7.5%	8.7%	7.7%	8.7%	8.3%	9.1%	9.3%	***10.0%***	***10.0%***	Return on Shr. Equity	***10.0%***
8.7%	7.8%	8.6%	7.5%	8.8%	7.8%	8.7%	8.3%	9.2%	9.4%	***10.0%***	***10.0%***	Return on Com Equity [E]	***10.0%***
1.0%	3.5%	3.8%	2.8%	3.0%	1.9%	2.9%	2.5%	3.3%	3.4%	***4.0%***	***4.0%***	Retained to Com Eq	***4.0%***
88%	56%	56%	63%	66%	76%	67%	70%	64%	64%	***61%***	***60%***	All Div'ds to Net Prof	***60%***

CAPITAL STRUCTURE as of 12/31/17
Total Debt $8419 mill. **Due in 5 Yrs** $2862 mill.
LT Debt $7094 mill. **LT Interest** $348 mill.
(LT interest earned: 4.2x)
Leases, Uncapitalized Annual rentals $10 mill.
Pension Assets-12/17 $4293 mill.
Oblig $4827 mill.
Pfd Stock $142 mill. **Pfd Div'd** $6 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 616,323 sh. 4.00% to 6.625%, $100 par, redeem. $100-$104/sh.
Common Stock 242,634,798 shs. **as of 1/31/18**
MARKET CAP: $13 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-1.1	-4.2	-3.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	343	351	362

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-3.0%	-3.5%	*2.0%*
"Cash Flow"	.5%	1.5%	*6.5%*
Earnings	-1.0%	.5%	*7.5%*
Dividends	-4.0%	2.0%	*4.5%*
Book Value	-1.0%	-1.0%	*4.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1556	1401	1833	1308	6098.0
2016	1434	1427	1859	1356	6076.0
2017	1514	1538	1723	1402	6177.0
2018	***1500***	***1500***	***1750***	***1400***	***6150***
2019	***1550***	***1550***	***1800***	***1450***	***6350***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.45	.40	1.41	.12	2.38
2016	.43	.61	1.52	.13	2.68
2017	.42	.79	1.18	.39	2.77
2018	***.55***	***.70***	***1.40***	***.40***	***3.05***
2019	***.60***	***.70***	***1.50***	***.45***	***3.25***

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.40	.40	.40	.41	1.61
2015	.41	.41	.41	.425	1.66
2016	.425	.425	.425	.44	1.72
2017	.44	.44	.44	.4575	1.78
2018	.4575				

BUSINESS: Ameren Corporation is a holding company formed through the merger of Union Electric and CIPSCO. Acq'd CILCORP 1/03; Illinois Power 10/04. Has 1.2 mill. electric and 127,000 gas customers in Missouri; 1.2 mill. electric and 813,000 gas customers in Illinois. Discontinued nonregulated power-generation operation in '13. Electric rev. breakdown: residential, 46%; commercial, 35%; industrial, 8%; other, 11%. Generating sources: coal, 71%; nuclear, 19%; hydro & other, 4%; purchased, 6%. Fuel costs: 27% of revs. '17 reported deprec. rates: 3%-4%. Has 8,600 employees. Chairman, President & CEO: Warner L. Baxter. Inc.: MO. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, MO 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

We think Ameren's earnings will exceed the $3.00-a-share level in 2018. The company will benefit from a full year's effect of the rate increase that took effect in Missouri at the start of April of 2017. A return to normal weather patterns would help after unfavorable weather was a drag on profits last year. The Callaway nuclear facility will not have a refueling outage this year. The refinancing of debt will boost earnings. Our earnings estimate is at the midpoint of Ameren's targeted range of $2.95-$3.15 a share. Note that the 2017 tally was depressed by the revaluation of deferred taxes, which stemmed from the new federal tax law. This forced Ameren to take a nonrecurring charge of $0.63 a share in the fourth quarter.

We forecast further profit growth in 2019. One factor that boosts Ameren's earning power annually is the utility's investment in electric transmission. There is still uncertainty about what the allowed return on equity will be—the Federal Energy Regulatory Commission must still issue a ruling on this—but this will still exceed the allowed ROEs in Missouri and Illinois. Our 2019 earnings estimate indicates profit growth of 7%, which is within management's annual goal of 5%-7%.

Will 2018 be the year in which a regulatory law is passed in Missouri? Utilities in the state have been hurt by regulatory lag because Missouri uses a historical test year and doesn't use a lot of mechanisms that allow for concurrent recovery of certain kinds of capital spending or expenses. The state senate has passed a bill that would be beneficial for utilities in this regard. If the bill is enacted into law, Ameren will boost its capital spending in the state, with an estimated $1 billion for grid modernization through 2023.

Ameren filed a gas rate application in Illinois. The utility requested a $49 million increase, based on a 10.3% return on a 50% common-equity ratio. A ruling is expected in late 2018, with new tariffs taking effect in January of 2019.

This timely stock has a dividend yield that is about average, by utility standards. Like many utility equities, the recent quotation is within our 3- to 5-year Target Price Range. Accordingly, total return potential over that time frame is low.

Paul E. Debbas, CFA *March 16, 2018*

(A) Dil. EPS. Excl. nonrec. gain (losses): '05, (11¢); '10, ($2.19); '11, (32¢); '12, ($6.42); '17, (63¢); gain (loss) from disc. ops.: '13, (92¢); '15, 21¢. '16-'17 EPS don't sum due to rounding. Next egs. report due early May. **(B)** Div'ds histor. paid in late Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. **(C)** Incl. intang. In '17: $6.76/sh. **(D)** In mill. **(E)** Rate base: Orig. cost depr. Rate all'd on com. eq. in MO in '17: elec., none spec.; in '11: gas, none spec.; in IL in '14: elec., 8.7%, in '16: gas, 9.6%; earned on avg. com. eq., '17: 7.3%. Reg. Climate: Below Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	80

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RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
65.50	16.5 (Trailing: 18.1 Median: 14.0)	0.86	3.9%	

TIMELINESS 3 Lowered 1/19/18
SAFETY 1 Raised 3/17/18
TECHNICAL 3 Lowered 2/3/18
BETA .65 (1.00 = Market)

2021-23 PROJECTIONS

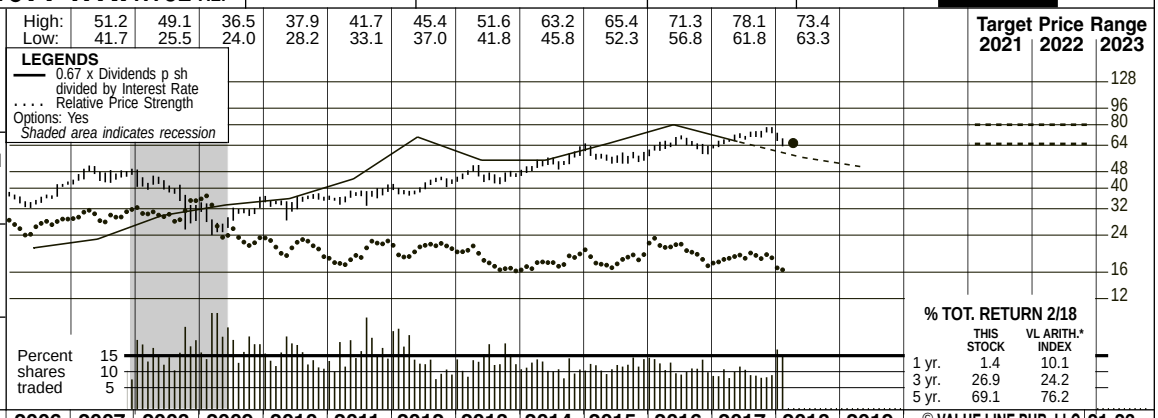
	Price	Gain	Ann'l Total Return
High	80	(+20%)	9%
Low	65	(Nil)	4%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	9	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	376	388	371
to Sell	369	351	342
Hld's(000)	384520	382879	352776



2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	33.51	33.31	31.35	*30.60*	*31.30*	Revenues per sh	*33.00*
6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	7.98	8.47	7.95	*8.30*	*8.60*	"Cash Flow" per sh	*9.50*
2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.59	4.23	3.62	*3.90*	*4.10*	Earnings per sh A	*5.00*
2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	2.39	*2.51*	*2.63*	Div'd Decl'd per sh B ■	*3.05*
5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	9.37	9.98	11.79	*12.50*	*12.95*	Cap'l Spending per sh	*11.25*
20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	37.17	*38.70*	*40.25*	Book Value per sh C	*46.75*
338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	492.01	*493.50*	*495.00*	Common Shs Outst'g D	*516.00*
12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	15.8	15.2	19.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*14.5*
.69	.61	.66	.73	.70	.87	.79	.67	.85	.75	.88	.81	.84	.80	.80	.96			Relative P/E Ratio	*.80*
6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	3.5%	3.4%			Avg Ann'l Div'd Yield	*4.2%*
14440	13489	14427	15116	14945	15357	17020	16453	16380	15425	*15100*	*15500*	Revenues ($mill)	*17000*
1208.0	1365.0	1248.0	1513.0	1443.0	1549.0	1634.0	1763.4	2073.6	1783.2	*1870*	*1960*	Net Profit ($mill)	*2490*
31.3%	29.7%	34.8%	31.7%	33.9%	36.2%	37.8%	35.1%	26.8%	33.7%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
9.9%	10.9%	10.4%	10.6%	11.2%	7.3%	9.0%	11.0%	8.0%	8.0%	*11.0%*	*10.0%*	AFUDC % to Net Profit	*6.0%*
59.1%	54.4%	53.1%	50.7%	50.6%	51.1%	49.0%	49.8%	50.0%	51.5%	*52.5%*	*54.5%*	Long-Term Debt Ratio	*50.5%*
40.7%	45.4%	46.7%	49.3%	49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	*47.5%*	*45.5%*	Common Equity Ratio	*49.5%*
26290	28958	29184	29747	30823	32913	33001	35633	34775	37707	*40325*	*43775*	Total Capital ($mill)	*48800*
32987	34344	35674	36971	38763	40997	44117	46133	45639	50262	*54250*	*58450*	Net Plant ($mill)	*68700*
6.2%	6.2%	5.7%	6.6%	6.1%	6.0%	6.3%	6.1%	7.2%	5.9%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
11.2%	10.3%	9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
11.3%	10.4%	9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	*10.0%*	*10.0%*	Return on Com Equity E	*10.5%*
5.1%	4.6%	3.1%	4.2%	3.5%	3.7%	3.8%	3.9%	5.5%	3.2%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
55%	56%	66%	60%	63%	62%	61%	60%	54%	67%	*66%*	*66%*	All Div'ds to Net Prof	*63%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $22812 mill. **Due in 5 Yrs** $9694 mill.
LT Debt $19420 mill. **LT Interest** $874 mill.
Incl. $1410.5 mill. securitized bonds. Incl. $294 mill. capitalized leases.
(LT interest earned: 3.8x)
Leases, Uncapitalized Annual rentals $245.9 mill.
Pension Assets-12/17 $5174.1 mill.
Oblig $5215.8 mill.
Pfd Stock None

Common Stock 492,005,598 shs.

MARKET CAP: $32 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-1.2	+.3	-1.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	NA	NA
Fixed Charge Cov. (%)	356	374	354

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	- -	1.5%	*Nil*
"Cash Flow"	2.5%	4.0%	*2.5%*
Earnings	3.0%	5.5%	*4.5%*
Dividends	4.0%	4.5%	*5.0%*
Book Value	4.0%	4.0%	*4.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	4580	3827	4431	3615	16453
2016	4045	3893	4652	3790	16380
2017	3933	3577	4105	3810	15425
2018	*3850*	*3450*	*4100*	*3700*	*15100*
2019	*4000*	*3650*	*4200*	*3650*	*15500*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.27	.88	1.04	.41	3.59
2016	1.02	1.03	1.43	.76	4.23
2017	.94	.76	1.11	.81	3.62
2018	*1.10*	*.80*	*1.25*	*.75*	*3.90*
2019	*1.15*	*.85*	*1.30*	*.80*	*4.10*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.50	.50	.50	.53	2.03
2015	.53	.53	.53	.56	2.15
2016	.56	.56	.56	.59	2.27
2017	.59	.59	.59	.62	2.39
2018	.62				

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves 5.4 mill. customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Electric revenue breakdown: residential, 40%; commercial, 23%; industrial, 19%; wholesale, 15%; other, 3%. Sold SEEBOARD (British utility) '02; Houston Pipeline '05; commercial barge operation in '15. Generating sources not available. Fuel costs: 34% of revenues. '17 reported depreciation rates (utility): 1.6%-9.2%. Has 17,700 employees. Chairman, President & CEO: Nicholas K. Akins. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

American Electric Power's earnings will likely advance solidly in 2018 and 2019. The company's utilities are benefiting from rate relief. Public Service of Oklahoma received an $84 million rate increase (before passing through to customers the reduction in federal taxes), based on a 9.3% return on equity. Also this quarter, SWEPCo was granted a hike of $50 million, based on a 9.6% ROE. Indiana & Michigan has rate cases pending in each state. In Indiana, the utility reached a settlement (subject to approval by the state commission) for an increase of $97 million, based on a 9.95% ROE. New tariffs would take effect in mid-2018. In Michigan, I&M requested a $52 million hike, based on a 10.6% ROE. An order is expected in April. Heavy investment in electric transmission (some $3 billion annually) is also expanding the company's earning power. Our 2018 and 2019 share-earnings estimates are within AEP's targeted ranges of $3.75-$3.95 and $4.00-$4.20, respectively.

The company wants to build a large wind project to serve four states. The 2,000-megawatt facility would cost $4.5 billion and would be completed by the fourth quarter of 2020. This needs the approval of the state commissions in Oklahoma, Arkansas, Texas, and Louisiana. (Opposition to the project has emerged in Oklahoma.) Rulings on the proposals are expected by the end of April.

AEP no longer has exposure to the vagaries of the power markets. The company has sold or written off its non-regulated generating facilities. (This caused a large nonrecurring charge in 2016.) It is still seeking a buyer for its remaining generating assets.

Finances are solid. The fixed-charge coverage, common-equity ratio, and earned ROE are healthy. AEP's exit from merchant (uncontracted) power has lowered its business risk, too. The company's Financial Strength rating is A+.

The stock has a dividend yield that is somewhat above the utility average. This might well appeal to conservative investors, given the stock's Safety rank of 1 (Highest). Total return potential to 2021-2023 does not stand out among electric companies, however.

Paul E. Debbas, CFA *March 16, 2018*

(A) Dil. EPS. Excl. nonrec. gains (losses): '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, ($2.99); '17, 26¢; disc. ops.: '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '15, 58¢; '16, (1¢). '15-'16 EPS don't sum due to rounding. Next egs. report due late April. **(B)** Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. **(C)** Incl. intang. In '17: $12.59/sh. **(D)** In mill. **(E)** Rate base: various. Rates all'd on com. eq.: 9.65%-10.9%; earn. on avg. com. eq., '17: 10.0%. Regul. Climate: Avg.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	50
Earnings Predictability	85

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AVISTA CORP. NYSE-AVA

RECENT PRICE **52.18** | P/E RATIO **26.4** (Trailing: 26.8 / Median: 16.0) | RELATIVE P/E RATIO **1.40** | DIV'D YLD **2.9%** | **VALUE LINE**

TIMELINESS — Suspended 7/28/17
SAFETY **2** Raised 5/7/10
TECHNICAL — Suspended 7/28/17
BETA .70 (1.00 = Market)

2021-23 PROJECTIONS

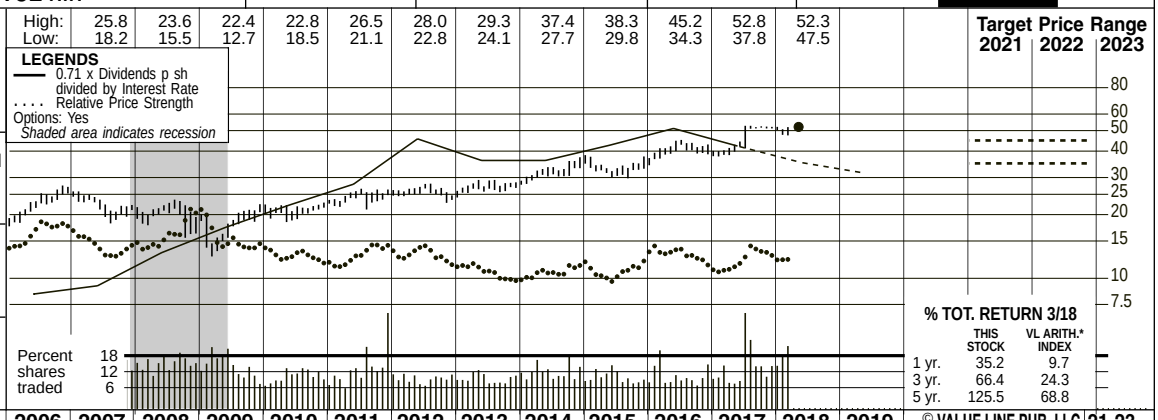
	Price	Gain	Ann'l Total Return
High	45	(-15%)	*Nil*
Low	35	(-35%)	*-5%*

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	9	0	0	0	13	13
to Sell	0	0	0	0	0	3	1	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	122	102	89
to Sell	110	149	92
Hld's(000)	56062	60906	52242



2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
20.41	23.24	23.76	27.98	28.68	26.80	30.77	27.58	27.29	27.73	25.86	26.94	23.66	23.83	22.47	22.08	***22.00***	***22.00***	Revenues per sh	***24.00***
2.19	2.63	2.35	2.72	4.27	2.93	3.98	4.45	3.62	3.78	3.70	4.36	4.36	4.92	5.30	4.87	***5.10***	***5.40***	"Cash Flow" per sh	***6.50***
.67	1.02	.73	.92	1.47	.72	1.36	1.58	1.65	1.72	1.32	1.85	1.84	1.89	2.15	1.95	***1.95***	***2.10***	Earnings per sh [A]	***2.50***
.48	.49	.52	.55	.57	.60	.69	.81	1.00	1.10	1.16	1.22	1.27	1.32	1.37	1.43	***1.49***	***1.55***	Div'd Decl'd per sh [B] ■	***1.67***
1.74	2.21	2.47	3.23	3.14	4.04	4.09	3.86	3.64	4.20	4.61	5.05	5.47	6.46	6.34	6.30	***6.15***	***6.05***	Cap'l Spending per sh	***6.25***
14.84	15.54	15.54	15.87	17.46	17.27	18.30	19.17	19.71	20.30	21.06	21.61	23.84	24.53	25.69	26.41	***26.95***	***27.75***	Book Value per sh [C]	***29.75***
48.04	48.34	48.47	48.59	52.51	52.91	54.49	54.84	57.12	58.42	59.81	60.08	62.24	62.31	64.19	65.49	***67.00***	***68.00***	Common Shs Outst'g [D]	***70.00***
19.3	13.8	24.4	19.4	15.4	30.9	15.0	11.4	12.7	14.1	19.3	14.6	17.3	17.6	18.8	23.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	***15.5***
1.05	.79	1.29	1.03	.83	1.64	.90	.76	.81	.88	1.23	.82	.91	.89	.99	1.18			Relative P/E Ratio	***.95***
3.7%	3.5%	2.9%	3.0%	2.5%	2.7%	3.4%	4.5%	4.8%	4.5%	4.6%	4.5%	4.0%	4.0%	3.4%	3.1%			Avg Ann'l Div'd Yield	***4.3%***
1676.8	1512.6	1558.7	1619.8	1547.0	1618.5	1472.6	1484.8	1442.5	1445.9	***1475***	***1525***	Revenues ($mill)	***1675***
73.6	87.1	92.4	100.2	78.2	111.1	114.2	118.1	137.2	126.1	***130***	***145***	Net Profit ($mill)	***180***
38.3%	34.3%	35.0%	35.4%	34.4%	36.0%	37.6%	36.3%	36.3%	36.5%	***22.5%***	***22.5%***	Income Tax Rate	***22.5%***
14.0%	4.2%	4.0%	5.2%	8.3%	8.8%	11.1%	10.1%	8.1%	7.9%	***9.0%***	***8.0%***	AFUDC % to Net Profit	***7.0%***
48.1%	50.9%	51.6%	51.4%	50.8%	51.4%	51.0%	50.0%	51.2%	47.2%	***50.0%***	***50.0%***	Long-Term Debt Ratio	***48.5%***
51.9%	49.1%	48.4%	48.6%	49.2%	48.6%	49.0%	50.0%	48.8%	52.8%	***50.0%***	***50.0%***	Common Equity Ratio	***51.5%***
1919.5	2139.0	2325.3	2439.9	2561.2	2669.7	3027.3	3060.3	3379.0	3273.2	***3620***	***3770***	Total Capital ($mill)	***4050***
2492.2	2607.0	2714.2	2860.8	3023.7	3202.4	3620.0	3898.6	4147.5	4398.8	***4600***	***4790***	Net Plant ($mill)	***5050***
5.8%	5.5%	5.4%	5.5%	4.3%	5.4%	4.9%	5.1%	5.3%	5.0%	***4.5%***	***5.0%***	Return on Total Cap'l	***5.5%***
7.4%	8.3%	8.2%	8.5%	6.2%	8.6%	7.7%	7.7%	8.3%	7.3%	***7.0%***	***7.5%***	Return on Shr. Equity	***8.5%***
7.4%	8.3%	8.2%	8.5%	6.2%	8.6%	7.7%	7.7%	8.3%	7.3%	***7.0%***	***7.5%***	Return on Com Equity [E]	***8.5%***
3.7%	4.1%	3.3%	3.1%	.8%	2.9%	2.4%	2.3%	3.0%	1.9%	***2.0%***	***2.0%***	Retained to Com Eq	***3.0%***
50%	51%	60%	64%	88%	66%	69%	70%	64%	73%	***75%***	***73%***	All Div'ds to Net Prof	***65%***

CAPITAL STRUCTURE as of 12/31/17
Total Debt $1926.2 mill. **Due in 5 Yrs** $801.3 mill.
LT Debt $1543.3 mill. **LT Interest** $71.1 mill.
Incl. $51.5 mill. debt to affiliated trusts; $62.1 mill. capitalized leases.
(LT interest earned: 3.6x)
Pension Assets-12/17 $605.7 mill.
Oblig $666.5 mill.
Pfd Stock None

Common Stock 65,628,172 shs.
as of 1/31/18

MARKET CAP: $3.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-2.0	-1.2	+4.7
Avg. Indust. Use (MWH)	1339	1314	1367
Avg. Indust. Revs. per KWH (¢)	6.17	6.09	6.11
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.3	+.6	+1.2
Fixed Charge Cov. (%)	315	333	296

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-2.0%	-3.5%	*1.0%*
"Cash Flow"	4.5%	6.5%	*4.5%*
Earnings	7.0%	5.0%	*5.5%*
Dividends	9.0%	5.0%	*4.0%*
Book Value	4.0%	4.5%	*3.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	446.5	337.3	313.7	387.3	1484.8
2016	418.2	318.8	303.4	402.1	1442.5
2017	436.5	314.5	297.1	397.8	1445.9
2018	*430*	*325*	*310*	*410*	*1475*
2019	*445*	*335*	*320*	*425*	*1525*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.74	.40	.21	.54	1.89
2016	.92	.43	.19	.62	2.15
2017	.96	.34	.07	.58	1.95
2018	*.85*	*.40*	*.15*	*.55*	*1.95*
2019	*.90*	*.45*	*.15*	*.60*	*2.10*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.3175	.3175	.3175	.3175	1.27
2015	.33	.33	.33	.33	1.32
2016	.3425	.3425	.3425	.3425	1.37
2017	.3575	.3575	.3575	.3575	1.43
2018	.3725				

BUSINESS: Avista Corporation (formerly The Washington Water Power Company) supplies electricity & gas in eastern Washington & northern Idaho. Supplies electricity to part of Alaska & gas to part of Oregon. Customers: 392,000 electric, 340,000 gas. Acq'd Alaska Electric Light and Power 7/14. Sold Ecova energy-management sub. 6/14. Electric rev. breakdown: residential, 39%; commercial, 32%; industrial, 11%; wholesale, 8%; other, 10%. Generating sources: hydro, 33%; gas & coal, 28%; purch., 39%. Fuel costs: 36% of revs. '17 reported depr. rate (Avista Utilities): 3.1%. Has 2,000 employees. Chairman & CEO: Scott L. Morris. Pres.: Dennis Vermillion. Inc.: WA. Address: 1411 E. Mission Ave., Spokane, WA 99202-2600. Tel.: 509-489-0500. Internet: www.avistacorp.com.

The proposed acquisition of Avista has run into a snag. Hydro One, a Canadian company, has agreed to pay US$53 in cash for each share of Avista. The deal has been approved by shareholders and the Federal Energy Regulatory Commission. It still requires the approval of the regulatory commissions in five states: Washington, Idaho, Oregon, Alaska, and Montana. The companies have reached settlements with the commission's staff and intervenors in Washington, Idaho, and Alaska. However, in Oregon there is opposition to the transaction as currently constructed. However, this is not necessarily a fatal blow. The companies are in settlement talks with the staff and intervenors, and may adjust the structure of the deal to address their concerns. Avista is asking each state for a ruling by August, and expects the combination to be completed in the second half of 2018.

The uncertainty does not appear to be affecting the stock price. At the start of 2018, Avista shares were trading at a 3% discount to the value of Hydro One's offer, and this gap is now 2%. We continue to advise Avista holders to sell their stock on the open market. The Timeliness rank is suspended due to the buyout agreement.

A multiyear rate case is pending in Washington. Increases would take effect on May 1st each year. Avista is seeking electric increases of $54.4 million in 2018, $13.5 million in 2019, and $13.9 million in 2020. The utility is asking for gas hikes of $6.6 million in 2018, $3.7 million in 2019, and $3.8 million in 2020. The company's filing is based on a 9.9% return on a 50% common-equity ratio. The staff of the Washington commission is proposing total electric and gas increases of $33.2 million and $6.7 million, respectively, based on a 9.1% return on a 48.5% common-equity ratio. The commission's ruling was expected shortly after this report went to press. Note that recent rate orders in Washington have been unfavorable for the utility.

We estimate flat earnings in 2018. Rate hikes will help, but Avista is incurring merger-related costs. Tax reform is likely to hurt share net by $0.05-$0.06. If the stock is still trading in 2019, this means the deal fell through, so the absence of merger-related costs should lift profits.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. nonrec. gain (losses): '02, (9¢); '03, (3¢); '14, 9¢; '17, (16¢); gains (losses) on disc. ops.: '02, 2¢; '03, (10¢); '14, $1.17; '15, 8¢. '16 EPS don't sum due to rounding. Next earnings report due early May. **(B)** Div'ds paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. **(C)** Incl. def'd chgs. In '17: $10.43/sh. **(D)** In mill. **(E)** Rate base: Net orig. cost. Rate all'd on com. eq. in WA in '16: 9.5%; in ID in '17: 9.5%; in OR in '15: 9.5%; earn. on avg. com. eq., '17: 7.5%. Regulatory Climate: WA, Avg.; ID, Above Avg.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	60
Earnings Predictability	75

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AVANGRID, INC. NYSE-AGR

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
52.62	22.9 (Trailing: 31.1 Median: NMF)	1.29	3.3%	

TIMELINESS 3 Raised 3/23/18
SAFETY 2 Raised 2/17/17
TECHNICAL 3 Lowered 3/30/18
BETA .40 (1.00 = Market)

2021-23 PROJECTIONS

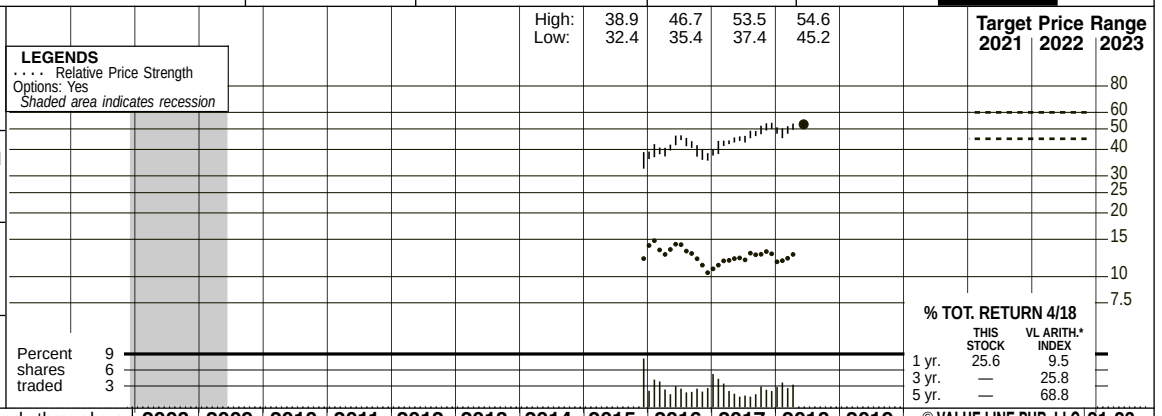
	Price	Gain	Ann'l Total Return
High	60	(+15%)	7%
Low	45	(-15%)	Nil

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	1	1	1	1	1	2	1	1	1
Options	0	0	0	0	1	0	0	0	3
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	119	104	101
to Sell	96	95	69
Hld's(000)	42981	44774	43167



AVANGRID, Inc. was formed through a merger between Iberdrola USA, Inc. and UIL Holdings Corporation in December of 2015. Iberdrola S.A., a worldwide leader in the energy industry, owns 81.5% of AVANGRID. The predecessor company was founded in 1852 and is headquartered in New Gloucester, Maine. It was incorportated in 1997 in New York under the name NGE Resources, Inc. AVANGRID began trading on the NYSE on December 17, 2015.

CAPITAL STRUCTURE as of 3/31/18
Total Debt $6036 mill. **Due in 5 Yrs** $2600 mill.
LT Debt $5160 mill. **LT Interest** $213 mill.
Incl. $74 mill. capitalized leases.
(LT interest earned: 4.0x)
Leases, Uncapitalized Annual rentals $36 mill.

Pension Assets-12/17 $2865 mill.
Oblig $3593 mill.
Pfd Stock None

Common Stock 309,005,272 shs.
as of 5/1/18
MARKET CAP: $16 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	+.5	+.6
Fixed Charge Cov. (%)	183	415	333

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	--	--	4.5%
"Cash Flow"	--	--	8.0%
Earnings	--	--	13.0%
Dividends	--	--	5.0%
Book Value	--	--	1.5%

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1227	939	1048	1153	4367.0
2016	1670	1439	1418	1491	6018.0
2017	1758	1331	1341	1533	5963.0
2018	1865	*1370*	*1370*	*1495*	*6100*
2019	*1875*	*1425*	*1425*	*1575*	*6300*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.42	.04	.22	.37	1.05
2016	.63	.33	.35	.67	1.98
2017	.77	.39	.32	.19	1.67
2018	.79	*.42*	*.37*	*.72*	*2.30*
2019	*.90*	*.45*	*.42*	*.78*	*2.55*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	--	--	--	--	--
2015	--	--	--	--	--
2016	--	.432	.432	.432	1.30
2017	.432	.432	.432	.432	1.73
2018	.432	.432			

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
	--	--	--	--	--	--	--	14.14	19.48	19.30	*19.75*	*20.40*	Revenues per sh	*22.75*
	--	--	--	--	--	--	--	3.44	4.74	4.49	*5.20*	*5.60*	"Cash Flow" per sh	*6.75*
	--	--	--	--	--	--	--	1.05	1.98	1.67	*2.30*	*2.55*	Earnings per sh [A]	*3.25*
	--	--	--	--	--	--	--	--	1.73	1.73	*1.74*	*1.78*	Div'd Decl'd per sh [B] ■	*2.20*
	--	--	--	--	--	--	--	3.50	5.52	7.82	*7.75*	*7.75*	Cap'l Spending per sh	*7.75*
	--	--	--	--	--	--	--	48.74	48.90	48.79	*49.35*	*50.15*	Book Value per sh [C]	*53.25*
	--	--	--	--	--	--	--	308.86	308.99	309.01	*309.00*	*309.00*	Common Shs Outst'g [D]	*309.00*
	--	--	--	--	--	--	--	33.5	20.5	27.3	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
	--	--	--	--	--	--	--	1.69	1.08	1.37	*Value Line*		Relative P/E Ratio	*.85*
	--	--	--	--	--	--	--	--	4.3%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*
	--	--	--	--	--	--	4594.0	4367.0	6018.0	5963.0	*6100*	*6300*	Revenues ($mill)	*7050*
	--	--	--	--	--	--	424.0	267.0	611.0	516.0	*710*	*795*	Net Profit ($mill)	*1025*
	--	--	--	--	--	--	39.9%	11.3%	37.4%	32.4%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
	--	--	--	--	--	--	6.8%	12.7%	7.5%	12.4%	*9.0%*	*8.0%*	AFUDC % to Net Profit	*7.0%*
	--	--	--	--	--	--	16.8%	23.1%	23.0%	25.6%	*28.5%*	*30.0%*	Long-Term Debt Ratio	*36.5%*
	--	--	--	--	--	--	83.2%	76.9%	77.0%	74.4%	*71.5%*	*70.0%*	Common Equity Ratio	*63.5%*
	--	--	--	--	--	--	14956	19583	19619	20273	*21375*	*22200*	Total Capital ($mill)	*26000*
	--	--	--	--	--	--	17099	20711	21548	22669	*24175*	*25625*	Net Plant ($mill)	*29800*
	--	--	--	--	--	--	3.7%	2.1%	3.8%	3.1%	*4.0%*	*4.0%*	Return on Total Cap'l	*4.5%*
	--	--	--	--	--	--	3.4%	1.8%	4.0%	3.4%	*4.5%*	*5.0%*	Return on Shr. Equity	*6.0%*
	--	--	--	--	--	--	3.4%	1.8%	4.0%	3.4%	*4.5%*	*5.0%*	Return on Com Equity [E]	*6.0%*
	--	--	--	--	--	--	3.4%	1.8%	1.4%	NMF	*1.0%*	*1.5%*	Retained to Com Eq	*2.0%*
	--	--	--	--	--	--	--	--	66%	104%	*76%*	*69%*	All Div'ds to Net Prof	*66%*

BUSINESS: AVANGRID, Inc. (formerly Iberdrola USA, Inc.), is a diversified energy and utility company that serves 2.2 million electric customers in New York, Connecticut, and Maine and 1 million gas customers in New York, Connecticut, Massachusetts and Maine. Has a nonregulated generating subsidiary focused on wind power, with 7.1 gigawatts of capacity. Revenue breakdown by customer class not available. Generating sources not available. Fuel costs: 22% of revenues. '17 depreciation rate: 2.9%. Iberdrola owns 81.5% of stock. Has 6,600 employees. Chairman: José Ignacio Sanchez Galan. CEO: James P. Torgerson. Incorporated: New York. Address: 180 Marsh Hill Road, Orange, Connecticut 06477. Telephone: 207-629-1200. Internet: www.avangrid.com.

We estimate that AVANGRID's earnings will advance significantly in 2018 and 2019. The losses from the company's noncore assets that are being sold (see below) will be lower this year than in 2017, and will be eliminated next year. The utilities are benefiting from multiyear electric and gas rate hikes in New York and Connecticut. Additional rate relief should come next year from cases that Connecticut Natural Gas and Berkshire Gas are planning to file soon. The renewable-energy subsidiary is adding wind and solar projects — 590 megawatts in the first quarter of 2018. Our 2018 share-earnings estimate is within AVANGRID's targeted range (on a GAAP basis) of $2.16-$2.46.

AVANGRID has completed the sales of its two noncore units. The company's gas trading and storage businesses have been in the red, and didn't fit management's focus on gas and electric transmission and distribution and renewable energy. The two sales raised a total of $225 million, subject to closing adjustments.

The company has a potentially large electric transmission investment opportunity. Central Maine Power was chosen to construct a transmission line to import hydro power from Quebec after the previously selected project (proposed by Eversource Energy) failed to obtain siting approval in New Hampshire. This $950 million project requires various state and federal regulatory approvals, with construction beginning as early as next year. The line would be in service in 2022, and would be allowed a federally regulated return on equity. This is significant because federally regulated ROEs exceed those allowed by the state commissions in which AVANGRID's utilities operate.

Management has stated its expectation of a dividend hike this year. We look for a slight increase, to $0.44 a share quarterly, in the fourth quarter. We do not rule out a larger (or earlier) raise. Shareholders of AVANGRID (and its predecessor, UIL Holdings) have not seen an increase since the 20th century.

We believe this stock is expensively priced. The recent quotation is well within our 2021-2023 Target Price Range. For the year ahead, the dividend yield is only about average for a utility.

Paul E. Debbas, CFA *May 18, 2018*

(A) Diluted EPS. Excl. nonrecurring gain (loss): '16, 6¢; '17, (44¢). Next earnings report due late July. **(B)** Div'ds paid in early Jan., April, July, and Oct. ■ Dividend reinvestment plan available. **(C)** Incl. intangibles. In '17: $6.2 bill., $20.04/sh. **(D)** In millions. **(E)** Rate base: net original cost. Rate allowed on com. eq. in NY in '16: 9.0%; in CT in '17: 9.1% elec.; in CT in '16: 9.36% gas; in ME in '14: 9.45%; earned on avg. common eq., '17: 3.4%. Regulatory Climate: Below Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	NMF
Earnings Predictability	NMF

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BLACK HILLS CORP. NYSE-BKH

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
54.41	15.9 (Trailing: 16.1 Median: 19.0)	0.85	3.5%	

TIMELINESS 3 Lowered 1/5/18
SAFETY 2 Raised 5/1/15
TECHNICAL 5 Lowered 4/6/18
BETA .90 (1.00 = Market)

2021-23 PROJECTIONS

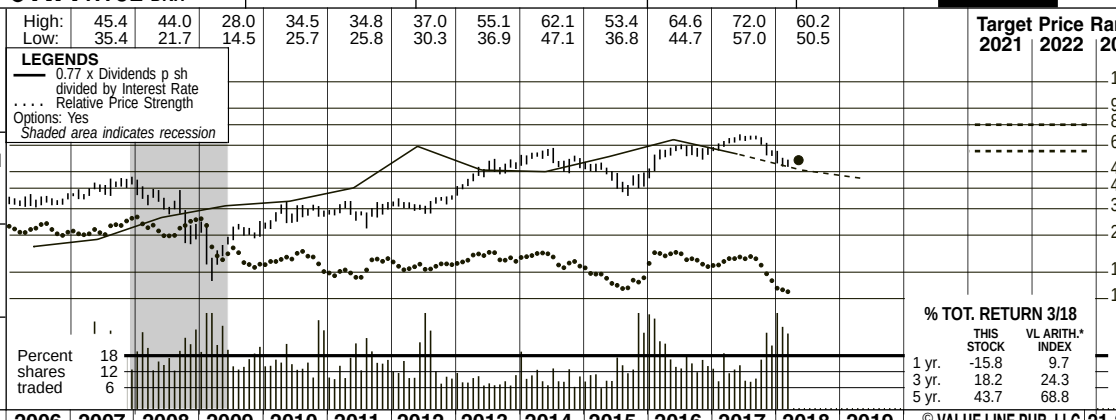
	Price	Gain	Ann'l Total Return
High	80	(+45%)	*13%*
Low	60	(+10%)	*6%*

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	9	6	6	9	6	6	9	6	12
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	143	115	118
to Sell	92	99	85
Hld's(000)	59838	60667	52971



% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-15.8	9.7
3 yr.	18.2	24.3
5 yr.	43.7	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
15.74	35.17	34.54	41.97	19.69	18.41	26.03	32.58	33.29	28.96	26.55	28.67	31.20	25.48	29.47	31.38	*27.75*	*28.55*	Revenues per sh	*32.00*
4.93	4.26	4.46	4.81	5.04	5.29	2.95	5.41	4.88	4.01	5.59	5.93	6.25	5.67	6.28	7.15	*6.75*	*7.25*	"Cash Flow" per sh	*8.50*
2.33	1.84	1.74	2.11	2.21	2.68	.18	2.32	1.66	1.01	1.97	2.61	2.89	2.83	2.63	3.38	*3.45*	*3.55*	Earnings per sh [A]	*4.00*
1.16	1.20	1.24	1.28	1.32	1.37	1.40	1.42	1.44	1.46	1.48	1.52	1.56	1.62	1.68	1.81	*1.90*	*2.02*	Div'd Decl'd per sh [B] ■	*2.45*
8.65	2.80	2.80	4.18	9.24	6.92	8.51	8.90	12.04	10.03	7.90	7.97	8.92	8.90	8.89	6.09	*7.25*	*8.50*	Cap'l Spending per sh	*6.75*
19.66	21.72	22.43	22.29	23.68	25.66	27.19	27.84	28.02	27.53	27.88	29.39	30.80	28.63	30.25	31.92	*35.25*	*36.80*	Book Value per sh [C]	*41.25*
26.93	32.30	32.48	33.16	33.37	37.80	38.64	38.97	39.27	43.92	44.21	44.50	44.67	51.19	53.38	53.54	*59.50*	*59.50*	Common Shs Outst'g [D]	*59.50*
12.5	15.9	17.1	17.3	15.8	15.0	NMF	9.9	18.1	31.1	17.1	18.2	19.0	16.1	22.3	19.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
.68	.91	.90	.92	.85	.80	NMF	.66	1.15	1.95	1.09	1.02	1.00	.81	1.17	.98			Relative P/E Ratio	*.95*
4.0%	4.1%	4.2%	3.5%	3.8%	3.4%	4.2%	6.2%	4.8%	4.6%	4.4%	3.2%	2.8%	3.5%	2.9%	2.7%			Avg Ann'l Div'd Yield	*3.5%*
1005.8	1269.6	1307.3	1272.2	1173.9	1275.9	1393.6	1304.6	1573.0	1680.3	*1650*	*1700*	Revenues ($mill)	*1900*
6.8	89.7	64.6	40.4	86.9	115.8	128.8	128.3	140.3	186.5	*195*	*210*	Net Profit ($mill)	*240*
33.1%	30.7%	26.4%	31.1%	35.5%	34.7%	33.7%	35.8%	25.1%	28.7%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
173.2%	20.1%	28.0%	65.0%	5.4%	2.4%	2.4%	2.7%	5.3%	2.7%	*3.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
32.3%	48.4%	51.9%	51.4%	43.2%	51.6%	47.9%	56.0%	66.5%	64.5%	*58.5%*	*61.0%*	Long-Term Debt Ratio	*54.0%*
67.7%	51.6%	48.1%	48.6%	56.8%	48.4%	52.1%	44.0%	33.5%	35.5%	*41.5%*	*39.0%*	Common Equity Ratio	*46.0%*
1551.8	2100.7	2286.3	2489.7	2171.4	2704.7	2643.6	3332.7	4825.8	4818.4	*5055*	*5600*	Total Capital ($mill)	*5325*
2022.2	2160.7	2495.4	2789.6	2742.7	2990.3	3239.4	3259.1	4469.0	4541.4	*4765*	*5055*	Net Plant ($mill)	*5525*
1.6%	5.9%	4.4%	3.3%	5.5%	5.5%	6.1%	4.9%	4.0%	5.2%	*5.0%*	*5.0%*	Return on Total Cap'l	*6.0%*
.7%	8.3%	5.9%	3.3%	7.1%	8.9%	9.4%	8.8%	8.7%	10.9%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.0%*
.7%	8.3%	5.9%	3.3%	7.1%	8.9%	9.4%	8.8%	8.7%	10.9%	*9.5%*	*9.5%*	Return on Com Equity [E]	*10.0%*
NMF	3.2%	.7%	NMF	1.8%	3.7%	4.3%	3.8%	3.3%	5.3%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
NMF	62%	87%	NMF	75%	58%	54%	57%	62%	52%	*55%*	*57%*	All Div'ds to Net Prof	*60%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $3326.4 mill. **Due in 5 Yrs** $987.0 mill.
LT Debt $3109.4 mill. **LT Interest** $127.1 mill.
(LT interest earned: 3.2x)
Leases, Uncapitalized Annual rentals $5.0 mill.

Pension Assets-12/17 $416.3 mill.
Oblig $474.7 mill.

Pfd Stock None

Common Stock 53,544,761 shs.
as of 1/31/18

MARKET CAP: $2.9 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+4.5	+3.0	+.9
Avg. Indust. Use (MWH)	15552	17321	18376
Avg. Indust. Revs. per KWH (¢)	8.02	7.80	7.69
Capacity at Yearend (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	1028	1086	1094
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+.6	+.8
Fixed Charge Cov. (%)	324	236	296

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	1.0%	-.5%	*2.0%*
"Cash Flow"	2.5%	5.5%	*5.0%*
Earnings	2.5%	14.0%	*5.0%*
Dividends	2.5%	3.0%	*6.0%*
Book Value	2.5%	1.5%	*5.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	442.0	272.2	272.1	318.3	1304.6
2016	450.0	325.4	333.8	463.8	1573.0
2017	547.5	341.9	335.6	455.3	1680.3
2018	*530*	*335*	*335*	*450*	*1650*
2019	*545*	*345*	*345*	*465*	*1700*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.07	.55	.58	.63	2.83
2016	.94	.31	.41	.97	2.63
2017	1.42	.41	.52	1.03	3.38
2018	*1.40*	*.40*	*.60*	*1.05*	*3.45*
2019	*1.45*	*.40*	*.60*	*1.10*	*3.55*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.39	.39	.39	.39	1.56
2015	.405	.405	.405	.405	1.62
2016	.42	.42	.42	.42	1.68
2017	.445	.445	.445	.475	1.81
2018	.475				

BUSINESS: Black Hills Corporation is a holding company for Black Hills Energy, which serves 209,000 electric customers in CO, SD, WY and MT, and 1 million gas customers in NE, IA, KS, CO, WY, and AR. Has coal mining sub. Acq'd Cheyenne Light 1/05; utility ops. from Aquila 7/08; SourceGas 2/16. Discont. telecom in '05; oil marketing in '06; gas marketing in '11; gas & oil E&P in '17. Electric rev. breakdown: res'l, 30%; comm'l, 37%; ind'l, 17%; other, 16%. Generating sources: coal, 32%; other, 8%; purch., 60%. Fuel costs: 34% of revs. '17 depr. rate: 3.5%. Has 2,700 employees. Chairman & CEO: David R. Emery. Pres. & COO: Linn Evans. Inc.: SD. Address: 7001 Mount Rushmore Rd., P.O. Box 1400, Rapid City, SD 57709-1400. Tel.: 605-721-1700. Internet: www.blackhillscorp.com.

Black Hills Corporation has discontinued its gas and oil exploration and production operation. This segment was once profitable, but fell into the red after commodity prices weakened a few years ago. Black Hills has sold or executed agreements to sell almost all of these assets, raising some $75 million in the process. Management expects to complete this process by midyear. The company retains some nonutility businesses, but is predominantly a regulated electric and gas utility. Black Hills posted a loss of $0.31 a share from discontinued operations last year, and additional deficits are possible in 2018.

The company's gas utility in Arkansas has a rate case pending, and other filings are upcoming. Black Hills filed for a tariff hike of $29.9 million, based on a return of 10.2% on a common-equity ratio of 54.7%. New tariffs are expected to take effect in the fourth quarter. Small gas requests (totaling about $3 million) are pending in Colorado and Wyoming, as well. These are the first three of 10 rate applications that Black Hills plans to put forth over a four-year period.

A legal appeal of a rate order in Colorado is pending. In December of 2016, the state commission granted Black Hills just $1.2 million of the $8.9 million electric rate hike the utility had sought. The regulators rejected the company's request for a rehearing, reargument, or reconsideration, so Black Hills took this matter to the courts.

We have trimmed our 2018 earnings estimate by $0.05 a share, to $3.45. This is in accordance with the company's reduction in its 2018 earnings guidance, from a range of $3.35-$3.55 to $3.30-$3.50. Interest expense is likely to be greater than previously expected due to rising short-term interest rates.

We forecast modest profit growth in 2019. Rate relief from the aforementioned rate cases should help. Our estimate of $3.55 a share would produce a 3% earnings increase.

Black Hills shares have a dividend yield that is average for a utility. Good dividend growth over the 3- to 5-year period should produce total returns that are better than those of most utility issues.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. nonrec. gains (losses): '08, ($1.55); '09, (28¢); '10, 10¢; '12, 4¢; '15, ($3.54); '16, ($1.26); '17, 14¢; gains (losses) on disc. ops.: '06, 21¢; '07, (4¢); '08, $4.12; '09, 7¢; '11, 23¢; '12, (16¢); '17, (31¢). Next earnings report due early May. **(B)** Div'ds paid early Mar., Jun., Sept., & Dec. ■ Div'd reinvestment plan avail. **(C)** Incl. def'd chgs. In '17: $28.45/sh. **(D)** In mill. **(E)** Rate base: Net orig. cost. Rate all'd on com. eq. in SD in '15: none specified; in CO in '17: 9.37%; earned on avg. com. eq., '17: 10.8%. Regulatory Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	75
Price Growth Persistence	65
Earnings Predictability	50

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CMS ENERGY CORP. NYSE-CMS

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
42.69	18.0 (Trailing: 19.7 Median: 16.0)	0.94	3.4%	

TIMELINESS 2 Raised 2/23/18
SAFETY 2 Raised 3/21/14
TECHNICAL 3 Lowered 2/23/18
BETA .65 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+15%)	7%
Low	35	(-20%)	-1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	11	0	0	0	0	0	0	0	11
to Sell	5	0	0	3	0	0	2	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	242	210	223
to Sell	217	225	170
Hld's(000)	273775	282715	254375

	High:	19.5	17.5	16.1	19.3	22.4	25.0	30.0	36.9	38.7	46.3	50.8	47.4
	Low:	15.0	8.3	10.0	14.1	17.0	21.1	24.6	26.0	31.2	35.0	41.1	40.5

LEGENDS
0.83 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2021 | 2022 | 2023

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.8	10.1
3 yr.	32.6	24.2
5 yr.	87.8	76.2

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
60.28	34.21	28.06	28.52	30.57	28.95	30.13	27.23	25.77	25.59	23.90	24.68	26.09	23.29	22.92	23.37	*23.40*	*24.10*	Revenues per sh	*26.00*
d.09	2.39	2.87	3.43	3.22	3.08	3.88	3.47	3.70	3.65	3.82	4.06	4.22	4.59	4.88	5.29	*5.65*	*5.95*	"Cash Flow" per sh	*7.00*
d2.99	d.29	.74	1.10	.64	.64	1.23	.93	1.33	1.45	1.53	1.66	1.74	1.89	1.98	2.17	*2.35*	*2.50*	Earnings per sh [A]	*3.00*
1.09	- -	- -	- -	- -	.20	.36	.50	.66	.84	.96	1.02	1.08	1.16	1.24	1.33	*1.43*	*1.53*	Div'd Decl'd per sh [B] ■	*1.85*
5.18	3.32	2.69	2.69	3.01	5.61	3.50	3.59	3.29	3.47	4.65	4.98	5.73	5.64	5.99	5.91	*7.40*	*8.40*	Cap'l Spending per sh	*6.50*
7.86	9.84	10.63	10.53	10.03	9.46	10.88	11.42	11.19	11.92	12.09	12.98	13.34	14.21	15.23	15.77	*16.95*	*18.20*	Book Value per sh [C]	*22.25*
144.10	161.13	195.00	220.50	222.78	225.15	226.41	227.89	249.60	254.10	264.10	266.10	275.20	277.16	279.21	281.65	*284.00*	*286.50*	Common Shs Outst'g [D]	*294.00*
- -	- -	12.4	12.6	22.2	26.8	10.9	13.6	12.5	13.6	15.1	16.3	17.3	18.3	20.9	21.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*14.5*
- -	- -	.66	.67	1.20	1.42	.66	.91	.80	.85	.96	.92	.91	.92	1.10	1.06			Relative P/E Ratio	*.80*
7.5%	- -	- -	- -	- -	1.2%	2.7%	4.0%	4.0%	4.3%	4.2%	3.8%	3.6%	3.4%	3.0%	2.9%			Avg Ann'l Div'd Yield	*4.2%*
6821.0	6205.0	6432.0	6503.0	6312.0	6566.0	7179.0	6456.0	6399.0	6583.0	*6650*	*6900*	Revenues ($mill)	*7650*
300.0	231.0	356.0	384.0	413.0	454.0	479.0	525.0	553.0	610.0	*670*	*725*	Net Profit ($mill)	*900*
31.6%	34.6%	38.1%	36.8%	39.4%	39.9%	34.3%	34.0%	33.1%	31.2%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
1.3%	13.0%	2.2%	2.6%	2.9%	2.0%	2.3%	2.7%	3.1%	1.1%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
69.4%	67.9%	70.1%	66.9%	67.9%	67.5%	68.7%	68.3%	67.1%	67.3%	*64.5%*	*63.5%*	Long-Term Debt Ratio	*62.0%*
27.4%	29.0%	29.5%	32.6%	31.6%	32.2%	31.0%	31.4%	32.6%	32.4%	*35.5%*	*36.0%*	Common Equity Ratio	*37.5%*
8993.0	8977.0	9473.0	9279.0	10101	10730	11846	12534	13040	13692	*13625*	*14475*	Total Capital ($mill)	*17500*
9190.0	9682.0	10069	10633	11551	12246	13412	14705	15715	16761	*17925*	*19350*	Net Plant ($mill)	*22100*
5.4%	4.7%	5.8%	6.3%	5.9%	6.0%	5.7%	5.7%	5.8%	5.9%	*6.5%*	*6.5%*	Return on Total Cap'l	*6.5%*
10.9%	8.0%	12.5%	12.5%	12.8%	13.0%	12.9%	13.2%	12.9%	13.6%	*14.0%*	*14.0%*	Return on Shr. Equity	*13.5%*
11.7%	8.5%	12.5%	12.6%	12.9%	13.1%	13.0%	13.3%	13.0%	13.7%	*14.0%*	*14.0%*	Return on Com Equity [E]	*13.5%*
8.4%	4.1%	6.9%	5.6%	5.0%	5.2%	5.0%	5.2%	4.8%	5.2%	*5.5%*	*5.5%*	Retained to Com Eq	*5.5%*
31%	54%	46%	55%	61%	60%	62%	61%	63%	62%	*61%*	*60%*	All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $10487 mill. **Due in 5 Yrs** $4879 mill.
LT Debt $9214 mill. **LT Interest** $405 mill.
Incl. $91 mill. capitalized leases.
(LT interest earned: 3.2x)
Leases, Uncapitalized Annual rentals $15 mill.
Pension Assets-12/17 $2305 mill.
Oblig $2780 mill.
Pfd Stock $37 mill. **Pfd Div'd** $2 mill.
Incl. 373,148 shs. $4.50 $100 par, cum., callable at $110.00.
Common Stock 282,420,406 shs.
as of 1/31/18
MARKET CAP: $12 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.8	+1.7	-1.4
Avg. Indust. Use (MWH)	5922	6031	NA
Avg. Indust. Revs. per KWH (¢)	8.07	7.76	NA
Capacity at Peak (Mw)	8762	8331	NA
Peak Load, Summer (Mw)	7812	8227	7634
Annual Load Factor (%)	55.5	54.6	NA
% Change Customers (yr-end)	+.6	+.5	+1.2
Fixed Charge Cov. (%)	288	292	301

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-2.5%	-1.5%	*2.0%*
"Cash Flow"	4.0%	5.5%	*6.5%*
Earnings	10.0%	7.0%	*8.5%*
Dividends	- -	8.5%	*7.0%*
Book Value	4.0%	5.0%	*6.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	2111	1350	1486	1509	6456.0
2016	1801	1371	1587	1640	6399.0
2017	1829	1449	1527	1778	6583.0
2018	*1850*	*1450*	*1550*	*1800*	*6650*
2019	*1900*	*1550*	*1600*	*1850*	*6900*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.73	.25	.53	.38	1.89
2016	.59	.45	.67	.28	1.98
2017	.71	.33	.61	.52	2.17
2018	*.80*	*.40*	*.65*	*.50*	*2.35*
2019	*.85*	*.45*	*.70*	*.50*	*2.50*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec. 31	Full Year
2014	.27	.27	.27	.27	1.08
2015	.29	.29	.29	.29	1.16
2016	.31	.31	.31	.31	1.24
2017	.3325	.3325	.3325	.3325	1.33
2018	.3575				

BUSINESS: CMS Energy Corporation is a holding company for Consumers Energy, which supplies electricity and gas to lower Michigan (excluding Detroit). Has 1.8 million electric, 1.8 million gas customers. Has 1,034 megawatts of nonregulated generating capacity. Sold Palisades nuclear plant in '07. Electric revenue breakdown: residential, 43%; commercial, 34%; industrial, 17%; other, 6%. Generating sources: coal, 28%; gas, 15%; other, 2%; purchased, 55%. Fuel costs: 43% of revenues. '17 reported deprec. rates: 3.9% electric, 2.9% gas, 10.0% other. Has 7,900 employees. Chairman: John G. Russell. President & CEO: Patricia K. Poppe. Incorporated: Michigan. Address: One Energy Plaza, Jackson, MI 49201. Tel.: 517-788-0550. Internet: www.cmsenergy.com.

CMS Energy's utility subsidiary should soon get an order in its electric rate case. Consumers Energy is seeking an increase of $173 million, based on a 10.5% return on equity. The utility self-implemented an increase of $130 million on October 1st. The staff of the Michigan Public Service Commission (MPSC) recommended an increase of $65 million, based on a 9.8% ROE, and an administrative law judge proposed a hike of $30 million, based on a 9.8% ROE. A decision from the MPSC is due by the end of the month.

Consumers Energy also has a gas rate pending. The utility filed for a hike of $178 million, based on a 10.5% ROE. Consumers also requested a regulatory mechanism that would allow concurrent recovery of certain capital expenditures, along with the decoupling of gas volume and revenues. A decision is due by the end of August.

We expect a solid bottom-line showing in 2018. Rate relief should help. A return to normal weather patterns would be positive for the utility. Management is controlling expenses effectively, too. Our estimate of $2.35 a share is slightly above the company's typically narrow guidance of $2.30-$2.34.

We forecast profit growth next year in line with CMS' annual target of 6%-8%. Again, rate relief and effective cost control ought to be key factors. A bit of kilowatt-hour sales growth should help, too.

The board of directors raised the dividend in the current quarter. The increase was $0.10 a share (7.5%) annually. We project dividend growth in a range of 6%-8% a year over the 3- to 5-year period. This is the same as CMS' target for profit growth.

Tax reform caused a nonrecurring charge of $0.53 a share in the fourth quarter of 2017. The new tax law will also make cash flow lower than it otherwise would have been in the near term.

This timely equity's dividend yield is only about average for a utility. Like many utility issues, the recent price is well within our 2021-2023 Target Price Range. Thus, total return potential over that time frame is unimpressive.

Paul E. Debbas, CFA *March 16, 2018*

(A) Diluted EPS. Excl. nonrec. gains (losses): '05, ($1.61); '06, ($1.08); '07, ($1.26); '09, (7¢); '10, 3¢; '11, 12¢; '12, (14¢); '17, (53¢); gains (losses) on disc. ops.: '05, 7¢; '06, 3¢; '07, (40¢); '09, 8¢; '10, (8¢); '11, 1¢; '12, 3¢. '16 EPS don't sum due to rounding. Next earnings report due late Apr. **(B)** Div'ds historically paid late Feb., May, Aug., & Nov. ■ Div'd reinvest. plan avail. **(C)** Incl. intang. In '17: $6.26/sh. **(D)** In mill. **(E)** Rate base: Net orig. cost. Rate allowed on com. eq. in '17: 10.1%; earned on avg. com. eq., '17: 10.6%. Regul. Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	90

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CENTERPOINT EN'RGY NYSE-CNP

RECENT PRICE **26.77** | P/E RATIO **16.0** (Trailing: 17.1 Median: 15.0) | RELATIVE P/E RATIO **0.84** | DIV'D YLD **4.2%** | **VALUE LINE**

TIMELINESS **3** Lowered 3/2/18
SAFETY **3** Lowered 12/18/15
TECHNICAL **3** Lowered 2/16/18
BETA .85 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+10%)	7%
Low	20	(-25%)	-2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	8	0	0	0	0	0	0	0	0
to Sell	1	1	1	1	1	1	1	1	1

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	251	241	208
to Sell	236	236	200
Hld's(000)	371022	375340	332194

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	20.2	17.3	14.9	17.0	21.5	21.8	25.7	25.8	23.7	25.0	30.5	28.5						
Low:	14.7	8.5	8.7	5.5	15.1	18.1	19.3	21.1	16.0	16.4	24.5	25.8						

LEGENDS
0.63 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2021 | 2022 | 2023

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.9	10.1
3 yr.	49.2	24.2
5 yr.	56.2	76.2

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
	26.40	31.87	27.63	31.33	29.71	29.82	32.71	21.14	20.69	19.83	17.43	18.90	21.51	17.18	17.48	22.30	***22.30***	***24.00***	Revenues per sh	***27.50***
	3.34	3.98	2.56	2.72	3.47	3.39	3.42	2.94	3.14	3.43	3.89	3.54	3.85	3.40	3.68	4.03	***4.10***	***4.35***	"Cash Flow" per sh	***5.00***
	1.29	1.37	.61	.67	1.33	1.17	1.30	1.01	1.07	1.27	1.35	1.24	1.42	1.08	1.00	1.57	***1.55***	***1.65***	Earnings per sh [A]	***2.00***
	1.07	.40	.40	.40	.60	.68	.73	.76	.78	.79	.81	.83	.95	.99	1.03	1.35	***1.11***	***1.15***	Div'd Decl'd per sh [B] ■	***1.27***
	2.85	2.11	1.72	2.23	3.21	3.45	2.95	2.96	3.55	3.06	2.84	3.00	3.20	3.68	3.28	3.31	***3.85***	***3.75***	Cap'l Spending per sh	***3.75***
	4.74	5.75	3.59	4.18	4.96	5.61	5.89	6.74	7.53	9.91	10.06	10.09	10.60	8.05	8.03	10.88	***11.35***	***11.85***	Book Value per sh [C]	***14.00***
	300.10	306.30	308.05	310.33	313.65	322.72	346.09	391.75	424.70	426.03	427.44	429.00	429.00	430.00	430.68	431.04	***431.00***	***431.00***	Common Shs Outst'g [D]	***435.00***
	5.6	6.0	17.8	19.1	10.3	15.0	11.3	11.8	13.8	14.6	14.8	18.7	17.0	18.1	21.9	17.9			Avg Ann'l P/E Ratio	***13.5***
	.31	.34	.94	1.02	.56	.80	.68	.79	.88	.92	.94	1.05	.89	.91	1.15	.89			Relative P/E Ratio	***.75***
	14.8%	4.8%	3.7%	3.1%	4.4%	3.9%	5.0%	6.4%	5.3%	4.3%	4.0%	3.6%	3.9%	5.1%	4.7%	4.8%			Avg Ann'l Div'd Yield	***4.7%***
	11322	8281.0	8785.0	8450.0	7452.0	8106.0	9226.0	7386.0	7528.0	9614.0	***9850***	***10350***	Revenues ($mill)	***12000***
	447.0	372.0	442.0	546.0	581.0	536.0	611.0	465.0	432.0	679.0	***675***	***725***	Net Profit ($mill)	***865***
	38.3%	32.1%	37.3%	33.6%	33.4%	31.4%	31.0%	35.1%	37.0%	36.1%	***21.0%***	***21.0%***	Income Tax Rate	***21.0%***
	2.7%	1.3%	2.7%	1.6%	2.6%	3.5%	4.1%	4.7%	3.5%	2.9%	***3.0%***	***3.0%***	AFUDC % to Net Profit	***2.0%***
	83.3%	77.6%	73.8%	67.2%	66.0%	64.4%	63.8%	69.5%	68.5%	63.6%	***63.0%***	***62.5%***	Long-Term Debt Ratio	***60.5%***
	16.7%	22.4%	26.2%	32.8%	34.0%	35.6%	36.2%	30.5%	31.5%	36.4%	***37.0%***	***37.5%***	Common Equity Ratio	***39.5%***
	12218	11758	12199	12863	12658	12146	12557	11362	10992	12883	***13175***	***13550***	Total Capital ($mill)	***15300***
	10296	10788	11732	12402	13597	9593.0	10502	11537	12307	13057	***13875***	***14600***	Net Plant ($mill)	***16600***
	6.0%	5.8%	6.1%	6.4%	6.8%	6.3%	6.7%	6.1%	5.8%	6.8%	***6.5%***	***7.0%***	Return on Total Cap'l	***7.0%***
	21.9%	14.1%	13.8%	12.9%	13.5%	12.4%	13.4%	13.4%	12.5%	14.5%	***14.0%***	***14.0%***	Return on Shr. Equity	***14.5%***
	21.9%	14.1%	13.8%	12.9%	13.5%	12.4%	13.4%	13.4%	12.5%	14.5%	***14.0%***	***14.0%***	Return on Com Equity [E]	***14.5%***
	9.9%	3.6%	3.8%	5.0%	5.5%	4.2%	4.5%	1.1%	NMF	4.7%	***4.0%***	***4.5%***	Retained to Com Eq	***5.0%***
	55%	74%	72%	62%	60%	66%	67%	92%	NMF	68%	***71%***	***69%***	All Div'ds to Net Prof	***64%***

Bold figures are Value Line estimates

CAPITAL STRUCTURE as of 12/31/17
Total Debt $8840 mill. **Due in 5 Yrs** $5313 mill.
LT Debt $8195 mill. **LT Interest** $402 mill.
Incl. $1500 mill. securitized transition & system restoration bonds.
(LT interest earned: 3.7x)
Leases, Uncapitalized Annual rentals $5 mill.
Pension Assets-12/17 $1801 mill.
Oblig $2225 mill.

Pfd Stock None
Common Stock 431,048,125 shs.
as of 2/9/18
MARKET CAP: $12 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+2.9	+3.1	+2.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+2.1	+2.3	+1.7
Fixed Charge Cov. (%)	200	219	269

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-4.5%	-.5%	*6.5%*
"Cash Flow"	1.5%	1.0%	*1.5%*
Earnings	1.5%	- -	*-.5%*
Dividends	7.0%	7.0%	*2.0%*
Book Value	6.0%	-.5%	*7.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2015	2433	1532	1630	1791	7386.0
2016	1984	1574	1889	2081	7528.0
2017	2735	2143	2098	2638	9614.0
2018	***2800***	***2200***	***2150***	***2700***	***9850***
2019	***2950***	***2300***	***2250***	***2850***	***10350***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2015	.30	.18	.34	.26	1.08
2016	.36	d.01	.41	.25	1.00
2017	.44	.31	.39	.43	1.57
2018	***.44***	***.33***	***.47***	***.31***	***1.55***
2019	***.47***	***.35***	***.50***	***.33***	***1.65***

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.2375	.2375	.2375	.2375	.95
2015	.2475	.2475	.2475	.2475	.99
2016	.2575	.2575	.2575	.2575	1.03
2017	.2675	.2675	.2675	.2675	1.07
2018	.2775				

BUSINESS: CenterPoint Energy, Inc. is a holding company for Houston Electric, which serves 2.4 million customers in Houston and environs, and gas utilities with 3.4 million customers in Texas, Minnesota, Arkansas, Louisiana, and Oklahoma. Owns 54.1% of Enable Midstream Partners. Discontinued Texas Genco Holdings in '04. Electric revenue breakdown: residential, 52%; commercial, 31%; industrial, 15%; other, 2%. Does not own generating assets. Gas costs: 51% of revenues. '17 depreciation rate: 5.6%. Has 8,000 employees. Chairman: Milton Carroll. President & CEO: Scott M. Prochazka. Incorporated: Texas. Address: 1111 Louisiana, P.O. Box 4567, Houston, Texas 77210-4567. Telephone: 713-207-1111. Internet: www.centerpointenergy.com.

CenterPoint Energy wants to reduce its exposure to commodity prices, which stems from its ownership interest in Enable Midstream Partners. The goal is to sell its stake gradually over a multiyear period. Because the amount and timing of any sales cannot be predicted, our estimates and projections are based on CenterPoint's current 54.1% interest in the master limited partnership.

Tax reform is helping CenterPoint's earnings. The revaluation of deferred taxes, which was necessitated by the new federal tax law, added $2.56 a share to earnings in the fourth quarter of 2017. This was a noncash, nonrecurring item, but boosted the company's common-equity ratio. In 2018, the reduced federal tax rate should boost the bottom line by $0.10 a share thanks to the positive effect on CenterPoint's equity income from its stake in Enable. Finally, the company's forecasted rate base at yearend will be $300 million greater because deferred taxes (which offset rate base) will be lower. This will raise CenterPoint's earning power.

We forecast 6% profit growth in 2019. This is within CenterPoint's annual earnings growth goal of 5%-7%. We think the company will benefit from rate relief, increased electric deliveries, greater income from its interest in Enable, and a rise in profits as the company's energy services subsidiary grows. Note, though, that the energy services unit books mark-to-market gains or charges, which we *include* in our earnings presentation, so this adds an element of unpredictability to our estimates.

The board of directors raised the dividend. This move is usually made in early January every year, but the declaration was moved up to December of 2017. Thus, five dividends were declared last year, which is why the statistical array above shows a sharp rise in dividends declared in 2017. The quarterly increase was a cent a share (3.7%), the same hike as in each of the previous three years.

The dividend yield of CenterPoint stock is above the utility average. However, with the recent price above the midpoint of our 2021-2023 Target Price Range, the modest dividend growth we project over that period is unlikely to produce an above-average total return.

Paul E. Debbas, CFA *March 16, 2018*

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	70

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(A) Diluted EPS. Excl. extraordinary gains (losses): '04, ($2.72); '05, 9¢; '11, $1.89; '12, (38¢) net; '13, (52¢); '15, ($2.69); '17, $2.56; losses on disc. ops.: '04, 37¢; '05, 1¢. '16 EPS don't sum due to rounding. Next earnings report due early May. **(B)** Div'ds historically paid in early Mar., June, Sept. & Dec. 5 declarations in '17. ■ Div'd reinv. plan avail. **(C)** Incl. intang. In '17: $7.46/sh. **(D)** In mill. **(E)** Rate base: Net orig. cost. Rate all'd on com. eq. (elec.) in '11: 10%; (gas): 9.45%-11.25%; earned on avg. com. eq., '17: NMF. Regulatory Climate: Avg.

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CON. EDISON NYSE-ED

RECENT PRICE **76.23** | P/E RATIO **17.9** (Trailing: 18.2 Median: 15.0) | RELATIVE P/E RATIO **1.01** | DIV'D YLD **3.8%** | **VALUE LINE**

TIMELINESS **3** Raised 3/2/18
SAFETY **1** New 7/27/90
TECHNICAL **4** Raised 5/18/18
BETA .50 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+10%)	7%
Low	70	(-10%)	2%

Insider Decisions

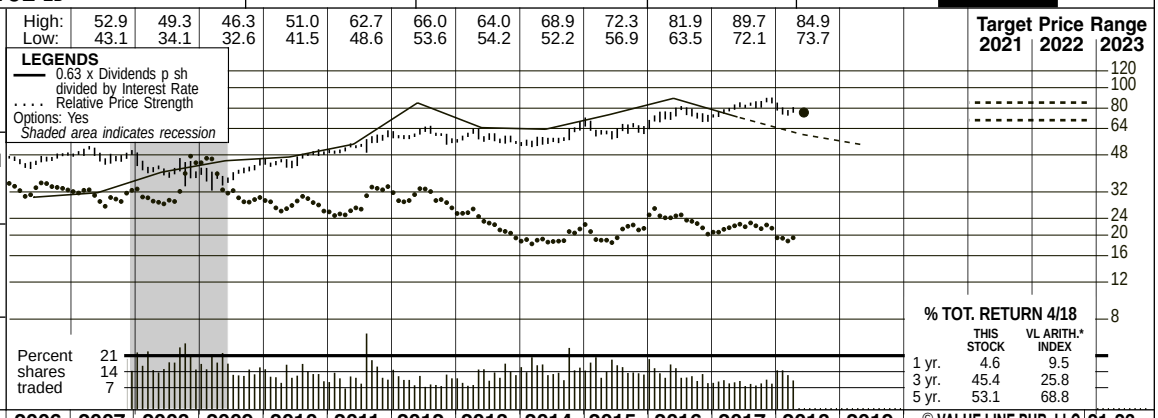
	J	A	S	O	N	D	J	F	M
to Buy	11	8	8	11	8	8	11	8	8
Options	0	0	0	2	2	0	8	12	0
to Sell	0	1	0	0	0	0	0	0	1

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	330	335	298
to Sell	323	322	284
Hld's(000)	196270	197384	178532

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
High:	52.9	49.3	46.3	51.0	62.7	66.0	64.0	68.9	72.3	81.9	89.7	84.9								
Low:	43.1	34.1	32.6	41.5	48.6	53.6	54.2	52.2	56.9	63.5	72.1	73.7								
	39.65	43.51	40.24	47.66	47.14	48.23	49.62	46.36	45.69	44.17	41.62	42.27	44.11	42.85	39.59	38.82	***38.80***	***39.80***	Revenues per sh	***43.25***
	5.44	5.12	4.54	5.27	5.28	5.77	5.99	5.86	6.24	6.61	7.15	7.45	7.30	7.93	7.89	8.41	***8.75***	***9.15***	"Cash Flow" per sh	***10.50***
	3.13	2.83	2.32	2.99	2.95	3.48	3.36	3.14	3.47	3.57	3.86	3.93	3.62	4.05	3.94	4.10	***4.25***	***4.40***	Earnings per sh [A]	***4.75***
	2.22	2.24	2.26	2.28	2.30	2.32	2.34	2.36	2.38	2.40	2.42	2.46	2.52	2.60	2.68	2.76	***2.86***	***2.96***	Div'd Decl'd per sh [B] ■	***3.30***
	5.68	5.72	5.60	6.59	7.17	7.09	8.50	7.80	6.96	6.72	7.06	8.67	8.26	10.42	12.07	11.11	***12.50***	***11.15***	Cap'l Spending per sh	***11.25***
	27.68	28.44	29.09	29.80	31.09	32.58	35.43	36.46	37.93	39.05	40.53	41.81	42.94	44.55	46.88	49.74	***51.70***	***53.25***	Book Value per sh [C]	***58.00***
	213.93	225.84	242.51	245.29	257.46	272.02	273.72	281.12	291.62	292.89	292.87	292.87	292.88	293.00	305.00	310.00	***317.00***	***318.00***	Common Shs Outst'g [D]	***321.00***
	13.3	14.3	18.2	15.1	15.5	13.8	12.3	12.5	13.3	15.1	15.4	14.7	15.9	15.6	18.8	19.8			Avg Ann'l P/E Ratio	***16.5***
	.73	.82	.96	.80	.84	.73	.74	.83	.85	.95	.98	.83	.84	.79	.99	.99			Relative P/E Ratio	***.90***
	5.3%	5.5%	5.3%	5.0%	5.0%	4.8%	5.7%	6.0%	5.2%	4.5%	4.1%	4.3%	4.4%	4.1%	3.6%	3.4%			Avg Ann'l Div'd Yield	***4.2%***
	13583	13032	13325	12938	12188	12381	12919	12554	12075	12033	***12300***	***12650***	Revenues ($mill)	***13850***
	933.0	868.0	992.0	1062.0	1141.0	1157.0	1066.0	1193.0	1189.0	1266.0	***1340***	***1405***	Net Profit ($mill)	***1550***
	36.0%	34.2%	36.0%	36.1%	34.5%	31.8%	34.0%	33.6%	35.3%	36.6%	***21.5%***	***21.5%***	Income Tax Rate	***21.5%***
	1.7%	2.6%	2.4%	1.6%	.5%	.5%	.3%	.7%	1.3%	1.5%	***2.0%***	***1.0%***	AFUDC % to Net Profit	***1.0%***
	48.3%	48.5%	48.6%	46.5%	45.9%	46.1%	48.0%	47.9%	50.8%	48.9%	***49.0%***	***48.5%***	Long-Term Debt Ratio	***48.5%***
	50.6%	50.4%	50.4%	52.5%	54.1%	53.9%	52.0%	52.1%	49.2%	51.1%	***51.0%***	***51.5%***	Common Equity Ratio	***51.5%***
	19160	20330	21952	21794	21933	22735	24207	25058	29033	30149	***32150***	***32900***	Total Capital ($mill)	***36200***
	20874	22464	23863	25093	26939	28436	29827	32209	35216	37600	***40150***	***42075***	Net Plant ($mill)	***47800***
	6.2%	5.7%	5.9%	6.2%	6.5%	6.4%	5.6%	6.0%	5.3%	5.4%	***5.5%***	***5.5%***	Return on Total Cap'l	***5.5%***
	9.4%	8.3%	8.8%	9.1%	9.6%	9.4%	8.5%	9.1%	8.3%	8.2%	***8.0%***	***8.5%***	Return on Shr. Equity	***8.5%***
	9.5%	8.4%	8.9%	9.2%	9.6%	9.4%	8.5%	9.1%	8.3%	8.2%	***8.0%***	***8.5%***	Return on Com Equity [E]	***8.5%***
	3.1%	2.5%	3.2%	3.1%	3.6%	3.6%	2.6%	3.5%	3.0%	3.0%	***2.5%***	***2.5%***	Retained to Com Eq	***2.5%***
	67%	71%	65%	66%	62%	62%	69%	61%	64%	63%	***67%***	***67%***	All Div'ds to Net Prof	***68%***

Bold figures are Value Line estimates



CAPITAL STRUCTURE as of 3/31/18
Total Debt $17410 mill. **Due in 5 Yrs** $4935 mill.
LT Debt $14730 mill. **LT Interest** $670 mill.
(LT interest earned: 3.6x)

Leases, Uncapitalized Annual rentals $63 mill.

Pension Assets-12/17 $14274 mill.
Oblig $15536 mill.

Pfd Stock None

Common Stock 310,730,465 shs.
as of 4/30/18
MARKET CAP: $24 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+1.9	-.4	-2.8
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NMF	NA	NA
Peak Load, Summer (Mw)	13721	NA	NA
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	370	352	354

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-1.5%	-1.5%	*1.0%*
"Cash Flow"	4.0%	4.0%	*4.5%*
Earnings	2.5%	2.0%	*3.0%*
Dividends	1.5%	2.0%	*3.5%*
Book Value	4.0%	3.5%	*3.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	3616	2788	3443	2707	12554
2016	3157	2794	3417	2707	12075
2017	3228	2633	3211	2961	12033
2018	3364	***2750***	***3436***	***2750***	***12300***
2019	***3450***	***2850***	***3500***	***2850***	***12650***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.26	.74	1.45	.60	4.05
2016	1.05	.77	1.47	.64	3.94
2017	1.27	.57	1.48	.78	4.10
2018	1.37	***.63***	***1.60***	***.65***	***4.25***
2019	***1.40***	***.65***	***1.65***	***.70***	***4.40***

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.63	.63	.63	.63	2.52
2015	.65	.65	.65	.65	2.60
2016	.67	.67	.67	.67	2.68
2017	.69	.69	.69	.69	2.76
2018	.715				

BUSINESS: Consolidated Edison, Inc. is a holding company for Consolidated Edison Company of New York, Inc. (CECONY), which sells electricity, gas, and steam in most of New York City and Westchester County. Also owns Orange and Rockland Utilities (O&R), which operates in New York and New Jersey. Has 3.7 million electric, 1.2 million gas customers. Pursues competitive energy opportunities through three wholly owned subsidiaries. Entered into midstream gas joint venture 6/16. Purchases most of its power. Fuel costs: 22% of revenues. '17 reported depreciation rates: 2.9%-3.1%. Has 15,000 employees. Chairman, President & CEO: John McAvoy. Inc.: New York. Address: 4 Irving Place, New York, New York 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

We estimate that Consolidated Edison's earnings will rise 3%-4% this year and next. ConEd's largest subsidiary, Consolidated Edison Company of New York, is benefiting from rate relief. At the start of 2018, electric and gas tariffs were boosted by $155.3 million (2.0%) and $92.3 million (5.6%), respectively. Increases of $155.2 million (1.9%) for electricity and $89.4 million (5.1%) for gas will take effect at the beginning of 2019. Orange and Rockland Utilities might also obtain a rate increase next year (see below). Customer growth is another plus. And oil-heating users continue to convert to the use of gas heat. Our 2018 earnings estimate, which we raised by a nickel a share, is at the midpoint of the company's targeted range of $4.15-$4.35 a share. We lifted our 2019 estimate by $0.10 a share, to $4.40.

Orange and Rockland has a rate case pending. The utility is asking the New York State Public Service Commission for electric and gas increases of $22.5 million and $2.7 million, respectively, based on a return of 9.75% on a common-equity ratio of 48%. New rates should take effect at the start of 2019.

A natural gas pipeline project is under way, and another is being proposed. ConEd's 12.5% stake in the pipeline represents an investment of $400 million for the company. This is scheduled for completion by yearend. ConEd also has a 6.375% stake in a much-shorter pipeline proposal.

The company has some financing needs. The utilities plan to issue $1.3 billion-$1.8 billion of long-term debt this year. ConEd will issue up to $450 million of common equity, over and above what will be raised through the dividend reinvestment and other stock plans (perhaps $80 million).

ConEd's renewable-energy subsidiary continues to add projects. A 25-megawatt wind facility went into effect in the first quarter. The company has 1,561 mw of wind and solar projects in service or under construction.

High-quality ConEd stock has a dividend yield that is a bit above average for a utility. However, with the recent price well within our 2021-2023 Target Price Range, total return potential is low.

Paul E. Debbas, CFA *May 18, 2018*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, (11¢); '03, (45¢); '13, (32¢); '14, 9¢; '16, 15¢; '17, 84¢; gain on discontinued operations: '08, $1.01. '16 EPS don't sum due to rounding. Next earnings report due early Aug. **(B)** Div'ds historically paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. **(C)** Incl. intang. In '17: $16.04/sh. **(D)** In mill. **(E)** Rate base: net orig. cost. Rate allowed on com. eq. for CECONY in '17: 9.0%; O&R in '15: 9.0%; earned on avg. com. eq., '17: 8.6%. Regulatory Climate: Below Average.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	95

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DOMINION ENERGY NYSE-D

RECENT PRICE **63.14** | P/E RATIO **17.3** (Trailing: 19.2 Median: 19.0) | RELATIVE P/E RATIO **0.97** | DIV'D YLD **5.6%** | **VALUE LINE**

TIMELINESS **3** Raised 5/11/18
SAFETY **2** Raised 9/11/98
TECHNICAL **3** Raised 5/18/18
BETA .65 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	115	(+80%)	*20%*
Low	85	(+35%)	*13%*

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	1
Options	0	0	0	0	0	0	0	7	0
to Sell	0	0	0	0	1	0	0	1	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	463	472	471
to Sell	401	405	359
Hld's(000)	459958	461217	425609

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
High:	49.4	48.5	39.8	45.1	53.6	55.6	68.0	80.9	79.9	79.0	85.3	81.7								
Low:	39.8	31.3	27.1	36.1	42.1	48.9	51.9	63.1	64.5	66.3	70.9	63.0								
	16.58	18.57	20.54	25.96	23.61	27.17	27.93	25.24	26.17	25.24	22.73	22.56	21.25	19.59	18.70	19.53	***18.60***	***19.00***	Revenues per sh	***20.25***
	4.45	3.97	4.18	3.70	4.91	5.08	5.07	4.82	5.11	5.04	5.24	5.47	5.71	5.98	6.33	6.90	***7.15***	***8.05***	"Cash Flow" per sh	***9.50***
	2.41	1.96	2.13	1.50	2.40	2.13	3.04	2.64	2.89	2.76	2.75	3.09	3.05	3.20	3.44	3.53	***3.65***	***4.25***	Earnings per sh [A]	***5.00***
	1.29	1.29	1.30	1.34	1.38	1.46	1.58	1.75	1.83	1.97	2.11	2.25	2.40	2.59	2.80	3.04	***3.34***	***3.68***	Div'd Decl'd per sh [B] ■	***4.65***
	2.17	5.20	3.88	4.83	5.81	6.89	6.09	6.40	5.89	6.41	7.20	7.06	9.13	9.35	9.69	8.54	***7.35***	***6.95***	Cap'l Spending per sh	***7.50***
	16.57	16.20	16.79	14.96	18.50	16.31	17.28	18.66	20.66	20.09	18.34	20.02	19.74	21.24	23.26	26.59	***29.05***	***29.90***	Book Value per sh [C]	***32.00***
	616.20	650.40	680.40	695.00	698.00	576.80	583.20	599.40	580.80	569.70	576.10	581.50	585.30	596.30	627.80	644.60	***677.00***	***681.00***	Common Shs Outst'g [D]	***693.00***
	12.0	15.2	15.1	24.9	16.0	20.6	13.8	12.7	14.3	17.3	18.9	19.2	23.0	22.1	21.3	22.2			Avg Ann'l P/E Ratio	***20.0***
	.66	.87	.80	1.33	.86	1.09	.83	.85	.91	1.09	1.20	1.08	1.21	1.11	1.12	1.11			Relative P/E Ratio	***1.10***
	4.4%	4.3%	4.0%	3.6%	3.6%	3.3%	3.8%	5.2%	4.4%	4.1%	4.1%	3.8%	3.4%	3.7%	3.8%	3.9%			Avg Ann'l Div'd Yield	***4.7%***
	16290	15131	15197	14379	13093	13120	12436	11683	11737	12586	***12600***	***12950***	Revenues ($mill)	***14000***
	1781.0	1585.0	1724.0	1603.0	1594.0	1806.0	1793.0	1899.0	2123.0	2244.0	***2535***	***3035***	Net Profit ($mill)	***3630***
	37.1%	33.2%	38.6%	34.6%	36.2%	33.0%	28.1%	32.0%	22.8%	27.2%	***19.0%***	***19.0%***	Income Tax Rate	***19.0%***
	4.9%	4.8%	5.9%	5.3%	5.7%	3.7%	4.5%	5.3%	7.5%	10.5%	***5.0%***	***4.0%***	AFUDC % to Net Profit	***3.0%***
	59.1%	57.5%	56.3%	59.8%	60.9%	61.9%	65.4%	65.1%	67.4%	64.4%	***60.5%***	***62.0%***	Long-Term Debt Ratio	***61.5%***
	39.8%	41.5%	42.8%	39.3%	38.2%	37.3%	34.6%	34.9%	32.6%	35.6%	***39.5%***	***38.0%***	Common Equity Ratio	***38.5%***
	25290	26923	28012	29097	27676	31229	33360	36280	44836	48090	***49675***	***53350***	Total Capital ($mill)	***58000***
	23274	25592	26713	29670	30773	32628	36270	41554	49964	53758	***56300***	***58475***	Net Plant ($mill)	***65200***
	8.7%	7.5%	7.7%	7.0%	7.5%	7.3%	6.6%	6.5%	6.0%	5.9%	***6.5%***	***7.0%***	Return on Total Cap'l	***7.5%***
	17.2%	13.9%	14.1%	13.7%	14.7%	15.2%	15.5%	15.0%	14.5%	13.1%	***12.5%***	***14.5%***	Return on Shr. Equity	***16.0%***
	17.5%	14.0%	14.2%	13.9%	14.9%	15.4%	15.4%	15.0%	14.5%	13.1%	***12.5%***	***14.5%***	Return on Com Equity [E]	***16.0%***
	8.4%	4.7%	5.3%	4.0%	3.5%	4.2%	3.3%	2.9%	2.7%	1.8%	***1.0%***	***2.0%***	Retained to Com Eq	***1.5%***
	52%	67%	63%	71%	77%	73%	79%	81%	81%	86%	***87%***	***82%***	All Div'ds to Net Prof	***89%***

Bold figures are Value Line estimates

CAPITAL STRUCTURE as of 3/31/18
Total Debt $37436 mill. **Due in 5 Yrs** $15831 mill.
LT Debt $31120 mill. **LT Interest** $1235 mill.
(LT interest earned: 3.3x)

Leases, Uncapitalized Annual rentals $68 mill.

Pension Assets-12/17 $8062 mill.
Oblig $9052 mill.

Pfd Stock None

Common Stock 652,551,940 shs.
as of 4/13/18
MARKET CAP: $41 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+.7	NA	NA
Avg. Indust. Use (MWH)	13433	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.17	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	NA	NA
Fixed Charge Cov. (%)	352	310	287

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-3.0%	-5.0%	*1.0%*
"Cash Flow"	3.5%	4.5%	*7.0%*
Earnings	5.5%	4.0%	*6.5%*
Dividends	7.5%	7.5%	*9.0%*
Book Value	3.5%	4.0%	*5.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	3409	2747	2971	2556	11683
2016	2921	2598	3132	3086	11737
2017	3384	2813	3179	3210	12586
2018	3466	***2834***	***3200***	***3100***	***12600***
2019	***3550***	***2900***	***3300***	***3200***	***12950***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.91	.70	1.00	.60	3.20
2016	.88	.73	1.10	.73	3.44
2017	1.01	.62	1.03	.87	3.53
2018	.77	***.73***	***1.20***	***.95***	***3.65***
2019	***1.20***	***.75***	***1.30***	***1.00***	***4.25***

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.60	.60	.60	.60	2.40
2015	.6475	.6475	.6475	.6475	2.59
2016	.70	.70	.70	.70	2.80
2017	.755	.755	.755	.77	3.04
2018	.835				

LEGENDS
0.71 x Dividends p sh divided by Interest Rate
Relative Price Strength
2-for-1 split 11/07
Options: Yes
Shaded area indicates recession

Target Price Range 2021 | 2022 | 2023

% TOT. RETURN 4/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-10.6	9.5
3 yr.	4.3	25.8
5 yr.	30.2	68.8

BUSINESS: Dominion Energy, Inc. (formerly Dominion Resources) is a holding company for Virginia Power & North Carolina Power, which serve 2.6 mill. customers in VA & northeastern NC. Serves 2.3 mill. gas customers in OH, WV, & UT. Other ops. incl. independent power production. Owns 50.6% of Dominion Midstream Partners. Acq'd Questar 9/16. Elec. rev. breakdown: residential, 46%; commercial, 32%; industrial, 7%; other, 15%. Generating sources: nuclear, 32%; gas, 32%; coal, 17%; other, 5%; purch., 14%. Fuel costs: 24% of revs. '17 reported depr. rates: 2.2%-4.9%. Has 16,200 empls. Chairman, Pres. & CEO: Thomas F. Farrell II. Inc.: VA. Address: 120 Tredegar St., P.O. Box 26532, Richmond, VA 23261-6532. Tel.: 804-819-2000. Web: www.dominionenergy.com.

The stock of Dominion Energy has been the worst performer among electric utility issues so far in 2018. This year hasn't been good for equities in this industry, but Dominion Energy's price has plummeted 22%. The main reason was a Federal Energy Regulatory Commission ruling (in mid-March) about taxes that hurt gas pipeline master limited partnerships such as Dominion Midstream Partners, majority owned by Dominion Energy. Due to this ruling, Dominion Energy changed its plan to drop its Cove Point liquefied natural gas facility into its MLP affiliate this year.

The company is making some moves to strengthen its finances. Dominion Energy issued $500 million in common stock in the first quarter, and plans to sell another $1.5 billion over the remainder of 2018. The company has also cut a total of $1 billion from its capital budget for 2018 and 2019, and expanded its credit facilities. Finally, Dominion Energy is trying to sell some noncore assets, and would use the proceeds for debt reduction.

We have lowered our 2018 and 2019 earnings estimates. Virginia Power took a $215 million pretax charge in the first quarter (*included* in our earnings presentation) due to a new state law that will force the utility to give one-time rate credits to its customers. This is the main reason why we slashed our estimate by $0.45 a share, to $3.65. Another—and the explanation for our $0.15-a-share cut in 2019—is that average shares outstanding will be higher than we previously estimated.

Dominion Energy still hopes to acquire SCANA. The company would pay $6.0 billion in stock for the parent of South Carolina Electric & Gas, which canceled its nuclear construction project due to extensive delays and cost overruns. However, the proposal has received criticism in South Carolina, and Dominion will walk away if the regulators and/or legislature insist on concessions that would make the deal less attractive for the buyer.

This stock is appealing for income-oriented investors. The dividend yield is more than two percentage points above the mean for utilities, and healthy dividend growth potential to 2021-2023 should produce attractive long-term total returns.

Paul E. Debbas, CFA *May 18, 2018*

(A) Dil. egs. Excl. nonrec. gains (losses): '04, (22¢); '06, (18¢); '07, $1.67; '08, 12¢; '09, (47¢); '10, $2.18; '11, (7¢); '12, ($1.70); '14, (76¢); '17, $1.19 net; losses from disc. ops.: '06, 26¢; '07, 1¢; '10, 26¢; '12, 4¢; '13, 16¢. '15 EPS don't sum due to rounding. Next earnings report due late July. **(B)** Div'ds paid in mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. **(C)** Incl. intang. In '17: $14.85/sh. **(D)** In mill., adj. for split. **(E)** Rate base: Net orig. cost, adj. Rate all'd on com. eq. in '11: 10.9%; earn. on avg. com. eq., '17: 14.5%. Reg. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	90

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DTE ENERGY CO. NYSE-DTE

RECENT PRICE **101.20** | P/E RATIO **18.2** (Trailing: 17.6 Median: 15.0) | RELATIVE P/E RATIO **0.95** | DIV'D YLD **3.6%** | **VALUE LINE**

TIMELINESS **1** Raised 3/2/18
SAFETY **2** Raised 12/21/12
TECHNICAL **3** Lowered 2/23/18
BETA .65 (1.00 = Market)

2021-23 PROJECTIONS

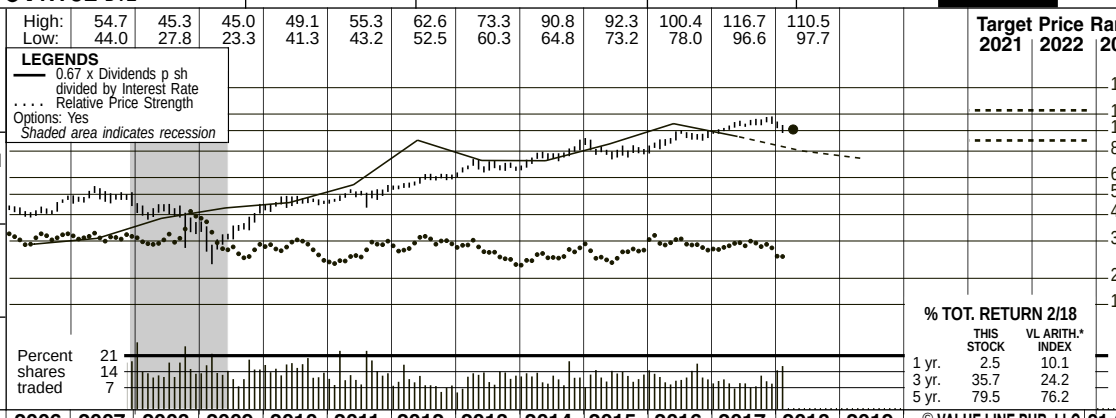
	Price	Gain	Ann'l Total Return
High	125	(+25%)	9%
Low	90	(-10%)	2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	2	0	0	0	1	0	7
to Sell	2	2	1	2	0	0	1	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	257	252	223
to Sell	242	249	225
Hld's(000)	139403	138883	123868



2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
40.30	41.76	40.84	50.74	50.93	54.28	57.23	48.45	50.51	52.57	51.01	54.56	69.50	57.60	59.24	70.28	*71.25*	*71.35*	Revenues per sh	*81.00*
8.31	6.95	6.81	8.14	8.19	8.48	8.26	9.38	9.78	9.57	9.77	10.13	11.85	9.44	10.60	11.77	*12.20*	*12.65*	"Cash Flow" per sh	*15.50*
3.83	2.85	2.55	3.27	2.45	2.66	2.73	3.24	3.74	3.67	3.88	3.76	5.10	4.44	4.83	5.73	*5.80*	*6.20*	Earnings per sh [A]	*7.50*
2.06	2.06	2.06	2.06	2.08	2.12	2.12	2.12	2.18	2.32	2.42	2.59	2.69	2.84	3.06	3.36	*3.59*	*3.84*	Div'd Decl'd per sh [B] ■	*4.55*
5.88	4.45	5.19	5.99	7.92	7.96	8.42	6.26	6.49	8.77	10.56	10.59	11.58	11.26	11.40	12.54	*19.50*	*13.30*	Cap'l Spending per sh	*13.25*
27.26	31.36	31.85	32.44	33.02	35.86	36.77	37.96	39.67	41.41	42.78	44.73	47.05	48.88	50.22	53.03	*55.95*	*60.05*	Book Value per sh [C]	*68.50*
167.46	168.61	174.21	177.81	177.14	163.23	163.02	165.40	169.43	169.25	172.35	177.09	176.99	179.47	179.43	179.39	*182.50*	*192.00*	Common Shs Outst'g [D]	*195.00*
11.3	13.7	16.0	13.8	17.4	18.3	14.8	10.4	12.3	13.5	14.9	17.9	14.9	18.1	19.0	18.6	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*14.5*
.62	.78	.85	.73	.94	.97	.89	.69	.78	.85	.95	1.01	.78	.91	1.00	.92			Relative P/E Ratio	*.80*
4.8%	5.3%	5.0%	4.6%	4.9%	4.4%	5.2%	6.3%	4.8%	4.7%	4.2%	3.8%	3.5%	3.5%	3.3%	3.2%			Avg Ann'l Div'd Yield	*4.2%*
9329.0	8014.0	8557.0	8897.0	8791.0	9661.0	12301	10337	10630	12607	*13000*	*13700*	Revenues ($mill)	*15800*
445.0	532.0	630.0	624.0	666.0	661.0	905.0	796.0	868.0	1029.0	*1050*	*1165*	Net Profit ($mill)	*1445*
34.9%	31.6%	32.7%	35.9%	29.8%	27.5%	28.5%	25.6%	24.5%	21.8%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
11.2%	2.6%	1.6%	1.6%	3.0%	3.5%	4.1%	4.3%	3.6%	3.5%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*2.0%*
56.4%	54.0%	51.3%	50.6%	48.8%	47.7%	50.0%	50.2%	55.6%	56.2%	*55.0%*	*54.0%*	Long-Term Debt Ratio	*55.0%*
43.6%	46.0%	48.7%	49.4%	51.2%	52.3%	50.0%	49.8%	44.4%	43.8%	*45.0%*	*46.0%*	Common Equity Ratio	*45.0%*
13736	13648	13811	14196	14387	15135	16670	17607	20280	21697	*22800*	*24975*	Total Capital ($mill)	*29600*
12231	12431	12992	13746	14684	15800	16820	18034	19730	20721	*23100*	*24375*	Net Plant ($mill)	*27700*
5.0%	5.7%	6.3%	5.9%	6.1%	5.7%	6.6%	5.7%	5.3%	5.9%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
7.4%	8.5%	9.4%	8.9%	9.0%	8.3%	10.9%	9.1%	9.6%	10.8%	*10.5%*	*10.0%*	Return on Shr. Equity	*11.0%*
7.4%	8.5%	9.4%	8.9%	9.0%	8.3%	10.9%	9.1%	9.6%	10.8%	*10.5%*	*10.0%*	Return on Com Equity [E]	*11.0%*
1.7%	2.9%	4.0%	3.4%	3.5%	2.7%	5.2%	3.4%	3.7%	4.6%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
77%	65%	57%	62%	61%	67%	52%	63%	61%	58%	*62%*	*62%*	All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $12915 mill. **Due in 5 Yrs** $3989 mill.
LT Debt $12185 mill. **LT Interest** $487 mill.
Incl. $1 mill. capitalized leases and $756 mill. Trust Preferred Securities.
(LT interest earned: 3.6x)

Leases, Uncapitalized Annual rentals $40 mill.
Pension Assets-12/17 $4636 mill.
Oblig $5576 mill.

Pfd Stock None
Common Stock 179,385,962 shs.

MARKET CAP: $18 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.6	+3.5	-3.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	279	300	300

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	2.0%	4.0%	*4.5%*
"Cash Flow"	2.5%	2.0%	*6.0%*
Earnings	6.0%	6.0%	*6.5%*
Dividends	4.0%	6.0%	*6.5%*
Book Value	4.0%	4.0%	*5.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	2984	2268	2598	2487	10337
2016	2566	2262	2928	2874	10630
2017	3236	2855	3245	3271	12607
2018	*3350*	*2950*	*3400*	*3300*	*13000*
2019	*3550*	*3050*	*3600*	*3500*	*13700*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.53	.61	1.47	.83	4.44
2016	1.37	.84	1.88	.73	4.83
2017	2.23	.99	1.51	1.01	5.73
2018	*1.90*	*1.00*	*1.65*	*1.25*	*5.80*
2019	*2.00*	*1.10*	*1.75*	*1.35*	*6.20*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.655	.655	.655	.69	2.66
2015	.69	.69	.69	.73	2.80
2016	.73	.73	.73	.77	2.96
2017	.825	.825	.825	.825	3.30
2018	.8825				

BUSINESS: DTE Energy Company is a holding company for DTE Electric (formerly Detroit Edison), which supplies electricity in Detroit and a 7,600-square-mile area in southeastern Michigan, and DTE Gas (formerly Michigan Consolidated Gas). Customers: 2.1 mill. electric, 1.3 mill. gas. Has various nonutility operations. Electric revenue breakdown: residential, 46%; commercial, 35%; industrial, 13%; other, 6%. Generating sources: coal, 67%; nuclear, 17%; gas, 1%; purchased, 15%. Fuel costs: 57% of revenues. '17 reported deprec. rates: 3.6% electric, 2.7% gas. Has 10,200 employees. Chairman & CEO: Gerard M. Anderson. President & COO: Jerry Norcia. Inc.: MI. Address: One Energy Plaza, Detroit, MI 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

DTE Energy's electric utility subsidiary should get a rate order by the end of April. DTE Electric is seeking a tariff hike of $231 million, based on a 10.5% return on equity. The company self-implemented a $125 million increase at the start of November. The staff of the Michigan Public Service Commission (MPSC) recommended a $71 million, based on a 9.8% ROE. An administrative law judge proposed an increase of $12 million that is based on a 9.6% ROE.

Another regulatory ruling is expected next month. DTE Electric asked the MPSC for a certificate of need to build a 1,100-megawatt gas-fired plant at a cost of $989 million. This would replace the coal-fired capacity that DTE Electric plans to retire by 2022.

DTE Gas has a rate case pending. The utility filed for an increase of $85 million, based on a 10.5% ROE. It also wants to accelerate its gas main-replacement program from 25 years to 15 years. The MPSC's order is due by late September.

The new federal tax law is benefiting earnings. The revaluation of deferred taxes boosted share net by $0.59 in the fourth quarter of 2017, which is excluded from our presentation. This year, the lower tax rate will augment the income of DTE's nonutility operations, thereby lifting earnings by an estimated $0.10 a share. (This is why management raised its guidance from $5.48-$5.88 to $5.57-$5.99.) However, because the electric and gas utilities will pass their tax reductions through to customers, this will hurt cash flow. Accordingly, DTE Energy will issue an additional $300 million of common equity over the next three years.

We forecast solid earnings growth in 2019. The utilities will benefit from a full year's effect of the rate hikes obtained in 2018. The nonutility subsidiaries are expanding their pipeline capacity and adding projects (such as cogeneration facilities) with industrial customers. Our estimate of $6.20 a share would produce growth within the company's target of 5%-7%.

This timely stock has a dividend yield equal to the utility average. Like most utility stocks, the recent price is within our 2021-2023 Target Price Range. Thus, total return potential is unspectacular.

Paul E. Debbas, CFA *March 16, 2018*

(A) Diluted EPS. Excl. nonrec. gains (losses): '03, (16¢); '05, (2¢); '06, 1¢; '07, $1.96; '08, 50¢; '11, 51¢; '15, (39¢); '17, 59¢; gains (losses) on disc. ops.: '03, 40¢; '04, (6¢); '05, (20¢); '06, (2¢); '07, $1.20; '08, 13¢; '12, (33¢). '16-'17 EPS don't sum due to rounding. Next egs. due late Apr. **(B)** Div'ds pd. mid-Jan., Apr., July & Oct. ■ Div'd reinvest. plan avail. **(C)** Incl. intang. In '17: $38.37/sh. **(D)** In mill. **(E)** Rate base: Net orig. cost. Rate all'd on com. eq. in '17: 10.1% elec.; in '16: 10.1% gas; earned on avg. com. eq., '17: 12.2%. Regul. Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	80

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DUKE ENERGY NYSE-DUK

RECENT PRICE **77.88** | P/E RATIO **16.2** (Trailing: 17.8 / Median: 18.0) | RELATIVE P/E RATIO **0.91** | DIV'D YLD **4.7%** | **VALUE LINE**

TIMELINESS **3** Raised 3/2/18
SAFETY **2** New 6/1/07
TECHNICAL **4** Raised 5/18/18
BETA .60 (1.00 = Market)

2021-23 PROJECTIONS

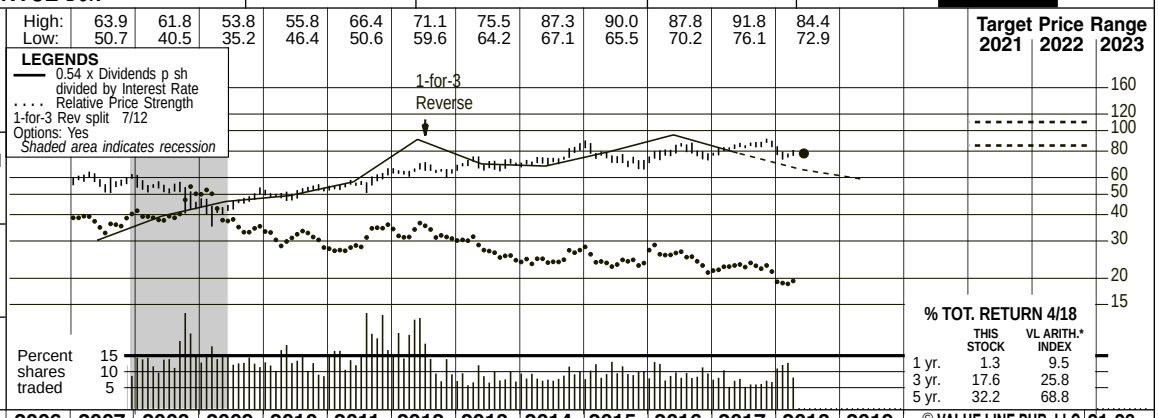
	Price	Gain	Ann'l Total Return
High	110	(+40%)	*13%*
Low	85	(+10%)	*7%*

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	8	9
to Sell	0	1	0	0	1	0	0	0	1

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	528	531	531
to Sell	509	494	467
Hld's(000)	435858	442941	402762



2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
--	--	--	--	25.32	30.24	31.15	29.18	32.22	32.63	27.88	34.84	33.84	34.10	32.49	33.66	***33.45***	***34.20***	Revenues per sh	***36.50***
--	--	--	--	7.86	8.11	7.34	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	10.01	***11.15***	***11.70***	"Cash Flow" per sh	***13.25***
--	--	--	--	2.76	3.60	3.03	3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	4.22	***4.80***	***5.00***	Earnings per sh [A]	***5.50***
--	--	--	--	--	2.58	2.70	2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.49	***3.64***	***3.80***	Div'd Decl'd per sh [B] ■	***4.40***
--	--	--	--	8.07	7.43	10.35	9.85	10.84	9.80	7.81	7.83	7.62	9.83	11.29	11.50	***15.05***	***15.00***	Cap'l Spending per sh	***11.75***
--	--	--	--	62.30	50.40	49.51	49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.62	59.63	***61.05***	***62.35***	Book Value per sh [C]	***66.00***
--	--	--	--	418.96	420.62	423.96	436.29	442.96	445.29	704.00	706.00	707.00	688.00	700.00	700.00	***727.00***	***731.50***	Common Shs Outst'g [D]	***745.00***
--	--	--	--	--	16.1	17.3	13.3	12.7	13.8	17.5	17.4	17.9	18.2	21.3	19.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	***18.0***
--	--	--	--	--	.85	1.04	.89	.81	.87	1.11	.98	.94	.92	1.12	.99			Relative P/E Ratio	***1.00***
--	--	--	--	--	4.4%	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	4.2%			Avg Ann'l Div'd Yield	***4.5%***
13207	12731	14272	14529	19624	24598	23925	23459	22743	23565	***24300***	***25000***	Revenues ($mill)	***27200***
1279.0	1461.0	1765.0	1839.0	2136.0	2813.0	2934.0	2854.0	2560.0	2963.0	***3435***	***3640***	Net Profit ($mill)	***4100***
32.5%	34.4%	32.6%	31.3%	30.2%	32.6%	30.6%	32.2%	31.0%	30.4%	***15.5%***	***15.5%***	Income Tax Rate	***15.5%***
16.0%	17.5%	22.7%	23.2%	22.3%	8.8%	7.2%	9.2%	11.7%	12.3%	***11.0%***	***11.0%***	AFUDC % to Net Profit	***10.0%***
38.7%	42.6%	44.3%	45.1%	47.0%	48.0%	47.7%	48.6%	52.6%	54.0%	***54.0%***	***55.0%***	Long-Term Debt Ratio	***56.5%***
61.3%	57.4%	55.7%	54.9%	52.9%	52.0%	52.3%	51.4%	47.4%	46.0%	***46.0%***	***45.0%***	Common Equity Ratio	***43.5%***
34238	37863	40457	41451	77307	79482	78088	77222	86609	90774	***97000***	***101475***	Total Capital ($mill)	***112500***
34036	37950	40344	42661	68558	69490	70046	75709	82520	86391	***92675***	***98725***	Net Plant ($mill)	***108700***
4.8%	4.9%	5.5%	5.6%	3.6%	4.6%	4.8%	4.8%	4.0%	4.3%	***4.5%***	***4.5%***	Return on Total Cap'l	***5.0%***
6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	***7.5%***	***8.0%***	Return on Shr. Equity	***8.5%***
6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	***7.5%***	***8.0%***	Return on Com Equity [E]	***8.5%***
.6%	1.1%	2.1%	2.2%	.9%	1.5%	1.7%	1.5%	.6%	1.2%	***2.0%***	***2.0%***	Retained to Com Eq	***1.5%***
89%	84%	73%	72%	82%	78%	76%	79%	91%	83%	***76%***	***76%***	All Div'ds to Net Prof	***80%***

CAPITAL STRUCTURE as of 12/31/17
Total Debt $54442 mill. **Due in 5 Yrs** $19439 mill.
LT Debt $49035 mill. **LT Interest** $1790 mill.
Incl. $1000 mill. capitalized leases.
(LT interest earned: 3.1x)

Leases, Uncapitalized Annual rentals $218 mill.
Pension Assets-12/17 $9003 mill.
Oblig $8448 mill.

Pfd Stock None

Common Stock 700,092,667 shs.
as of 1/31/18
MARKET CAP: $55 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+.6	-.3	-2.0
Avg. Indust. Use (MWH)	2883	2908	2914
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+1.2	+1.4	+1.3
Fixed Charge Cov. (%)	317	264	272

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	2.0%	1.5%	*1.5%*
"Cash Flow"	2.0%	3.5%	*5.5%*
Earnings	2.5%	.5%	*5.5%*
Dividends	10.0%	2.5%	*4.5%*
Book Value	.5%	2.0%	*2.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	6065	5589	6483	5322	23459
2016	5377	5213	6576	5577	22743
2017	5729	5555	6482	5799	23565
2018	6135	***5650***	***6665***	***5850***	***24300***
2019	***6300***	***5750***	***6950***	***6000***	***25000***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.09	.87	1.44	.70	4.10
2016	.83	.90	1.44	.54	3.71
2017	1.02	.98	1.36	.86	4.22
2018	1.17	***1.03***	***1.55***	***1.05***	***4.80***
2019	***1.20***	***1.10***	***1.60***	***1.10***	***5.00***

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.78	.78	.795	.795	3.15
2015	.795	.795	.825	.825	3.24
2016	.825	.825	.855	.855	3.36
2017	.855	.855	.89	.89	3.49
2018	.89				

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.4 mill. elec. customers in NC, FL, IN, SC, Oh, & KY, and 1.5 mill. gas customers in OH, KY, NC, SC, and TN. Owns independent power plants & has 25% stake in National Methanol in Saudi Arabia. Acq'd Progress Energy 7/12; Piedmont Natural Gas 10/16; discontinued most int'l ops. in '16. Elec. rev. breakdown: residential, 41%; commercial, 29%; industrial, 14%; other, 16%. Generating sources: coal, 27%; nuclear, 27%; gas, 23%; other, 1%; purchased, 22%. Fuel costs: 30% of revs. '17 reported deprec. rate: 2.8%. Has 29,100 employees. Chairman, President & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Internet: www.duke-energy.com.

Duke Energy has received rate increases in two states. The settlement for its Progress Energy unit was approved by the North Carolina regulators. Rates were raised by $193 million, based on a return of 9.9% on a common-equity ratio of 52%. However, certain costs were disallowed, including some associated with coal ash basin remediation. (Ongoing coal ash costs will be deferred, to be considered for recovery in the utility's next rate case.) This forced Duke to take a pretax charge of $100 million (*included* in our earnings presentation) in the first quarter. Separately, the utility was granted a tariff increase of $8.4 million in Kentucky, based on a return of 9.725% on a common-equity ratio of 49%.

Other regulatory matters are pending. Duke Energy Carolinas is seeking a hike of $647 million, based on a return of 10.75% on a common-equity ratio of 53%. New tariffs should take effect soon. In Ohio, Duke reached a settlement that would boost electric distribution rates by $19 million, based on a return of 9.84% on a common-equity ratio of 50.75%. The company is asking for new rates to take effect on June 1st.

Earnings are likely to advance significantly in 2018 and more modestly in 2019. The third-quarter comparison should be easy, as profits in that period of 2017 were hurt by mild weather patterns and some unusual (but not nonrecurring) costs. Our 2018 estimate of $4.80 a share is near the upper end of Duke's guidance of $4.55-$4.85 a share. Besides the easy comparison, rate relief should benefit the bottom line this year and next. We figure profits will advance 4%, to $5.00 a share, in 2019.

Duke executed a forward sale of common stock. The closing, by yearend, will raise more than $1.5 billion and will increase the share count by more than 21 million. The proceeds will be used for general corporate purposes.

This stock offers an attractive dividend yield. The yield is more than one percentage point above the utility mean. The respectable dividend growth we project over the 3- to 5-year period should produce total returns that are above average for a utility, as well.

Paul E. Debbas, CFA *May 18, 2018*

(A) Dil. EPS. Excl. nonrec. losses: '12, 70¢; '13, 24¢; '14, 67¢; '17, 15¢; '18, 11¢; gain (losses) on disc. ops.: '14, (80¢); '15, 5¢; '16, (60¢). '16 EPS don't sum due to rounding. Next egs. due early Aug. **(B)** Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. **(C)** Incl. intang. In '17: $45.48/sh. **(D)** In mill., adj. for rev. split. **(E)** Rate base: Net orig. cost. Rates all'd on com. eq. in '13 in NC: 10.2%; in '17 in SC: 10.1%; in '09 in OH: 10.63%; in '04 in IN: 10.3%; earn. avg. com. eq., '17: 7.1%. Reg. Clim.: NC Avg.; SC, OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	85

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EVERSOURCE ENERGY NYSE-ES

RECENT PRICE **57.32** | P/E RATIO **17.6** (Trailing: 18.3 Median: 17.0) | RELATIVE P/E RATIO **0.99** | DIV'D YLD **3.6%** | **VALUE LINE**

TIMELINESS **4** Lowered 5/18/18
SAFETY **1** Raised 5/22/15
TECHNICAL **4** Raised 5/18/18
BETA .65 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+30%)	*10%*
Low	60	(+5%)	*5%*

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	12	8	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	270	274	232
to Sell	253	232	234
Hld's(000)	253282	253377	231512

High:	33.6	31.6	26.5	32.2	36.5	40.9	45.7	56.7	56.8	60.4	66.1	65.0
Low:	26.2	17.2	19.0	24.7	30.0	33.5	38.6	41.3	44.6	50.0	54.1	55.9

LEGENDS
0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2021 | 2022 | 2023

% TOT. RETURN 4/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.7	9.5
3 yr.	36.4	25.8
5 yr.	57.1	68.8

Percent shares traded

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
40.89	47.53	51.82	41.85	44.64	37.27	37.22	30.97	27.76	25.21	19.98	23.16	24.42	25.08	24.11	24.46	*25.10*	*25.70*	Revenues per sh	*28.00*
6.32	5.80	5.00	5.46	3.69	4.82	6.16	4.96	5.68	4.88	4.03	5.22	4.56	4.94	5.46	5.84	*6.45*	*6.80*	"Cash Flow" per sh	*8.00*
1.08	1.24	.91	.98	.82	1.59	1.86	1.91	2.10	2.22	1.89	2.49	2.58	2.76	2.96	3.11	*3.25*	*3.45*	Earnings per sh [A]	*4.00*
.53	.58	.63	.68	.73	.78	.83	.95	1.03	1.10	1.32	1.47	1.57	1.67	1.78	1.90	*2.02*	*2.14*	Div'd Decl'd per sh [B] ■	*2.50*
3.86	4.31	4.85	5.89	5.49	7.14	8.06	5.17	5.41	6.08	4.69	4.62	5.06	5.44	6.24	7.41	*9.60*	*9.45*	Cap'l Spending per sh	*6.25*
17.33	17.73	17.80	18.46	18.14	18.65	19.38	20.37	21.60	22.65	29.41	30.49	31.47	32.64	33.80	34.99	*36.25*	*37.55*	Book Value per sh [C]	*42.00*
127.56	127.70	129.03	131.59	154.23	156.22	155.83	175.62	176.45	177.16	314.05	315.27	316.98	317.19	316.89	316.89	*316.89*	*316.89*	Common Shs Outst'g [D]	*316.89*
16.1	13.4	20.8	19.8	27.1	18.7	13.7	12.0	13.4	15.4	19.9	16.9	17.9	18.1	18.7	19.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.0*
.88	.76	1.10	1.05	1.46	.99	.82	.80	.85	.97	1.27	.95	.94	.91	.98	.97			Relative P/E Ratio	*.95*
3.0%	3.5%	3.3%	3.5%	3.3%	2.6%	3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	3.4%	3.3%	3.2%	3.1%			Avg Ann'l Div'd Yield	*3.7%*
5800.1	5439.4	4898.2	4465.7	6273.8	7301.2	7741.9	7954.8	7639.1	7752.0	*7950*	*8150*	Revenues ($mill)	*8850*
296.2	335.6	377.8	400.3	533.0	793.7	827.1	886.0	949.8	995.5	*1040*	*1110*	Net Profit ($mill)	*1290*
29.7%	34.9%	36.6%	29.9%	34.0%	35.0%	36.2%	37.9%	36.9%	36.8%	*23.5%*	*23.5%*	Income Tax Rate	*23.5%*
15.8%	4.6%	7.1%	8.6%	2.3%	1.4%	2.4%	2.9%	3.9%	4.7%	*4.0%*	*3.0%*	AFUDC % to Net Profit	*2.0%*
60.4%	57.2%	55.1%	53.4%	43.7%	44.3%	45.9%	45.6%	44.8%	51.2%	*51.5%*	*52.5%*	Long-Term Debt Ratio	*54.5%*
38.1%	41.5%	43.6%	45.3%	55.4%	54.8%	53.2%	53.6%	54.4%	48.2%	*47.5%*	*47.0%*	Common Equity Ratio	*44.5%*
7926.2	8629.5	8741.8	8856.0	16675	17544	18738	19313	19697	23018	*24100*	*25325*	Total Capital ($mill)	*29800*
8207.9	8840.0	9567.7	10403	16605	17576	18647	19892	21351	23617	*25800*	*27900*	Net Plant ($mill)	*31600*
5.4%	5.4%	5.8%	5.9%	4.2%	5.5%	5.3%	5.5%	5.8%	5.2%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
9.4%	9.1%	9.6%	9.7%	5.7%	8.1%	8.2%	8.4%	8.7%	8.9%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
9.6%	9.2%	9.8%	9.8%	5.7%	8.2%	8.2%	8.5%	8.8%	8.9%	*9.0%*	*9.0%*	Return on Com Equity [E]	*9.5%*
5.3%	4.7%	5.0%	5.0%	1.6%	3.4%	3.5%	3.4%	3.5%	3.5%	*3.5%*	*3.5%*	Retained to Com Eq	*3.5%*
45%	50%	49%	50%	72%	59%	58%	61%	60%	61%	*62%*	*62%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 3/31/18
Total Debt $14162 mill. **Due in 5 Yrs** $4807.7 mill.
LT Debt $12016 mill. **LT Interest** $480.6 mill.
(LT interest earned: 4.5x)
Leases, Uncapitalized Annual rentals $13.2 mill.
Pension Assets-12/17 $4739.5 mill.
Oblig $5936.5 mill.
Pfd Stock $155.6 mill. **Pfd Div'd** $7.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption, call. at $50.50-$4.00; 430,000 shs 4.25%-4.78% not subject to mandatory redemption, call. at $102.80-$103.63.
Common Stock 316,885,808 shs. **as of 4/30/18**
MARKET CAP: $18 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+.3	-1.8	-2.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.86	6.04	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	447	436	427

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-5.0%	- -	*2.0%*
"Cash Flow"	1.5%	2.0%	*6.5%*
Earnings	10.0%	7.5%	*5.5%*
Dividends	9.5%	9.0%	*6.0%*
Book Value	6.5%	6.5%	*3.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	2513	1817	1933	1691	7954.8
2016	2055	1767	2039	1776	7639.1
2017	2105	1762	1988	1895	7752.0
2018	2288	*1800*	*2000*	*1862*	*7950*
2019	*2350*	*1850*	*2050*	*1900*	*8150*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.80	.65	.74	.57	2.76
2016	.77	.64	.83	.72	2.96
2017	.82	.72	.82	.75	3.11
2018	.85	*.75*	*.90*	*.75*	*3.25*
2019	*.90*	*.80*	*.95*	*.80*	*3.45*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.393	.393	.393	.393	1.57
2015	.4175	.4175	.4175	.4175	1.67
2016	.445	.445	.445	.445	1.78
2017	.475	.475	.475	.475	1.90
2018	.505				

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of utilities that have 3.1 mill. electric, 504,000 gas, 230,000 water customers. Supplies power to most of Connecticut and gas to part of Connecticut; supplies power to 3/4 of New Hampshire's population; supplies power to western Massachusetts and parts of eastern Massachusetts & gas to central & eastern Massachusetts; supplies water to CT, MA, & NH. Acq'd NSTAR 4/12; Aquarion 12/17. Electric rev. breakdown: residential, 51%; commercial, 36%; industrial, 5%; other, 8%. Fuel costs: 33% of revs. '17 reported deprec. rate: 3.0%. Has 8,100 empls. Chairman, Pres. & CEO: James J. Judge. Inc.: MA. Address: 300 Cadwell Drive, Springfield, MA 01104. Tel.: 413-785-5871. Internet: www.eversource.com.

Eversource Energy wants to expand its presence in the water utility business. The company, which acquired Aquarion in December of 2017, made a hostile takeover offer for Connecticut Water Service, which has agreed to be acquired by SJW Group, a water company in California. Eversource is offering $63.50 a share ($767 million), which shareholders may take in cash or stock, for the company, and is asking Connecticut Water stockholders to vote against the SJW deal. Connecticut Water would be a good geographic fit with Eversource's operations, but we aren't assuming that the hostile offer will turn friendly — or that regulators would approve the deal if it does turn friendly.

We estimate that earnings will climb at a mid-single-digit pace in 2018 and 2019. Eversource should benefit from rate relief in Massachusetts and Connecticut; spending on its electric transmission system, which provides an immediate return on its investment; expense-reduction measures; the addition of Aquarion; and conversions of oil-heating customers to natural gas. Our 2018 share-earnings estimate is at the midpoint of Eversource's targeted range of $3.20-$3.30. We look for profit growth in 2019 in line with management's annual goal of 5%-7%.

There is good and bad news concerning electric transmission. A few years ago, the Federal Energy Regulatory Commission (FERC) lowered the allowed return on equity for transmission owners in New England, following complaints that allowed ROEs were too generous. There is concern about additional cuts, but an administrative law judge for FERC ruled that the current allowed ROE (10.57% with an incentive cap of 11.74%) is not unjust or unreasonable. A decision from FERC is pending. On the other hand, a proposed transmission project to connect New England with Quebec failed to receive approval from the site evaluation committee in New Hampshire. Eversource has asked the committee for reconsideration, and might well appeal the matter to the state Supreme Court if this is denied.

This untimely stock has a dividend yield that is average, by utility standards. Total return potential to 2021-2023 is a cut above the mean for this industry.

Paul E. Debbas, CFA *May 18, 2018*

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	85

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(A) Dil. EPS. Excl. nonrec. gains (losses): '02, 10¢; '03, (32¢); '04, (7¢); '05, ($1.36); '08, (19¢); '10, 9¢. Next earnings report due early Aug. **(B)** Div'ds historically paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. **(C)** Incl. def'd charges. In '17: $28.16 sh. **(D)** In mill. **(E)** Rate allowed on com. eq. in MA: (elec) '18, 10.0%; (gas) '16, 9.8%; in CT: (elec.) '18, 9.25%; (gas) '15, 9.5%; in NH: '10, 9.67%; earned on avg. com. eq., '17: 9.1%. Regulatory Climate: CT, Below Average; NH, Average; MA, Above Average.

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EXELON CORP. NYSE-EXC

RECENT PRICE **40.74** | P/E RATIO **15.7** (Trailing: 16.0 / Median: 14.0) | RELATIVE P/E RATIO **0.88** | DIV'D YLD **3.6%** | **VALUE LINE**

TIMELINESS **3** Lowered 5/18/18
SAFETY **3** Lowered 11/23/12
TECHNICAL **3** Lowered 2/23/18
BETA .70 (1.00 = Market)

2021-23 PROJECTIONS

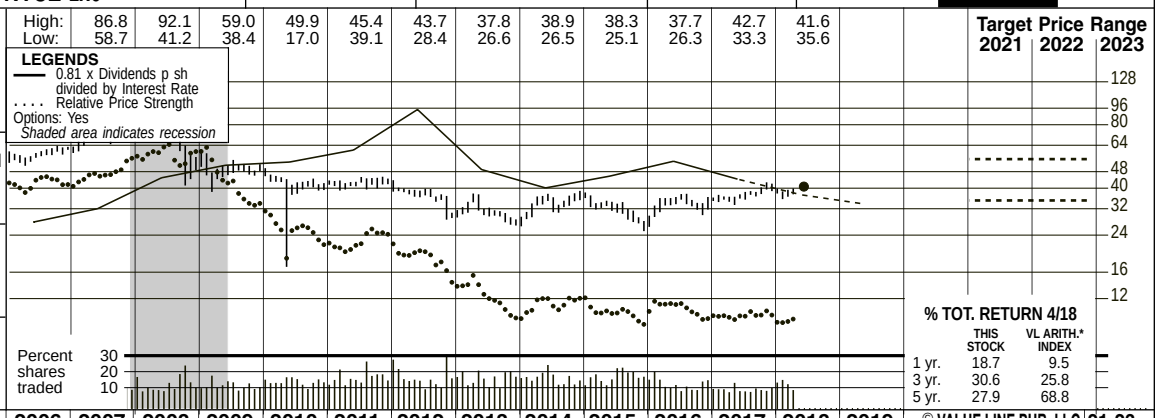
	Price	Gain	Ann'l Total Return
High	55	(+35%)	*11%*
Low	35	(-15%)	*Nil*

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	0	1	1	0	11	0	0
to Sell	1	1	2	1	1	1	0	0	1

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	392	357	360
to Sell	328	363	319
Hld's(000)	815779	816164	750206



% TOT. RETURN 4/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.7	9.5
3 yr.	30.6	25.8
5 yr.	27.9	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
23.13	24.09	21.85	23.05	23.37	28.62	28.65	26.25	28.17	28.53	27.48	29.03	31.90	32.01	33.94	34.81	*36.90*	*39.40*	Revenues per sh	*46.50*
5.03	5.06	5.68	6.19	6.71	7.43	7.64	8.25	8.32	7.23	6.61	6.72	6.61	6.80	7.01	8.37	*8.95*	*9.90*	"Cash Flow" per sh	*11.75*
2.40	2.44	2.75	3.21	3.50	4.03	4.10	4.29	3.87	3.75	1.92	2.31	2.10	2.54	1.80	2.78	*2.60*	*3.15*	Earnings per sh [A]	*3.75*
.88	.96	1.26	1.60	1.64	1.82	2.05	2.10	2.10	2.10	2.10	1.46	1.24	1.24	1.26	1.31	*1.38*	*1.45*	Div'd Decl'd per sh [B] ■	*1.70*
3.33	2.98	2.89	3.25	3.61	4.05	4.74	4.96	5.03	6.09	6.77	6.29	7.07	8.29	9.26	7.87	*8.15*	*7.20*	Cap'l Spending per sh	*7.25*
11.97	12.95	14.19	13.69	14.89	15.34	16.78	19.16	20.49	21.68	25.07	26.52	26.29	28.04	27.96	30.99	*32.25*	*34.00*	Book Value per sh [C]	*39.75*
646.63	656.37	664.19	666.37	669.86	660.88	658.15	659.76	661.85	663.37	854.78	857.29	859.83	919.92	924.04	963.34	*967.00*	*970.00*	Common Shs Outst'g [D]	*980.00*
10.5	11.8	13.0	15.4	16.5	18.2	18.0	11.5	11.0	11.3	19.1	13.4	16.0	12.6	18.7	13.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*12.0*
.57	.67	.69	.82	.89	.97	1.08	.77	.70	.71	1.22	.75	.84	.63	.98	.67			Relative P/E Ratio	*.65*
3.5%	3.4%	3.5%	3.2%	2.8%	2.5%	2.8%	4.3%	4.9%	5.0%	5.7%	4.7%	3.7%	3.9%	3.7%	3.5%			Avg Ann'l Div'd Yield	*3.8%*
18859	17318	18644	18924	23489	24888	27429	29447	31360	33531	*35700*	*38200*	Revenues ($mill)	*45500*
2721.0	2844.0	2567.0	2499.0	1579.0	1999.0	1826.0	2282.0	1677.0	2636.0	*2570*	*3080*	Net Profit ($mill)	*3670*
32.6%	38.8%	39.2%	36.8%	32.4%	36.5%	27.2%	32.2%	38.5%	34.2%	*8.5%*	*8.5%*	Income Tax Rate	*8.5%*
1.3%	2.3%	2.1%	3.0%	5.8%	4.5%	5.5%	5.4%	12.3%	6.5%	*8.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
53.1%	47.2%	46.8%	45.7%	45.8%	44.4%	46.7%	48.3%	55.5%	52.2%	*52.5%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
46.6%	52.4%	52.9%	54.0%	53.5%	55.2%	52.8%	51.3%	44.5%	47.8%	*47.5%*	*50.0%*	Common Equity Ratio	*50.0%*
23726	24112	25651	26661	40057	41196	42811	50272	58053	62422	*65875*	*65750*	Total Capital ($mill)	*77900*
25813	27341	29941	32570	45186	47330	52087	57439	71555	74202	*76475*	*77425*	Net Plant ($mill)	*83600*
13.1%	13.3%	11.4%	10.6%	5.1%	5.9%	5.3%	5.5%	4.1%	5.3%	*5.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
24.4%	22.3%	18.8%	17.3%	7.3%	8.7%	8.0%	8.8%	6.5%	8.8%	*8.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
24.6%	22.5%	18.9%	17.3%	7.3%	8.7%	8.0%	8.8%	6.5%	8.8%	*8.0%*	*9.0%*	Return on Com Equity [E]	*9.5%*
12.5%	11.5%	8.7%	7.7%	NMF	3.2%	3.3%	4.5%	1.9%	4.7%	*4.0%*	*5.0%*	Retained to Com Eq	*5.0%*
49%	49%	54%	56%	109%	63%	59%	49%	70%	47%	*52%*	*46%*	All Div'ds to Net Prof	*45%*

CAPITAL STRUCTURE as of 3/31/18
Total Debt $35762 mill. **Due in 5 Yrs** $12889 mill.
LT Debt $32905 mill. **LT Interest** $1364 mill.
Includes $389 mill. nonrecourse transition bonds.
(LT interest earned: 3.8x)
Leases, Uncapitalized Annual rentals $188 mill.

Pension Assets-12/17 $18573 mill.
Oblig $22337 mill.

Pfd Stock None

Common Stock 965,381,919 shs.

MARKET CAP: $39 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-1.0	+25.8	-3.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Nuclear Capacity Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+33.7	+.9
Fixed Charge Cov. (%)	367	238	282

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	3.0%	3.5%	*5.5%*
"Cash Flow"	1.0%	- -	*8.0%*
Earnings	-4.0%	-5.5%	*8.0%*
Dividends	-3.0%	-9.5%	*5.0%*
Book Value	7.0%	5.5%	*5.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	8830	6514	7401	6702	29447
2016	7573	6910	9002	7875	31360
2017	8757	7623	8769	8382	33531
2018	9693	*8000*	*9207*	*8800*	*35700*
2019	*9900*	*8700*	*10000*	*9600*	*38200*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.80	.74	.69	.33	2.54
2016	.26	.45	.76	.33	1.80
2017	.83	.44	.95	.56	2.78
2018	.60	*.60*	*.90*	*.50*	*2.60*
2019	*1.00*	*.65*	*.95*	*.55*	*3.15*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.31	.31	.31	.31	1.24
2015	.31	.31	.31	.31	1.24
2016	.31	.318	.318	.318	1.26
2017	.328	.328	.328	.328	1.31
2018	.345				

BUSINESS: Exelon Corporation is a holding company for Commonwealth Edison, PECO Energy, Baltimore Gas and Electric, Pepco, Delmarva Power, & Atlantic City Electric. Has 8.8 mill. elec., 1.3 mill. gas customers. Has nonregulated generating & energy-marketing ops. Acq'd Constellation Energy 3/12; Pepco Holdings 3/16. Elec. rev. breakdown: res'l, 53%; small comm'l & ind'l, 17%; large comm'l & ind'l, 15%; other, 15%. Generating sources: nuclear, 69%; other, 12%; purch., 19%. Fuel costs: 42% of revs. '17 depr. rates: 2.8%-7.0% elec., 2.1% gas. Has 34,600 empls. Chairman: Mayo A. Shattuck III. Pres. & CEO: Christopher M. Crane. Inc.: PA. Address: 10 S. Dearborn St., P.O. Box 805379, Chicago, IL 60680-5379. Tel.: 312-394-7398. Internet: www.exeloncorp.com.

Exelon's utilities are making progress in obtaining much-needed rate relief. When the company acquired Pepco Holdings in 2016, the utilities that came with the deal were not earning adequate returns on equity. So, they have filed multiple rate cases, and have completed or are on their second cycle of applications. Delmarva Power is seeking electric and gas increases totaling $16.5 million, based on a 10.1% return on equity. Rulings are expected in the second half of 2018. Pepco has reached settlements in Maryland and Washington, DC that would provide for rate decreases because the effects of tax reform outweigh the rate hikes that otherwise would occur. Besides these cases of the former Pepco Holdings, PECO is seeking an electric rate increase of $82 million, based on a 10.95% ROE. An order is expected in December.

The company's nonutility assets continue to face a challenging environment. The profitability of nonregulated nuclear assets has declined over the past several years due to low natural gas prices, subsidized renewable energy, and little growth in the demand for power. However, help has come in the way of subsidies for nuclear energy in Illinois and New York, in recognition that nuclear plants are carbon free and provide fuel diversity. Similar subsidies might be coming to New Jersey if the governor signs a bill that the legislature passed in April.

Our 2018 earnings estimate requires an explanation. We include things such as mark-to-market accounting items and gains or losses in the nuclear decommissioning trust because they are ongoing, even though Exelon excludes these from its earnings guidance of $2.90-$3.20 a share. Exelon's first-quarter "operating" earnings excludes $0.36 a share of costs that we included. This is why we estimate an earnings decline this year.

The board of directors raised the dividend. The annual increase was $0.07 a share (5.3%). We look for the same hike next year. Exelon's goal is 5% yearly dividend growth through 2020.

This stock has a dividend yield that is average for a utility. Total return potential to 2021-2023 is slightly above average for the industry.

Paul E. Debbas, CFA *May 18, 2018*

(A) Dil. egs. Excl. nonrec. gain (losses): '03, ($1.06); '05, ($1.85); '06, ($1.15); '09, (20¢); '12, (50¢); '13, (31¢); '14, 23¢; '16, (58¢); '17, $1.19. '15-'17 EPS don't add due to rounding or chg. in shs. Next earnings report due early Aug. **(B)** Div'ds paid in early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. **(C)** Incl. def'd chgs. In '17: $15.67/sh. **(D)** In mill. **(E)** Rate all'd on com. eq. in IL in '15: 9.25%; in MD in '16: 9.75% elec., 9.65% gas; in NJ in '16: 9.75%; earned on avg. com. eq., '17: 9.6%. Reg. Clim.: PA, NJ Avg.; IL, MD, Below Avg.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	10
Earnings Predictability	50

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EL PASO ELECTRIC NYSE-EE

RECENT PRICE **50.25** | P/E RATIO **20.4** (Trailing: 20.8 / Median: 15.0) | RELATIVE P/E RATIO **1.09** | DIV'D YLD **2.9%** | **VALUE LINE**

TIMELINESS **3** Lowered 1/26/18
SAFETY **2** Raised 5/11/07
TECHNICAL **3** Lowered 4/6/18
BETA .75 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+20%)	8%
Low	45	(-10%)	1%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	3	4	0	0	4	0	0	4	7
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	117	96	86
to Sell	78	83	67
Hld's(000)	45099	45123	39640

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	28.2	25.5	21.1	28.7	35.7	35.3	39.1	42.2	41.3	48.8	61.2	55.8						
Low:	20.8	15.2	11.6	18.7	26.7	29.2	31.8	33.4	33.8	37.2	44.7	48.1						

LEGENDS
0.90 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2021 | 2022 | 2023

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.5	9.7
3 yr.	43.5	24.3
5 yr.	75.1	68.8

Percent shares traded

13.91	13.97	14.95	16.70	17.75	19.43	23.15	18.85	20.61	22.97	21.26	22.11	22.74	21.01	21.89	22.59	***22.80***	***23.35***
2.99	3.00	3.27	3.05	3.44	3.86	4.16	4.07	5.15	6.05	5.66	5.65	5.87	5.75	5.98	6.17	***6.35***	***6.60***
.57	.64	.69	.76	1.27	1.63	1.73	1.50	2.07	2.48	2.26	2.20	2.27	2.03	2.39	2.42	***2.45***	***2.60***
- -	- -	- -	- -	- -	- -	- -	- -	- -	.66	.97	1.05	1.11	1.17	1.23	1.32	***1.42***	***1.52***
1.75	2.03	1.94	2.28	2.73	4.63	5.36	5.95	5.27	5.90	6.70	7.18	8.50	8.55	7.03	5.91	***6.80***	***6.85***
9.20	10.51	11.23	11.56	12.60	14.76	15.47	16.45	19.04	19.03	20.57	23.44	24.39	25.13	26.52	28.14	***29.20***	***30.25***
49.61	47.56	47.40	48.14	46.00	45.15	44.88	43.92	42.57	39.96	40.11	40.27	40.36	40.44	40.52	40.58	***40.60***	***40.70***
23.0	18.3	22.0	26.7	16.9	15.3	11.9	10.8	10.7	12.6	14.5	15.9	16.4	18.3	18.7	21.8		
1.26	1.04	1.16	1.42	.91	.81	.72	.72	.68	.79	.92	.89	.86	.92	.98	1.10		
- -	- -	- -	- -	- -	- -	- -	- -	- -	2.1%	3.0%	3.0%	3.0%	3.1%	2.7%	2.5%		
1038.9	828.0	877.3	918.0	852.9	890.4	917.5	849.9	886.9	916.8	***925***	***950***
77.6	66.9	90.3	103.5	90.8	88.6	91.4	81.9	96.8	98.3	***100***	***105***
32.8%	33.1%	36.1%	34.2%	34.1%	33.0%	31.0%	29.9%	35.8%	34.2%	***24.5%***	***24.5%***
20.4%	24.3%	22.1%	17.6%	22.4%	24.1%	30.8%	27.5%	17.6%	11.2%	***13.0%***	***12.0%***
53.8%	52.7%	51.2%	51.8%	54.8%	51.4%	53.5%	52.7%	52.7%	51.2%	***53.0%***	***52.0%***
46.2%	47.3%	48.8%	48.2%	45.2%	48.6%	46.5%	47.3%	47.3%	48.8%	***47.0%***	***48.0%***
1503.9	1527.7	1660.1	1576.7	1824.5	1943.5	2118.4	2150.8	2269.9	2338.2	***2530***	***2575***
1595.6	1756.0	1865.8	1947.1	2102.3	2257.5	2488.4	2695.5	2821.2	2928.4	***3045***	***3160***
6.7%	6.0%	7.0%	8.3%	6.5%	6.1%	5.7%	5.3%	5.8%	5.8%	***5.5%***	***5.5%***
11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	9.0%	8.6%	***8.5%***	***8.5%***
11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	9.0%	8.6%	***8.5%***	***8.5%***
11.2%	9.3%	11.1%	10.0%	6.3%	4.9%	4.8%	3.4%	4.4%	3.9%	***3.5%***	***3.5%***
- -	- -	- -	26%	43%	47%	49%	57%	51%	54%	***57%***	***58%***

Bold figures are Value Line estimates

© VALUE LINE PUB. LLC	21-23
Revenues per sh	*25.00*
"Cash Flow" per sh	*7.50*
Earnings per sh [A]	*3.00*
Div'd Decl'd per sh [B]	*1.85*
Cap'l Spending per sh	*7.25*
Book Value per sh [C]	*33.50*
Common Shs Outst'g [D]	*41.00*
Avg Ann'l P/E Ratio	*17.0*
Relative P/E Ratio	*.95*
Avg Ann'l Div'd Yield	*3.5%*
Revenues ($mill)	*1025*
Net Profit ($mill)	*125*
Income Tax Rate	*24.5%*
AFUDC % to Net Profit	*14.0%*
Long-Term Debt Ratio	*54.5%*
Common Equity Ratio	*45.5%*
Total Capital ($mill)	*3025*
Net Plant ($mill)	*3550*
Return on Total Cap'l	*6.0%*
Return on Shr. Equity	*9.0%*
Return on Com Equity [E]	*9.0%*
Retained to Com Eq	*3.5%*
All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $1369.5 mill. **Due in 5 Yrs** $218.5 mill.
LT Debt $1196.0 mill. **LT Interest** $72.3 mill.
(LT interest earned: 2.9x)

Pension Assets-12/17 $304.4 mill.
Oblig $362.0 mill.

Pfd Stock None

Common Stock 40,661,003 shs.
as of 1/31/18

MARKET CAP: $2.0 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+2.3	+.1	+.4
Avg. Indust. Use (MWH)	21687	21036	21553
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	2055	2080	2082
Peak Load, Summer (Mw)	1794	1892	1935
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.4	+1.6	+1.7
Fixed Charge Cov. (%)	218	267	263

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	2.0%	- -	*2.5%*
"Cash Flow"	5.5%	1.0%	*4.0%*
Earnings	6.5%	- -	*4.5%*
Dividends	- -	18.0%	*7.0%*
Book Value	7.5%	6.5%	*4.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	163.8	219.5	289.7	176.9	849.9
2016	157.8	217.9	323.2	188.0	886.9
2017	171.3	251.8	297.5	196.2	916.8
2018	*170*	*255*	*305*	*195*	*925*
2019	*175*	*260*	*315*	*200*	*950*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.09	.52	1.40	.02	2.03
2016	d.14	.55	1.84	.14	2.39
2017	d.10	.89	1.47	.16	2.42
2018	*d.15*	*.75*	*1.70*	*.15*	*2.45*
2019	*d.10*	*.80*	*1.75*	*.15*	*2.60*

QUARTERLY DIVIDENDS PAID [B]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.265	.28	.28	.28	1.11
2015	.28	.295	.295	.295	1.17
2016	.295	.31	.31	.31	1.23
2017	.31	.335	.335	.335	1.32
2018	.335				

BUSINESS: El Paso Electric Company (EPE) provides electric service to 417,000 customers in an area of approximately 10,000 square miles in the Rio Grande valley in western Texas (68% of revenues) and southern New Mexico (19% of revenues), including El Paso, Texas and Las Cruces, New Mexico. Wholesale is 13% of revenues. Electric revenue breakdown by customer class not available. Generating sources: nuclear, 49%; gas, 36%; purchased, 15%. Fuel costs: 27% of revenues. '17 reported depreciation rate: 2.3%. Has about 1,100 employees. Chairman: Charles A. Yamarone. President & CEO: Mary E. Kipp. Incorporated: Texas. Address: Stanton Tower, 100 North Stanton, El Paso, TX 79901. Tel.: 915-543-5711. Internet: www.epelectric.com.

We estimate that El Paso Electric Company's earnings will advance slightly this year. The utility will have a full year's worth of the rate increase in Texas that took effect in July of 2017. EPE is also benefiting from above-average customer growth that stems from the healthy economy in El Paso and environs. On the other hand, the weather was favorable for the company in 2017, and we assume normal weather this year. Our 2018 earnings estimate, which we lowered by $0.20 a share, is within management's guidance of $2.30-$2.65 a share. Next year, the utility will benefit from rate relief in Texas through transmission and distribution regulatory mechanisms. However . . .

Earnings have become less predictable. The company owns a 15.8% share of the Palo Verde nuclear station in Arizona. Like any utility that owns nuclear assets, EPE invests in a trust to provide funds for nuclear decommissioning. The gains or losses on the nuclear decommissioning trust are now being reflected in the income statement, instead of through Accumulated Other Comprehensive Income on the balance sheet. This will make earnings more volatile.

The utility is required to file a general rate case in New Mexico by July of 2019. EPE may file sooner; we note that the portion of Units 3 and 4 of a new gas-fired generating station that is allocated to New Mexico is not reflected in rates. However, the regulatory climate in New Mexico is difficult (not just for EPE), so the company might well wait until it is required to file before it puts forth its rate application.

We expect a dividend hike at the board meeting in May. This has been the pattern since the directors initiated a common dividend several years ago. We estimate an increase of $0.10 a share (7.5%) in the annual disbursement. EPE's goal is a payout ratio in a range of 55%-65%.

This stock has a dividend yield that is below the industry mean. Like many utility issues, the recent quotation is within our 2021-2023 Target Price Range. Accordingly, total return potential over that time frame is unspectacular, despite good dividend growth prospects.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted earnings. Excl. nonrecurring gains (loss): '03, 81¢; '04, 4¢; '05, (2¢); '06, 13¢; '10, 24¢. Next earnings report due early May. **(B)** Initial dividend declared 4/11; payment dates in late March, June, Sept., and Dec. **(C)** Incl. deferred charges. In '17: $96.0 mill., $2.37/sh. **(D)** In millions. **(E)** Rate allowed on common equity in TX in '17: 9.65%; in NM in '16: 9.48%; earned on avg. com. eq., '17: 8.9%. Regulatory Climate: TX, Average; NM, Below Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	70
Earnings Predictability	75

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EDISON INTERNAT'L NYSE-EIX

RECENT PRICE **65.22** | P/E RATIO **14.3** (Trailing: 14.5 Median: 12.0) | RELATIVE P/E RATIO **0.76** | DIV'D YLD **3.8%** | **VALUE LINE**

TIMELINESS **3** Lowered 3/2/18
SAFETY **2** Raised 5/3/13
TECHNICAL **4** Raised 4/20/18
BETA .60 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+55%)	*14%*
Low	75	(+15%)	*8%*

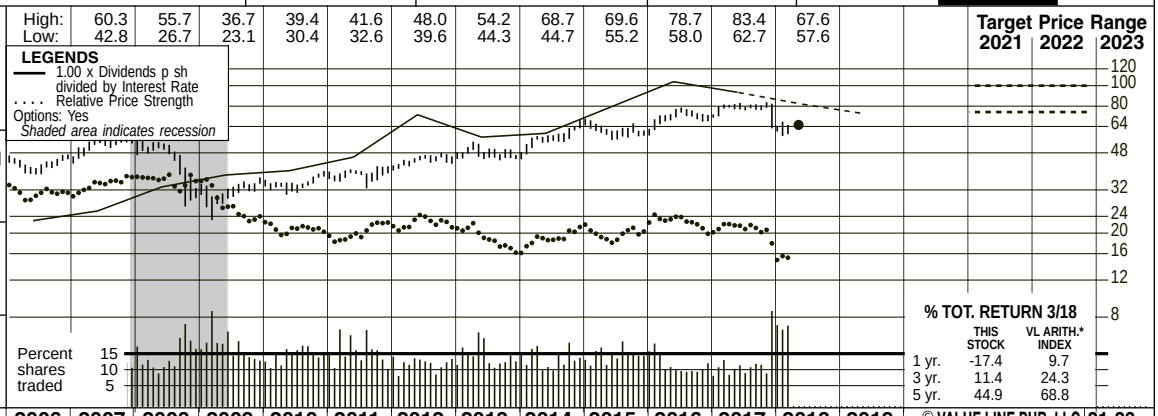
Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	2	0	1	0	0	1	0	11	0
to Sell	2	0	1	0	0	1	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	299	274	278
to Sell	236	258	225
Hld's(000)	290101	288374	267652

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
High:	60.3	55.7	36.7	39.4	41.6	48.0	54.2	68.7	69.6	78.7	83.4	67.6								
Low:	42.8	26.7	23.1	30.4	32.6	39.6	44.3	44.7	55.2	58.0	62.7	57.6								
	35.26	37.25	31.30	36.38	38.74	40.25	43.31	37.98	38.09	39.16	36.41	38.61	41.17	35.37	36.43	37.81	*38.35*	*40.20*	Revenues per sh	*46.75*
	4.79	5.88	3.79	6.99	7.25	7.60	8.08	7.96	8.41	9.03	9.63	8.80	9.95	10.35	10.43	11.03	*11.45*	*12.05*	"Cash Flow" per sh	*14.25*
	1.82	2.38	.69	3.34	3.28	3.32	3.68	3.24	3.35	3.23	4.55	3.78	4.33	4.15	3.94	4.51	*4.55*	*4.70*	Earnings per sh [A]	*5.50*
	- -	- -	.80	1.02	1.10	1.18	1.23	1.25	1.27	1.29	1.31	1.37	1.48	1.73	1.98	2.23	*2.45*	*2.57*	Div'd Decl'd per sh [B] ■	*3.10*
	4.88	3.95	5.32	5.73	7.78	8.67	8.67	10.07	13.94	14.76	12.73	11.05	11.99	12.97	11.46	11.75	*13.30*	*15.05*	Cap'l Spending per sh	*15.75*
	13.62	16.52	18.57	20.30	23.66	25.92	29.21	30.20	32.44	30.86	28.95	30.50	33.64	34.89	36.82	35.82	*37.35*	*38.90*	Book Value per sh [C]	*44.50*
	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	*325.81*	*325.81*	Common Shs Outst'g [D]	*325.81*
	7.8	7.0	37.6	11.7	13.0	16.0	12.4	9.7	10.3	11.8	9.7	12.7	13.0	14.8	17.9	17.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.5*
	.43	.40	1.99	.62	.70	.85	.75	.65	.66	.74	.62	.71	.68	.75	.94	.85			Relative P/E Ratio	*.85*
	- -	- -	3.1%	2.6%	2.6%	2.2%	2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.8%	2.8%	2.9%			Avg Ann'l Div'd Yield	*3.6%*
	14112	12374	12409	12760	11862	12581	13413	11524	11869	12320	*12500*	*13100*	Revenues ($mill)	*15200*
	1266.0	1115.0	1153.0	1112.0	1594.0	1344.0	1539.0	1480.0	1422.0	1603.0	*1620*	*1670*	Net Profit ($mill)	*1970*
	30.7%	33.0%	32.1%	25.7%	14.3%	25.2%	22.4%	6.6%	11.1%	5.0%	*10.0%*	*10.0%*	Income Tax Rate	*10.0%*
	8.9%	10.5%	16.9%	14.8%	8.5%	7.8%	5.8%	8.0%	6.8%	7.2%	*8.0%*	*7.0%*	AFUDC % to Net Profit	*7.0%*
	51.2%	49.3%	51.8%	55.3%	45.2%	45.7%	44.1%	45.0%	41.8%	45.6%	*48.0%*	*48.0%*	Long-Term Debt Ratio	*47.5%*
	44.5%	46.5%	44.3%	40.6%	46.2%	46.2%	47.2%	46.7%	49.2%	45.8%	*44.0%*	*44.5%*	Common Equity Ratio	*45.5%*
	21374	21185	23861	24773	20422	21516	23216	24352	24362	25506	*27500*	*28525*	Total Capital ($mill)	*31800*
	18969	21966	24778	32116	30273	30455	32981	35085	37000	39050	*41125*	*43675*	Net Plant ($mill)	*50700*
	7.4%	6.9%	6.3%	6.0%	8.9%	7.3%	7.7%	7.1%	6.9%	7.3%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.5%*
	12.1%	10.4%	10.0%	10.0%	14.2%	11.5%	11.9%	11.1%	10.0%	11.6%	*11.5%*	*11.0%*	Return on Shr. Equity	*12.0%*
	12.8%	10.8%	10.4%	10.5%	15.9%	12.5%	13.0%	12.0%	10.8%	12.7%	*12.5%*	*12.0%*	Return on Com Equity [E]	*12.5%*
	8.6%	6.7%	6.5%	6.3%	11.4%	8.1%	8.8%	7.2%	5.6%	6.6%	*5.5%*	*5.5%*	Retained to Com Eq	*6.0%*
	35%	41%	40%	43%	32%	40%	37%	44%	53%	52%	*57%*	*58%*	All Div'ds to Net Prof	*58%*



CAPITAL STRUCTURE as of 12/31/17
Total Debt $14516 mill. **Due in 5 Yrs** $4793 mill.
LT Debt $11642 mill. **LT Interest** $569 mill.
(LT interest earned: 4.0x)
Leases, Uncapitalized Annual rentals $335 mill.
Pens. Assets-12/17 $3616 mill. **Oblig** $4179 mill.
Pfd Stock $2193 mill. **Pfd Div'd** $124 mill.
4,800,198 sh. 4.08%-4.78%, $25 par, call. $25.50-$28.75/sh.; 3,250,000 sh. variable, noncum., call. $100; 1,250,000 sh. 6.5%, cum., $100 liq. value; 350,000 sh. 6.25%, $1000 liq. value; 460,012 sh. 5.1%-5.75%, $2500 liq. value.
Common Stock 325,811,206 shs. **as of 2/20/18**
MARKET CAP: $21 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-1.4	-2.6	+.2
Avg. Indust. Use (MWH)	703	664	NA
Avg. Indust. Revs. per KWH (¢)	9.07	6.51	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	23079	23091	23508
Annual Load Factor (%)	52.2	50.7	NA
% Change Customers (yr-end)	+.6	+.5	+.7
Fixed Charge Cov. (%)	247	246	241

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-.5%	-.5%	*4.0%*
"Cash Flow"	4.0%	3.5%	*5.0%*
Earnings	2.5%	2.5%	*4.5%*
Dividends	6.0%	9.0%	*8.0%*
Book Value	4.5%	3.0%	*3.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	2512	2908	3763	2341	11524
2016	2440	2777	3767	2885	11869
2017	2463	2965	3672	3220	12320
2018	*2500*	*3000*	*3800*	*3200*	*12500*
2019	*2600*	*3150*	*4000*	*3350*	*13100*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.91	1.15	1.15	.94	4.15
2016	.85	.86	1.27	.96	3.94
2017	1.11	.85	1.43	1.12	4.51
2018	*1.10*	*.90*	*1.45*	*1.10*	*4.55*
2019	*1.15*	*.90*	*1.50*	*1.15*	*4.70*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.355	.355	.355	.355	1.42
2015	.4175	.4175	.4175	.4175	1.67
2016	.48	.48	.48	.48	1.92
2017	.5425	.5425	.5425	.5425	2.17
2018	.605	.605			

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 5.1 mill. customers in a 50,000-sq.-mi. area in central, coastal, & southern CA (excl. Los Angeles & San Diego). Edison Energy is an energy svcs. co. Disc. Edison Mission Energy (independent power producer) in '12. Elec. rev. breakdown: residential, 37%; commercial, 44%; industrial, 6%; other, 13%. Generating sources: gas, 6%; nuclear, 6%; hydro, 5%; purchased, 83%. Fuel costs: 38% of revs. '17 reported depr. rate: 3.8%. Has 12,500 empls. Chairman: William P. Sullivan. Pres. & CEO: Pedro J. Pizzaro. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Web: www.edison.com.

Investors remain concerned about the possible wildfire liability of Edison International's utility subsidiary. Southern California Edison's service area had wildfires in the fall of 2017. The cause of the wildfires has not yet been determined, but SCE has already been hit with some lawsuits alleging that its power lines were at fault. (It has $1 billion in liability insurance.) Under California's inverse condemnation law, a utility can be held liable if its power lines contributed to the wildfires, even if the utility followed accepted inspection and safety rules. If this occurs, there is no assurance that the utility will be allowed to pass these costs through to ratepayers. So, the company is pursuing a three-pronged strategy to address this risk, seeking legislative, regulatory, and judicial solutions to this problem.

SCE is awaiting an order on its general rate case. The utility has revised its request to pass through to customers the benefits of federal tax reform. SCE is asking for a reduction of $106 million in 2018 and increases of $431 million and $503 million at the start of 2019 and 2020, respectively. (The order will be retroactive to the beginning of 2018.) The utility's three-year capital spending plan calls for $1.4 billion for grid modernization, which is somewhat controversial because the California commission has not been asked to approve such spending in previous rate cases. An order is expected by yearend.

Tax reform is slightly negative for the company. Edison International has about $1.75 billion of long-term debt at the parent level, so corporate interest and other expenses will have a lower tax shield. This is also true for the company's nonutility energy-services subsidiary, Edison Energy, which is still in its start-up phase and is in the red. Management estimates that the corporate and nonutility drag on earnings will amount to $0.25-$0.30 a share this year. Note that the company is not providing earnings guidance as long as the general rate case is pending.

The wildfire risks hurt the stock last year, and the price has risen just slightly in 2018. The dividend yield and 3- to 5-year total return potential are above average for this industry.

Paul E. Debbas, CFA *April 27, 2018*

(A) Dil. EPS. Excl. nonrec. gains (losses): '02, $1.48; '03, (12¢); '04, $2.12; '09, (64¢); '10, 54¢; '11, ($3.33); '13, ($1.12); '15, ($1.18); '17, ($1.37); gains (loss) from discontinued operations: '12, ($5.11); '13, 11¢; '14, 57¢; '15, 11¢. Next earnings report due late July. **(B)** Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan available. **(C)** Incl. deferred charges. In '17: $15.08/sh. **(D)** In millions. **(E)** Rate base: net orig. cost. Rate allowed on com. eq. in '15: 10.45%; earned on avg. com. eq., '17: 12.2%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	60

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ENTERGY CORP. NYSE-ETR

RECENT PRICE **77.72** | P/E RATIO **21.0** (Trailing: 15.0 / Median: 12.0) | RELATIVE P/E RATIO **1.10** | DIV'D YLD **4.6%** | **VALUE LINE**

TIMELINESS **3** Raised 12/29/17
SAFETY **3** Lowered 3/22/13
TECHNICAL **3** Lowered 3/2/18
BETA .65 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+30%)	*10%*
Low	65	(-15%)	*1%*

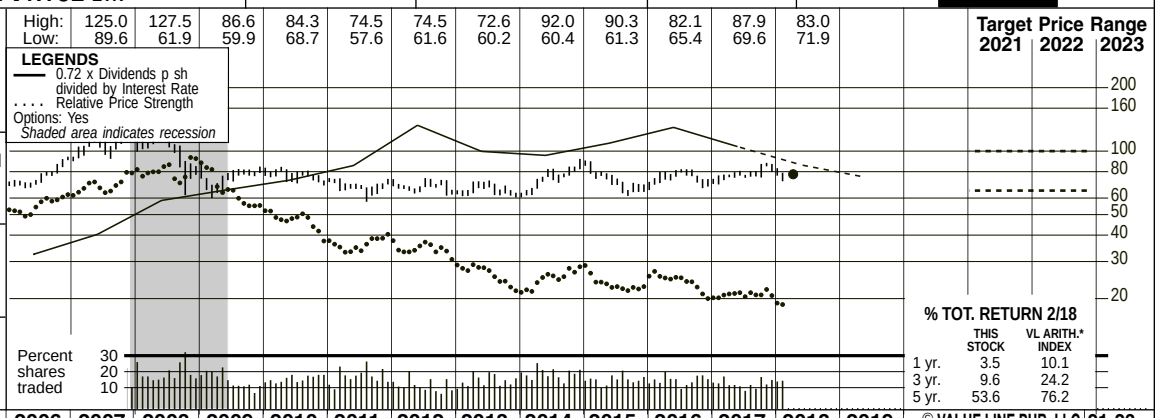
Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	10	0	0	8	6	4	8	15
to Sell	2	0	0	4	0	6	5	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	235	241	227
to Sell	264	245	225
Hld's(000)	167258	165036	154275

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
High:	125.0	127.5	86.6	84.3	74.5	74.5	72.6	92.0	90.3	82.1	87.9	83.0								
Low:	89.6	61.9	59.9	68.7	57.6	61.6	60.2	60.4	61.3	65.4	69.6	71.9								
	37.34	40.17	46.69	46.61	53.94	59.47	69.15	56.82	64.27	63.67	57.94	63.86	69.71	64.54	60.55	61.35	*59.00*	*55.95*	Revenues per sh	*55.00*
	7.62	7.43	8.33	8.18	10.69	11.73	12.89	13.29	16.54	17.53	15.98	16.25	17.68	17.71	18.72	16.70	*16.55*	*17.15*	"Cash Flow" per sh	*20.25*
	3.68	3.69	3.93	4.40	5.36	5.60	6.20	6.30	6.66	7.55	6.02	4.96	5.77	5.81	6.88	5.19	*4.25*	*5.20*	Earnings per sh A	*6.75*
	1.34	1.60	1.89	2.16	2.16	2.58	3.00	3.00	3.24	3.32	3.32	3.32	3.32	3.34	3.42	3.50	*3.58*	*3.66*	Div'd Decl'd per sh B ■ †	*3.90*
	6.88	6.85	6.51	6.72	9.44	10.29	13.92	12.99	13.33	15.21	18.18	15.73	14.82	16.79	17.28	22.07	*21.40*	*18.85*	Cap'l Spending per sh	*17.50*
	35.24	38.02	38.26	35.71	40.45	40.71	42.07	45.54	47.53	50.81	51.73	54.00	55.83	51.89	45.12	44.28	*45.75*	*48.80*	Book Value per sh C	*56.50*
	222.42	228.90	216.83	216.83	202.67	193.12	189.36	189.12	178.75	176.36	177.81	178.37	179.24	178.39	179.13	180.52	*183.00*	*193.00*	Common Shs Outst'g D	*193.00*
	11.5	13.8	15.1	16.3	14.3	19.3	16.6	12.0	11.6	9.1	11.2	13.2	12.9	12.5	10.9	15.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*12.5*
	.63	.79	.80	.87	.77	1.02	1.00	.80	.74	.57	.71	.74	.68	.63	.57	.75			Relative P/E Ratio	*.70*
	3.2%	3.1%	3.2%	3.0%	2.8%	2.4%	2.9%	4.0%	4.2%	4.9%	4.9%	5.1%	4.5%	4.6%	4.6%	4.5%			Avg Ann'l Div'd Yield	*4.7%*
	13094	10746	11488	11229	10302	11391	12495	11513	10846	11074	*10800*	*10800*	Revenues ($mill)	*10600*
	1240.5	1251.1	1270.3	1367.4	1091.9	904.5	1060.0	1061.2	1249.8	950.7	*7915*	*995*	Net Profit ($mill)	*1320*
	32.7%	33.6%	32.7%	17.3%	13.0%	26.7%	37.8%	2.2%	11.3%	1.8%	*25.5%*	*25.5%*	Income Tax Rate	*25.5%*
	5.6%	7.4%	7.4%	8.9%	11.9%	10.1%	9.3%	7.4%	8.1%	14.7%	*18.0%*	*13.0%*	AFUDC % to Net Profit	*9.0%*
	58.2%	55.3%	56.3%	52.2%	55.8%	55.1%	54.9%	57.8%	63.6%	63.6%	*63.0%*	*61.0%*	Long-Term Debt Ratio	*59.0%*
	40.2%	43.1%	42.1%	46.4%	42.9%	43.6%	43.8%	40.8%	35.5%	35.5%	*36.0%*	*38.5%*	Common Equity Ratio	*40.5%*
	19795	19985	20166	19324	21432	22109	22842	22714	22777	22528	*23200*	*24500*	Total Capital ($mill)	*27000*
	22429	23389	23848	25609	27299	27882	28723	27824	27921	29664	*31400*	*32750*	Net Plant ($mill)	*35500*
	7.5%	7.6%	7.7%	8.5%	6.4%	5.4%	6.0%	6.0%	6.9%	5.7%	*5.0%*	*5.5%*	Return on Total Cap'l	*6.5%*
	15.0%	14.0%	14.4%	14.8%	11.5%	9.1%	10.3%	11.1%	15.1%	11.6%	*9.5%*	*10.5%*	Return on Shr. Equity	*12.0%*
	15.3%	14.3%	14.7%	15.0%	11.6%	9.2%	10.4%	11.2%	15.2%	11.7%	*9.5%*	*10.5%*	Return on Com Equity E	*12.0%*
	8.1%	7.6%	7.6%	8.4%	5.2%	3.0%	4.4%	4.8%	7.7%	3.9%	*1.5%*	*3.0%*	Retained to Com Eq	*5.0%*
	48%	48%	49%	45%	56%	68%	58%	58%	50%	68%	*84%*	*70%*	All Div'ds to Net Prof	*58%*



CAPITAL STRUCTURE as of 12/31/17
Total Debt $16677 mill. **Due in 5 Yrs** $6367.2 mill.
LT Debt $14337 mill. **LT Interest** $659.5 mill.
Incl. $551.5 mill. of securitization bonds.
(LT interest earned: 2.3x)
Leases, Uncapitalized Annual rentals $80.4 mill.
Pension Assets-12/17 $6071.3 mill.
Oblig $7987.1 mill.
Pfd Stock $197.8 mill. **Pfd Div'd** $13.6 mill.
642,307 sh. 4.32%-7.5%, $100 par; 250,000 sh. 8.75%, all without sinking fund.
Common Stock 180,770,383 shs.
as of 1/31/18
MARKET CAP: $14 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+1.3	+.3	+.2
Avg. Indust. Use (MWH)	957	NA	NA
Avg. Indust. Revs. per KWH(¢)	5.55	5.09	NA
Capacity at Peak (Mw)	24504	NA	NA
Peak Load, Summer (Mw)	21730	21387	NA
Annual Load Factor (%)	61	NA	NA
% Change Customers (yr-end)	+1.0	+.8	+.6
Fixed Charge Cov. (%)	223	258	169

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	1.5%	- -	*-2.0%*
"Cash Flow"	5.5%	1.0%	*3.0%*
Earnings	1.5%	-2.5%	*5.0%*
Dividends	4.0%	1.0%	*2.0%*
Book Value	2.0%	-1.0%	*3.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	2920	2713	3371	2509	11513
2016	2610	2463	3125	2648	10846
2017	2588	2619	3243	2624	11074
2018	*2550*	*2550*	*3150*	*2550*	*10800*
2019	*2550*	*2550*	*3150*	*2550*	*10800*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.65	.83	1.90	1.43	5.81
2016	1.28	3.16	2.16	.28	6.88
2017	.46	2.27	2.21	.25	5.19
2018	*.80*	*1.30*	*1.35*	*.80*	*4.25*
2019	*1.00*	*1.55*	*1.65*	*1.00*	*5.20*

QUARTERLY DIVIDENDS PAID B ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.83	.83	.83	.83	3.32
2015	.83	.83	.83	.85	3.34
2016	.85	.85	.85	.87	3.42
2017	.87	.87	.87	.89	3.50
2018	.89				

BUSINESS: Entergy Corporation supplies electricity to 2.9 million customers through subsidiaries in Arkansas, Louisiana, Mississippi, Texas, and New Orleans (regulated separately from Louisiana). Distributes gas to 199,000 customers in Louisiana. Has a nonutility subsidiary that owns six nuclear units (two no longer operating). Electric revenue breakdown: residential, 36%; commercial, 27%; industrial, 28%; other, 9%. Generating sources: gas, 35%; nuclear, 31%; coal, 7%; purchased, 27%. Fuel costs: 31% of revenues. '17 reported depreciation rate: 3.0%. Has 13,500 employees. Chairman & CEO: Leo P. Denault. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Telephone: 504-576-4000. Internet: www.entergy.com.

Entergy's utilities have some significant capital projects in various stages of development. Entergy Louisiana is building two gas-fired plants: a 980-megawatt facility scheduled for completion next year at a cost of $869 million and a 994-mw plant scheduled for completion in 2020 at a cost of $872 million. Entergy Texas intends to construct a 993-mw plant scheduled for commercial operation in 2021 at a cost of $937 million. Finally, each of Entergy's regulatory jurisdictions has granted the utility permission to install an advanced metering system, which is expected to cost about $900 million.

These projects illustrate the healthy demand for electricity in the company's service area. Unlike many utilities, which are seeing little or no load growth, Entergy expects volume increases in a low single-digit range. Other strong points are the formula rate plans in a few states (Entergy Louisiana is trying to extend its plan), which provide the utility with annual rate relief.

The company is exiting the nonregulated power-generating business. Entergy plans to close its four nonutility nuclear units by 2022. This business has become less profitable as wholesale electricity prices have declined. These plants have also experienced cost increases and operating problems. Even so, the company expects this business' cash flow to be neutral to positive through 2022. Note that our earnings presentation *includes* all costs associated with these facilities, even though management excludes these from its definition of operating earnings.

Income tax items can make earnings more volatile from year to year. In 2017, a tax benefit lifted June-quarter share net by $2.07. On the other hand, the revaluation of deferred taxes (due to the new federal tax law) caused a nonrecurring charge of $2.91 a share in the fourth period. In 2018, Entergy expects to book a tax benefit (now estimated at $100 million) related to its nonutility subsidiary.

This stock has one of the highest dividend yields of any electric utility. This is about a percentage point above the industry average. However, total return potential to 2021-2023 does not stand out among utilities.

Paul E. Debbas, CFA *March 16, 2018*

(A) Diluted EPS. Excl. nonrec. gain (losses): '02, ($1.04); '03, 33¢; '05, (21¢); '12, ($1.26); '13, ($1.14); '14, (56¢); '15, ($6.99); '16, ($10.14); '17, ($2.91). Next earnings report due early May. **(B)** Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. **(C)** Incl. def'd charges. In '17: $30.76/sh. **(D)** In mill. **(E)** Rate base: Net original cost. Allowed ROE (blended): 9.95%; earned on avg. com. eq., '17: 5.1%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	10
Earnings Predictability	60

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FIRSTENERGY NYSE-FE

RECENT PRICE **33.24** | P/E RATIO **33.2** (Trailing: 16.1 Median: 15.0) | RELATIVE P/E RATIO **1.87** | DIV'D YLD **4.3%** | **VALUE LINE**

TIMELINESS **4** Lowered 5/4/18
SAFETY **3** Lowered 2/22/13
TECHNICAL **2** Raised 5/18/18
BETA .65 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+50%)	*14%*
Low	30	(-10%)	*3%*

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	1	0	0	0	0	0	0
Options	0	4	0	0	3	0	0	3	12
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	269	258	245
to Sell	228	229	200
Hld's(000)	388940	401521	375942

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	75.0	84.0	53.6	47.8	46.5	51.1	46.8	40.8	41.7	36.6	35.2	35.6						
Low:	57.8	41.2	35.3	33.6	36.1	40.4	31.3	30.0	28.9	29.3	27.9	29.3						

LEGENDS
0.72 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2021 | 2022 | 2023

% TOT. RETURN 4/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.3	9.5
3 yr.	9.5	25.8
5 yr.	-7.3	68.8

Percent shares traded

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
	40.83	37.31	37.76	36.35	36.03	42.00	44.70	41.70	43.76	38.87	36.57	35.60	35.74	35.48	32.92	31.49	*24.25*	*22.30*	Revenues per sh	*24.25*
	6.45	4.79	7.60	7.55	7.22	8.34	9.04	8.80	8.50	5.75	6.05	6.30	4.55	6.33	6.53	6.54	*3.45*	*4.30*	"Cash Flow" per sh	*5.25*
	2.54	1.47	2.77	2.84	3.82	4.22	4.38	3.32	3.25	1.88	2.13	2.97	.85	2.00	2.10	2.73	*1.00*	*2.15*	Earnings per sh [A]	*2.75*
	1.50	1.50	1.91	1.71	1.85	2.05	2.20	2.20	2.20	2.20	2.20	1.65	1.44	1.44	1.44	1.44	*1.44*	*1.44*	Div'd Decl'd per sh [B] ■	*1.60*
	3.35	2.60	2.57	3.66	4.12	5.36	9.47	7.23	6.44	5.45	7.09	6.90	8.42	6.83	6.93	6.38	*5.85*	*4.65*	Cap'l Spending per sh	*5.00*
	23.92	25.13	26.04	27.86	28.30	29.45	27.17	28.08	28.03	31.75	31.29	30.32	29.49	29.33	14.11	8.81	*12.30*	*14.80*	Book Value per sh [C]	*18.00*
	297.64	329.84	329.84	329.84	319.21	304.84	304.84	304.84	304.84	418.22	418.22	418.63	421.10	423.56	442.34	445.33	*478.00*	*540.00*	Common Shs Outst'g [D]	*548.00*
	13.0	22.5	14.1	16.1	14.2	15.6	15.6	13.0	11.7	22.4	21.1	13.1	NMF	17.0	15.9	11.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*14.5*
	.71	1.28	.74	.86	.77	.83	.94	.87	.74	1.41	1.34	.74	NMF	.86	.83	.57			Relative P/E Ratio	*.80*
	4.6%	4.5%	4.9%	3.7%	3.4%	3.1%	3.2%	5.1%	5.8%	5.2%	4.9%	4.3%	4.3%	4.2%	4.3%	4.6%			Avg Ann'l Div'd Yield	*4.0%*
	13627	12712	13339	16258	15294	14903	15049	15029	14562	14022	*11600*	*12000*	Revenues ($mill)	*13300*
	1342.0	1015.0	991.0	752.0	891.0	1245.0	356.0	844.0	892.0	1213.0	*865*	*1155*	Net Profit ($mill)	*1520*
	36.7%	19.6%	38.6%	41.3%	41.1%	36.1%	5.6%	35.7%	37.8%	37.2%	*28.0%*	*28.0%*	Income Tax Rate	*28.0%*
	3.9%	12.8%	16.6%	9.3%	8.1%	6.0%	33.1%	13.9%	11.5%	6.5%	*9.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
	52.4%	58.2%	59.5%	54.2%	53.7%	55.5%	60.7%	60.7%	74.5%	84.3%	*70.5%*	*69.5%*	Long-Term Debt Ratio	*67.0%*
	47.7%	41.8%	40.5%	45.8%	46.3%	44.5%	39.3%	39.3%	25.5%	15.7%	*23.0%*	*30.5%*	Common Equity Ratio	*33.0%*
	17383	20467	21124	28996	28263	28523	31596	31613	24433	25040	*25375*	*26400*	Total Capital ($mill)	*30300*
	17723	19164	19788	30337	32903	33252	35783	37214	29387	28879	*29875*	*31225*	Net Plant ($mill)	*35600*
	9.7%	6.9%	6.3%	4.0%	4.9%	6.0%	2.7%	4.3%	5.7%	7.0%	*5.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
	16.2%	11.9%	11.6%	5.7%	6.8%	9.8%	2.9%	6.8%	14.3%	30.9%	*8.0%*	*14.0%*	Return on Shr. Equity	*15.5%*
	16.2%	11.9%	11.6%	5.7%	6.8%	9.8%	2.9%	6.8%	14.3%	30.9%	*8.0%*	*14.0%*	Return on Com Equity [E]	*15.5%*
	8.1%	4.0%	3.8%	NMF	NMF	2.6%	NMF	1.9%	4.5%	14.6%	*NMF*	*5.0%*	Retained to Com Eq	*6.5%*
	50%	66%	68%	117%	103%	74%	NMF	72%	68%	53%	*NMF*	*67%*	All Div'ds to Net Prof	*58%*

CAPITAL STRUCTURE as of 3/31/18
Total Debt $19097 mill. **Due in 5 Yrs** $8359 mill.
LT Debt $16740 mill. **LT Interest** $787 mill.
Incl. $91 mill. capitalized leases.
(LT interest earned: 2.4x)
Leases, Uncapitalized Annual rentals $146 mill.

Pension Assets-12/17 $6704 mill.
Oblig $10167 mill.

Pfd Stock None

Common Stock 476,909,318 shs.

MARKET CAP: $16 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.8	+.3	-2.1
Avg. Indust. Use (MWH)	NMF	NMF	NMF
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+.5	+.5
Fixed Charge Cov. (%)	206	208	249

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-1.5%	-3.5%	*-5.0%*
"Cash Flow"	-1.5%	-1.0%	*-3.5%*
Earnings	-4.5%	-1.0%	*3.0%*
Dividends	-2.5%	-8.0%	*2.0%*
Book Value	-5.0%	-10.5%	*.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	3897	3468	4123	3541	15029
2016	3869	3401	3917	3375	14562
2017	3557	3309	3714	3442	14022
2018	2976	*2724*	*3100*	*2800*	*11600*
2019	*3100*	*2800*	*3200*	*2900*	*12000*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.53	.46	.95	.06	2.00
2016	.77	.34	.89	.10	2.10
2017	.71	.59	.95	.49	2.73
2018	.04	*d.04*	*.55*	*.45*	*1.00*
2019	*.60*	*.45*	*.70*	*.40*	*2.15*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.36	.36	.36	.36	1.44
2015	.36	.36	.36	.36	1.44
2016	.36	.36	.36	.36	1.44
2017	.36	.36	.36	.36	1.44
2018	.36				

BUSINESS: FirstEnergy Corp. is a holding company for Ohio Edison, Pennsylvania Power, Cleveland Electric, Toledo Edison, Metropolitan Edison, Penelec, Jersey Central Power & Light, West Penn Power, Potomac Edison, & Mon Power. Provides electric service to 6.1 million customers in OH, PA, NJ, WV, MD, & NY. Acq'd Allegheny Energy 2/11. Electric revenue breakdown by customer class not available. Generating sources: coal, 44%; nuclear, 26%; purchased, 30%. Fuel costs: 33% of revenues. '17 reported deprec. rate: 2.4%. Has 15,700 employees. Chairman: George M. Smart. President & CEO: Charles E. Jones. Incorporated: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Telephone: 800-736-3402. Internet: www.firstenergycorp.com.

FirstEnergy has deconsolidated almost all of its nonregulated operations. These filed for Chapter 11 bankruptcy protection, and are now separate from FirstEnergy. Thus, its financial statements now reflect an almost entirely regulated company. The move resulted in a gain of $2.50 a share from discontinued operations in the first quarter of 2018.

The stock has been the top performer among electric utility issues so far in 2018. The price is up 9% in what has been a poor year for most equities in this industry. The market reacted favorably to the financing moves the company made in January, when it issued $850 million of common stock and $1.62 billion of preferred that is mandatorily convertible in 2019. The proceeds were used to reduce debt and contribute to the pension plan.

Our 2018 earnings estimate requires an explanation. The preferred stock that FirstEnergy issued in early 2018 was sold at a discount, and the difference is being amortized until the shares become convertible. This is why earnings were negligible in the first quarter, and might well fall into the red in the June period. Management's guidance for "operating" earnings this year is $2.25-$2.55 a share. Although earnings from continuing operations will almost certainly fall short of the dividend this year, the payout is not at risk of a cut.

The regulated businesses have some opportunities, but also a possible risk. The utilities in Ohio should soon receive a ruling from the state commission regarding a proposed three-year, $450 million electric system modernization plan. The company plans to spend $800 million-$1.2 billion on transmission annually through 2021. However, the company incurred $355 million of storm-related costs in the March quarter, $230 million of which were expenses. Of that, $220 million was deferred for future recovery. However, Jersey Central Power & Light was criticized in New Jersey for its performance following the storms, so the possibility of a write-off of some storm costs cannot be ruled out.

The yield of this untimely stock is above the utility average. However, the board hasn't raised the payout since that was cut in 2014, and dividend growth prospects are not well defined.

Paul E. Debbas, CFA *May 18, 2018*

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	10
Earnings Predictability	40

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(A) Diluted EPS. Excl. nonrec. gain (losses): '11, 33¢; '12, (29¢); '13, ($2.07); '14, (17¢); '15, (63¢); '16, ($16.59); '17, ($6.61); gains from disc. ops.: '14, 20¢; '18, $2.50. '17 EPS don't sum due to rounding. Next egs. report due late July. **(B)** Div'ds paid early Mar., June, Sep. & Dec. 5 div'ds decl. in '04, 3 in '13. ■ Div'd reinv. plan avail. **(C)** Incl. intang. In '17: $12.71/sh. **(D)** In mill. **(E)** Rate base: Depr. orig. cost. Rates all'd on com. eq.: 9.75%-11.9%; earned on avg. com. eq., '17: 18.5%. Regul. Clim.: OH Above Avg.; PA, NJ Avg.; MD, WV Below Avg.

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GREAT PLAINS EN'GY NYSE-GXP

RECENT PRICE **29.70** | P/E RATIO **23.6** (Trailing:NMF Median: 17.0) | RELATIVE P/E RATIO **1.24** | DIV'D YLD **3.9%** | **VALUE LINE**

TIMELINESS — Suspended 7/21/17
SAFETY **3** Lowered 12/26/08
TECHNICAL — Suspended 7/21/17
BETA .70 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+35%)	*11%*
Low	25	(-15%)	*Nil*

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	0	0	2	0	0	2	0
to Sell	0	0	0	0	6	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	182	177	136
to Sell	177	166	159
Hld's(000)	213579	211734	188292

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
High:	33.4	29.3	20.5	19.9	22.1	22.8	24.9	29.5	30.3	32.7	34.7	32.4								
Low:	26.9	15.6	10.2	16.6	16.3	19.5	20.4	23.8	24.1	25.8	26.7	28.5								
	26.91	31.04	33.13	34.85	33.30	37.89	14.00	14.51	16.62	17.03	15.05	15.90	16.66	16.21	12.43	12.56	*12.75*	*15.30*	Revenues per sh	*20.00*
	4.40	4.69	4.75	4.54	3.86	4.24	3.09	3.27	4.12	3.51	3.45	4.01	4.01	3.98	3.35	2.10	*3.50*	*4.40*	"Cash Flow" per sh	*6.50*
	2.04	2.27	2.46	2.18	1.62	1.86	1.16	1.03	1.53	1.25	1.35	1.62	1.57	1.37	1.61	d.06	*1.25*	*1.50*	Earnings per sh A	*2.25*
	1.66	1.66	1.66	1.66	1.66	1.66	1.66	.83	.83	.84	.86	.88	.94	1.00	1.06	1.10	*1.14*	*1.22*	Div'd Decl'd per sh B ■	*1.45*
	1.91	2.19	2.66	4.49	6.05	6.15	8.86	6.49	4.76	3.40	4.01	4.42	5.10	4.42	2.86	2.69	*2.60*	*3.05*	Cap'l Spending per sh	*3.50*
	13.58	13.82	15.35	16.37	16.70	18.18	21.39	20.62	21.26	21.74	21.75	22.58	23.26	23.68	24.73	23.02	*23.10*	*22.10*	Book Value per sh C	*22.75*
	69.20	69.26	74.37	74.74	80.35	86.23	119.26	135.42	135.71	136.14	153.53	153.87	154.16	154.40	215.35	215.66	*216.00*	*186.50*	Common Shs Outst'g D	*158.00*
	11.1	12.2	12.6	14.0	18.3	16.3	20.5	16.0	12.1	16.1	15.5	14.2	16.5	19.4	18.0	NMF	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.5*
	.61	.70	.67	.75	.99	.87	1.23	1.07	.77	1.01	.99	.80	.87	.98	.94	NMF			Relative P/E Ratio	*.85*
	7.3%	6.0%	5.4%	5.5%	5.6%	5.5%	7.0%	5.0%	4.5%	4.1%	4.1%	3.8%	3.6%	3.8%	3.6%	3.6%			Avg Ann'l Div'd Yield	*4.3%*
	1670.1	1965.0	2255.5	2318.0	2309.9	2446.3	2568.2	2502.2	2676.0	2708.2	*2750*	*2850*	Revenues ($mill)	*3150*
	119.5	135.6	211.7	174.4	199.9	250.2	242.8	213.0	290.0	24.1	*265*	*305*	Net Profit ($mill)	*370*
	34.5%	25.0%	31.7%	32.7%	34.3%	34.0%	32.3%	36.7%	37.4%	NMF	*24.0%*	*24.0%*	Income Tax Rate	*24.0%*
	46.8%	57.0%	25.7%	3.9%	3.3%	10.4%	12.8%	4.5%	4.6%	55.6%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*2.0%*
	49.7%	53.2%	50.2%	47.8%	44.9%	50.0%	49.0%	50.3%	35.3%	40.0%	*39.5%*	*47.0%*	Long-Term Debt Ratio	*49.0%*
	49.6%	46.2%	49.2%	51.6%	54.4%	49.4%	50.4%	49.1%	55.9%	60.0%	*60.5%*	*53.0%*	Common Equity Ratio	*51.0%*
	5146.2	6044.5	5867.6	5741.2	6135.8	7029.1	7113.1	7440.6	9527.2	8277.4	*8275*	*7805*	Total Capital ($mill)	*7025*
	6081.3	6651.1	6892.3	7053.5	7402.1	7746.4	8279.6	8662.4	8956.7	9124.7	*9190*	*9245*	Net Plant ($mill)	*9125*
	3.5%	3.9%	5.3%	5.0%	5.0%	5.0%	4.7%	4.2%	3.9%	1.1%	*4.0%*	*5.0%*	Return on Total Cap'l	*6.5%*
	4.6%	4.8%	7.2%	5.8%	5.9%	7.1%	6.7%	5.8%	4.7%	.5%	*5.5%*	*7.5%*	Return on Shr. Equity	*10.5%*
	4.6%	4.8%	7.3%	5.8%	5.9%	7.2%	6.7%	5.8%	5.1%	NMF	*5.5%*	*7.5%*	Return on Com Equity E	*10.5%*
	NMF	.9%	3.4%	2.0%	2.2%	3.2%	2.7%	1.6%	1.8%	NMF	*.5%*	*1.5%*	Retained to Com Eq	*4.0%*
	NMF	81%	54%	66%	63%	55%	60%	73%	67%	NMF	*93%*	*81%*	All Div'ds to Net Prof	*62%*

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.9	10.1
3 yr.	22.4	24.2
5 yr.	60.7	76.2

Target Price Range 2021 | 2022 | 2023

CAPITAL STRUCTURE as of 12/31/17
Total Debt $4231.5 mill. **Due in 5 Yrs** $2040.6 mill.
LT Debt $3312.6 mill. **LT Interest** $157.4 mill.
(LT interest earned: 1.8x)

Leases, Uncapitalized Annual rentals $12.9 mill.

Pension Assets-12/17 $848.4 mill.
Oblig $1355.9 mill.

Pfd Stock None

Common Stock 215,665,193 shs.
as of 2/16/18
MARKET CAP: $6.4 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-1.9	+.7	-1.6
Avg. Indust. Use (MWH)	1450	1500	1479
Avg. Indust. Revs. per KWH (¢)	6.96	7.29	7.68
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+.9	+1.1	+1.3
Fixed Charge Cov. (%)	254	307	162

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-9.0%	-3.5%	*6.5%*
"Cash Flow"	-3.0%	-3.0%	*NMF*
Earnings	-6.5%	-6.5%	*NMF*
Dividends	-4.5%	4.5%	*5.5%*
Book Value	3.5%	2.0%	*-1.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	549.1	609.0	781.4	562.7	2502.2
2016	572.1	670.8	856.8	576.3	2676.0
2017	570.7	682.6	857.2	597.7	2708.2
2018	*575*	*700*	*875*	*600*	*2750*
2019	*600*	*725*	*900*	*625*	*2850*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.12	.28	.82	.15	1.37
2016	.17	.20	.86	.39	1.61
2017	d.11	d.10	.02	.14	d.06
2018	*.08*	*.20*	*.84*	*.13*	*1.25*
2019	*.15*	*.25*	*.90*	*.20*	*1.50*

QUARTERLY DIVIDENDS PAID B ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.23	.23	.23	.245	.94
2015	.245	.245	.245	.2625	1.00
2016	.2625	.2625	.2625	.275	1.06
2017	.275	.275	.275	.275	1.10
2018	.275				

BUSINESS: Great Plains Energy Incorporated is a holding company for Kansas City Power & Light and two other subsidiaries, which supply electricity to 867,000 customers in western Missouri (71% of revenues) and eastern Kansas (29%). Acquired Aquila 7/08. Sold Strategic Energy (energy-marketing subsidiary) in '08. Electric revenue breakdown: residential, 40%; commercial, 41%; industrial, 9%; other, 10%. Generating sources: coal, 53%; nuclear, 16%; other, 2%; purchased, 29%. Fuel costs: 22% of revenues. '17 reported depreciation rate (utility): 3.0%. Has 2,700 employees. Chairman, President & CEO: Terry Bassham. Incorporated: Missouri. Address: 1200 Main St., Kansas City, Missouri 64105. Telephone: 816-556-2200. Internet: www.greatplainsenergy.com.

The proposed merger of Great Plains Energy and Westar Energy has made some progress. The deal calls for Great Plains stockholders to receive .5981 of a share of the combined company for each Great Plains share in a tax-free exchange. Shareholders and the Federal Energy Regulatory Commission have approved the transaction, and the companies have reached a settlement with the staffs of the Missouri and Kansas commissions. The regulators in each state must still rule on the merger. The companies expect the deal to be completed by mid-2018.

We think stockholders ought to retain their shares. The utilities of Great Plains and Westar are contiguous, and offer ample opportunities for merger-related cost reductions. The new company would aim to produce annual earnings growth of 6%-8% and a payout ratio of 60%-70%. The Timeliness rank of this stock remains suspended due to the pending merger.

The company's 2017 tally does not reflect its earning power. The red ink stemmed from merger-related expenses and the financing costs Great Plains incurred in anticipation of completing its original deal to acquire Westar. That transaction fell through when it failed to receive the approval of the Kansas commission (due in part to the debt needed to complete the purchase). As a result, the company incurred additional expenses as it unwound these financing moves. To top it all off, unfavorable weather conditions hurt the bottom line by $0.19 a share. Our estimates and projections are based on Great Plains as a stand-alone entity, and will include the merger-related costs that the company will book this year. The company expects to repurchase 60 million shares over a two-year span, and this is reflected in our figures.

Rate cases are pending in Missouri, and a filing in Kansas is expected in the next few weeks. Kansas City Power & Light and the Greater Missouri Operations asked for a total of $7.5 million (reflecting the pass-through of $67 million of federal taxes), based on a 9.85% return on equity. Orders are expected by late 2018. Similarly, KCP&L plans to file a petition in Kansas, with the same time frame for a regulatory decision.

Paul E. Debbas, CFA *March 16, 2018*

(A) Diluted earnings. Excl. nonrec. gains (losses): '02, (5¢); '03, 29¢; '04, (7¢); '09, 12¢; '17, (61¢); gain (losses) on disc. ops.: '03, (13¢); '04, 10¢; '05, (3¢); '08, 35¢. '16 & '17 EPS don't sum due to rounding. Next egs. report due early May. **(B)** Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. **(C)** Incl. intang. In '17: $5.02/sh. **(D)** In mill. **(E)** Rate base: Fair value. Rate all'd on com. eq. in MO in '17: 9.5%; in KS in '15: 9.3%; earned on avg. com. eq., '17: NMF. Reg. Climate: MO, Below Avg.; KS, Avg.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	25
Earnings Predictability	45

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HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE **34.92** | P/E RATIO **19.0** (Trailing: 21.3 / Median: 18.0) | RELATIVE P/E RATIO **1.01** | DIV'D YLD **3.6%** | **VALUE LINE**

TIMELINESS **3** Raised 2/23/18
SAFETY **2** Raised 11/2/12
TECHNICAL **3** Raised 4/27/18
BETA .65 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(Nil)	4%
Low	25	(-30%)	-3%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	8	0	0	0	0	0	0	4
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	123	112	117
to Sell	103	101	79
Hld's(000)	60992	61939	52290

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	27.5	29.8	22.7	25.0	26.8	29.2	28.3	35.0	34.9	35.0	38.7	36.2						
Low:	20.3	21.0	12.1	18.6	20.6	23.7	23.8	22.7	27.0	27.3	31.7	31.7						

LEGENDS
0.61 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2021 | 2022 | 2023

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.1	9.7
3 yr.	20.4	24.3
5 yr.	53.2	68.8

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
22.46	23.49	23.85	27.36	30.21	30.40	35.56	24.96	28.14	33.76	34.46	31.98	31.59	24.22	21.92	23.49	*24.35*	*25.00*	Revenues per sh	*27.00*
3.52	3.54	3.09	3.22	3.19	3.01	2.72	2.59	2.88	3.18	3.28	3.22	3.41	3.31	4.17	3.68	*4.00*	*4.15*	"Cash Flow" per sh	*4.75*
1.62	1.58	1.36	1.46	1.33	1.11	1.07	.91	1.21	1.44	1.67	1.62	1.64	1.50	2.29	1.64	*1.90*	*2.00*	Earnings per sh A	*2.25*
1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	*1.24*	*1.24*	Div'd Decl'd per sh B ■	*1.40*
1.74	2.15	2.66	2.76	2.58	2.62	3.12	3.29	1.92	2.45	3.32	3.49	3.31	3.39	3.04	4.55	*4.15*	*3.85*	Cap'l Spending per sh	*4.50*
14.21	14.36	15.01	15.02	13.44	15.29	15.35	15.58	15.67	15.95	16.28	17.06	17.47	17.94	19.03	19.28	*19.95*	*20.80*	Book Value per sh C	*23.75*
73.62	75.84	80.69	80.98	81.46	83.43	90.52	92.52	94.69	96.04	97.93	101.26	102.57	107.46	108.58	108.79	*108.80*	*110.00*	Common Shs Outst'g D	*113.00*
13.5	13.8	19.2	18.3	20.3	21.6	23.2	19.8	18.6	17.1	15.8	16.2	15.9	20.4	13.6	20.7	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.0*
.74	.79	1.01	.97	1.10	1.15	1.40	1.32	1.18	1.07	1.01	.91	.84	1.03	.71	1.04			Relative P/E Ratio	*.70*
5.7%	5.7%	4.8%	4.6%	4.6%	5.2%	5.0%	6.9%	5.5%	5.0%	4.7%	4.7%	4.8%	4.1%	4.0%	3.7%			Avg Ann'l Div'd Yield	*4.7%*
3218.9	2309.6	2665.0	3242.3	3375.0	3238.5	3239.5	2603.0	2380.7	2555.6	*2650*	*2750*	Revenues ($mill)	*3050*
92.2	84.9	115.4	140.1	164.9	163.4	170.2	161.8	250.1	180.6	*210*	*220*	Net Profit ($mill)	*270*
34.7%	34.1%	37.0%	35.1%	35.9%	34.0%	35.0%	36.5%	33.1%	34.7%	*22.0%*	*22.0%*	Income Tax Rate	*22.0%*
14.2%	20.6%	7.4%	6.0%	6.9%	4.8%	5.5%	5.8%	4.6%	9.6%	*7.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
46.0%	48.0%	44.5%	44.9%	45.7%	44.0%	45.2%	43.5%	41.6%	43.4%	*44.5%*	*45.5%*	Long-Term Debt Ratio	*44.0%*
52.7%	50.7%	54.3%	53.9%	53.1%	55.0%	53.8%	55.5%	57.5%	55.7%	*54.5%*	*53.5%*	Common Equity Ratio	*55.5%*
2635.2	2840.8	2732.9	2841.3	3001.0	3142.9	3332.3	3473.5	3595.1	3765.5	*3985*	*4260*	Total Capital ($mill)	*4875*
2907.4	3088.6	3165.9	3334.5	3594.8	3858.9	4148.8	4377.7	4603.5	5025.9	*5205*	*5390*	Net Plant ($mill)	*6025*
4.7%	4.3%	5.6%	6.2%	6.7%	6.4%	6.2%	5.7%	7.9%	5.8%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
6.5%	5.8%	7.6%	8.9%	10.1%	9.3%	9.3%	8.2%	11.9%	8.5%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.0%*
6.5%	5.8%	7.7%	9.0%	10.2%	9.4%	9.4%	8.3%	12.0%	8.5%	*9.5%*	*9.5%*	Return on Com Equity E	*10.0%*
.5%	NMF	1.4%	2.1%	4.2%	3.7%	2.3%	1.5%	6.3%	2.1%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
93%	116%	82%	78%	59%	61%	75%	83%	48%	76%	*66%*	*62%*	All Div'ds to Net Prof F	*59%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $1805.8 mill. **Due in 5 Yrs** $536.0 mill.
LT Debt $1633.8 mill. **LT Interest** $76.0 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 4.5x)
Leases, Uncapitalized Annual rentals $11.0 mill.
Pension Assets-12/17 $1618.7 mill.
Oblig $2094.4 mill.
Pfd Stock $34.3 mill. **Pfd Div'd** $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100.
Sinking fund ends 2018.
Common Stock 108,841,157 shs. **as of 2/13/18**
MARKET CAP: $3.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.2	-1.3	-1.8
Avg. Indust. Use (MWH)	5630	5350	5193
Avg. Indust. Revs. per KWH (¢)	22.71	20.28	22.56
Capacity at Yearend (Mw)	2224	2220	2224
Peak Load, Winter (Mw)	1610	1593	1584
Annual Load Factor (%)	66.9	66.6	65.8
% Change Customers (yr-end)	+.5	+.5	+.4
Fixed Charge Cov. (%)	399	437	409

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-2.5%	-6.5%	*2.5%*
"Cash Flow"	1.5%	3.5%	*4.0%*
Earnings	3.5%	4.5%	*3.5%*
Dividends	- -	- -	*2.0%*
Book Value	2.5%	3.5%	*4.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	637.9	623.9	717.2	624.0	2603.0
2016	551.0	566.2	646.1	617.4	2380.7
2017	591.5	632.3	673.2	658.6	2555.6
2018	*650*	*650*	*700*	*650*	*2650*
2019	*675*	*675*	*725*	*675*	*2750*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.31	.33	.47	.39	1.50
2016	.30	.41	1.17	.41	2.29
2017	.31	.36	.55	.42	1.64
2018	*.37*	*.43*	*.62*	*.48*	*1.90*
2019	*.40*	*.45*	*.65*	*.50*	*2.00*

QUARTERLY DIVIDENDS PAID B ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.31	.31	.31	.31	1.24
2015	.31	.31	.31	.31	1.24
2016	.31	.31	.31	.31	1.24
2017	.31	.31	.31	.31	1.24
2018	.31				

BUSINESS: Hawaiian Electric Industries, Inc. is the parent company of Hawaiian Electric Company, Inc. (HECO), American Savings Bank (ASB), and Pacific Current. HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 462,000 customers on O'ahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Elec. rev. breakdown: residential, 31%; commercial, 34%; lg. light & power, 34%; other, 1%. Generating sources: oil, 53%; purch., 47%. Fuel costs: 46% of revs. '17 reported depr. rate (util.): 3.2%. Has 3,900 employees. Chairman: Jeffrey N. Watanabe. Pres. & CEO: Constance H. Lau. Inc.: HI. Address: 1001 Bishop St., Suite 2900, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Web: www.hei.com.

Hawaiian Electric Industries' earnings are likely to rise sharply this year. The company's largest utility subsidiary, Hawaiian Electric Company (HECO), is benefiting from an interim rate increase that took effect in mid-February. Maui Electric Company (MECO) should obtain a partial year of interim rate relief from its pending rate case (see below). American Savings Bank will retain the benefits of the new federal tax law. We have raised our 2018 earnings estimate by $0.10 a share, to $1.90. Our revised forecast is at the midpoint of HEI's targeted range of $1.80-$2.00.

We expect further profit growth in 2019. HECO and MECO will have a full year's effect of the interim tariff hikes from 2018. We expect continued growth from ASB, as well.

MECO has a rate case pending. The utility filed for a rate increase of $30.1 million (9.3%), based on a return of 10.6% on a common-equity ratio of 56.9%. An interim rate order is expected in late August. This is MECO's first rate application in six years, and is a step toward HEI's goal of reducing its utilities' gap between their allowed and earned ROEs. Note that the $30.1 million figure does not reflect the effects of the new federal tax law.

ASB is performing well. The bank's interest-rate spread and return on assets are improving. A favorable external environment helps. Interest rates are rising, and the state's economy is healthy. ASB has also expanded its consumer lending, which has higher interest rates.

A new subsidiary should make a small contribution to earnings this year. Pacific Current owns a 60-megawatt power plant, which sells electricity to Hawaii Electric Light Company under a long-term agreement, and was awarded a contract for solar power and battery storage at five college campuses. This subsidiary is expected to provide $0.03 a share to profits in 2018.

We do not recommend this stock. The subpar regulatory climate and lack of near-term dividend growth potential are negative factors. With the recent quotation near the upper end of our 2021-2023 Target Price Range, total return potential is minimal.

Paul E. Debbas, CFA *April 27, 2018*

(A) Dil. EPS. Excl. gain (losses) from disc. ops.: '03, (5¢); '04, 2¢; '05, (1¢); nonrec. gain (losses): '05, 11¢; '07, (9¢); '12, (25¢); '17, (12¢). Next earnings report due early May.
(B) Div'ds paid in early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. **(C)** Incl. intang. In '17: $7.93/sh. **(D)** In mill., adj. for split. **(E)** Rate base: Orig. cost. Rate allowed on com. eq. in '11: HECO, 10%; in '12: HELCO, 10%; in '13: MECO, 9%; earn. on avg. com. eq., '17: 8.6%. Regulat. Climate: Below Avg. **(F)** Excl. div'ds paid through reinvest. plan.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	20
Earnings Predictability	60

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IDACORP, INC. NYSE-IDA

RECENT PRICE **88.84** | P/E RATIO **21.1** (Trailing: 21.1 Median: 14.0) | RELATIVE P/E RATIO **1.12** | DIV'D YLD **2.7%** | **VALUE LINE**

TIMELINESS **2** Raised 12/22/17
SAFETY **2** Raised 8/2/13
TECHNICAL **3** Lowered 2/23/18
BETA .70 (1.00 = Market)

2021-23 PROJECTIONS

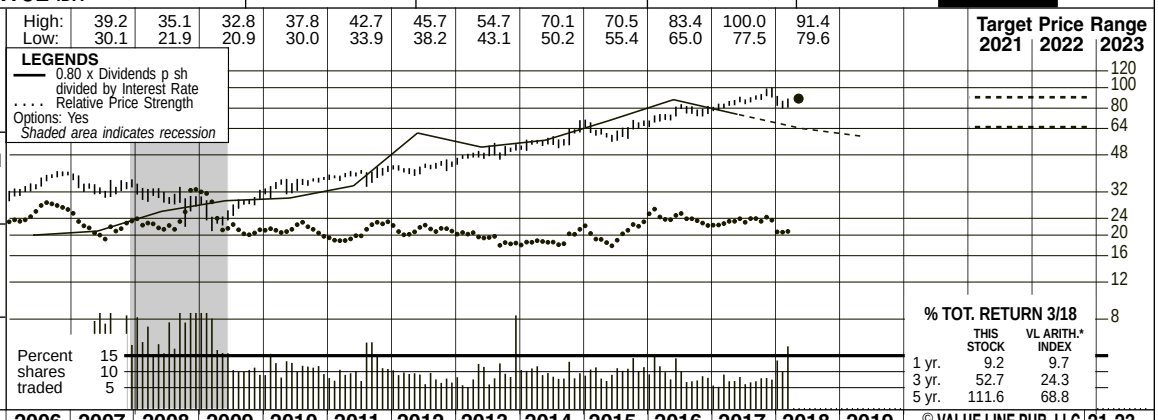
	Price	Gain	Ann'l Total Return
High	90	(Nil)	3%
Low	65	(-25%)	-4%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	10
to Sell	2	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	139	116	127
to Sell	91	113	86
Hld's(000)	45985	45708	38200



2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.23	25.04	26.76	*26.60*	*27.00*	Revenues per sh	*28.75*
4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.35	5.84	5.93	6.29	6.58	6.70	6.86	7.50	*7.65*	*8.05*	"Cash Flow" per sh	*9.25*
1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.87	3.94	4.21	*4.15*	*4.35*	Earnings per sh [A]	*4.75*
1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	2.08	2.24	*2.40*	*2.56*	Div'd Decl'd per sh [B] ■ †	*3.05*
3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	5.84	5.89	5.66	*6.25*	*6.40*	Cap'l Spending per sh	*6.75*
23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	40.88	42.74	44.65	*46.40*	*48.15*	Book Value per sh [C]	*53.25*
38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.34	50.40	50.42	*50.40*	*50.40*	Common Shs Outst'g [D]	*50.40*
18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	16.2	19.1	20.6	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.0*
1.03	1.51	.82	.89	.82	.97	.84	.68	.75	.72	.79	.75	.77	.82	1.00	1.04			Relative P/E Ratio	*.90*
6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%	2.8%	2.6%			Avg Ann'l Div'd Yield	*4.0%*
960.4	1049.8	1036.0	1026.8	1080.7	1246.2	1282.5	1270.3	1262.0	1349.5	*1340*	*1360*	Revenues ($mill)	*1450*
98.4	124.4	142.5	166.9	168.9	182.4	193.5	194.7	198.3	212.4	*210*	*220*	Net Profit ($mill)	*245*
16.3%	15.2%	--	--	13.4%	28.3%	8.0%	19.0%	15.5%	18.6%	*10.5%*	*10.5%*	Income Tax Rate	*10.5%*
10.2%	10.5%	19.1%	23.3%	20.3%	12.3%	13.6%	16.3%	16.3%	13.9%	*14.0%*	*14.0%*	AFUDC % to Net Profit	*14.0%*
47.6%	50.2%	49.3%	45.6%	45.5%	46.6%	45.3%	45.6%	44.8%	43.7%	*44.0%*	*42.0%*	Long-Term Debt Ratio	*44.0%*
52.4%	49.8%	50.7%	54.4%	54.5%	53.4%	54.7%	54.4%	55.2%	56.3%	*56.0%*	*58.0%*	Common Equity Ratio	*56.0%*
2485.9	2807.1	3020.4	3045.2	3225.4	3465.9	3567.6	3783.3	3898.5	3997.5	*4180*	*4165*	Total Capital ($mill)	*4775*
2758.2	2917.0	3161.4	3406.6	3536.0	3665.0	3833.5	3992.4	4172.0	4283.9	*4425*	*4560*	Net Plant ($mill)	*4850*
5.3%	5.7%	6.0%	6.8%	6.5%	6.4%	6.6%	6.2%	6.1%	6.3%	*6.0%*	*6.5%*	Return on Total Cap'l	*6.0%*
7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	*9.0%*	*9.0%*	Return on Com Equity [E]	*9.0%*
3.4%	4.8%	5.5%	6.5%	5.7%	5.6%	5.4%	4.8%	4.3%	4.4%	*4.0%*	*4.0%*	Retained to Com Eq	*3.5%*
55%	46%	41%	36%	41%	43%	46%	50%	53%	53%	*57%*	*59%*	All Div'ds to Net Prof	*63%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $1746.1 mill. **Due in 5 Yrs** $305.0 mill.
LT Debt $1746.1 mill. **LT Interest** $82.0 mill.
(LT interest earned: 3.9x)

Pension Assets-12/17 $697.7 mill.
Oblig $999.3 mill.

Pfd Stock None

Common Stock 50,392,360 shs.
as of 2/16/18

MARKET CAP: $4.5 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+1.2	-.5	+2.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.70	5.63	5.83
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3402	3299	3422
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.4	+1.8	+2.0
Fixed Charge Cov. (%)	307	295	329

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	2.5%	4.0%	*2.0%*
"Cash Flow"	5.5%	4.0%	*4.5%*
Earnings	7.5%	4.5%	*3.5%*
Dividends	5.5%	10.5%	*6.5%*
Book Value	5.5%	5.5%	*3.5%*

QUARTERLY REVENUES($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	279.4	336.3	369.2	285.4	1270.3
2016	281.0	315.4	372.0	293.6	1262.0
2017	302.6	333.0	408.3	305.6	1349.5
2018	*310*	*335*	*390*	*305*	*1340*
2019	*315*	*340*	*395*	*310*	*1360*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.47	1.31	1.46	.63	3.87
2016	.51	1.12	1.65	.66	3.94
2017	.66	.99	1.80	.77	4.21
2018	*.60*	*1.00*	*1.85*	*.70*	*4.15*
2019	*.65*	*1.05*	*1.90*	*.75*	*4.35*

QUARTERLY DIVIDENDS PAID [B] ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.43	.43	.43	.47	1.76
2015	.47	.47	.47	.51	1.92
2016	.51	.51	.51	.55	2.08
2017	.55	.55	.55	.59	2.24
2018	.59				

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 545,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 41%; commercial, 24%; industrial, 14%; irrigation, 11%; other, 10%. Generating sources: hydro, 50%; coal, 18%; gas, 8%; purchased, 24%. Fuel costs: 33% of revenues. '17 reported depreciation rate: 2.9%. Has 2,000 employees. Chairman: Robert A. Tinstman. President & CEO: Darrel T. Anderson. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

IDACORP's 10-year streak of earnings growth might well come to an end in 2018. This is despite the performance of the company's utility subsidiary, Idaho Power, which is faring well, is financially sound, and has good growth prospects. A year ago, IDACORP's income benefited from some tax adjustments. Favorable weather conditions, helped, as well. Our earnings estimate of $4.15 a share, which we trimmed by a nickel, is within the company's targeted range of $4.10-$4.25. Given that IDACORP earned $4.21 a share in 2017, another year of profit growth is hardly out of the question, based on the company's guidance.

We expect dividend growth to continue, even if earnings growth is interrupted. Management anticipates recommending to the board annual increases of at least 5%. The company is targeting a payout ratio in a range of 50%-60%.

Idaho Power is performing well. The economy of the company's service area is healthy. Customer growth was 2.0% last year, which is more than double the industry norm. Kilowatt-hour sales generally aren't rising as fast (the 2.6% increase in 2017 was driven in part by weather) due to the effects of energy efficiency. The utility's cost control has been effective, too.

We forecast a resumption of profit growth in 2019. We think IDACORP will benefit from the growth of Idaho Power. Our $4.35-a-share estimate would produce an increase of 5%.

The utility has a regulatory mechanism to supplement its income, if necessary. If Idaho Power's earned return on equity falls below 9.5% through 2019, the utility may use up to $25 million of accumulated deferred investment tax credits annually to bring its ROE to that level. (A proposed regulatory settlement would extend this mechanism indefinitely beyond next year.) Note that the ROEs shown in the statistical array are for IDACORP as a whole, not just its utility subsidiary.

This stock is timely, but is priced expensively. The dividend yield is below average for a utility. The recent quotation is near the upper end of our 2021-2023 Target Price Range. Accordingly, total return potential is negligible.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. nonrecurring gains (loss): '03, 26¢; '05, (24¢); '06, 17¢. '17 earnings don't sum due to rounding. Next earnings report due early May. **(B)** Div'ds historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan available. **(C)** Incl. intangibles. In '17: $21.49/sh. **(D)** In millions. **(E)** Rate base: Net original cost. Rate allowed on common equity in '11: 10% (imputed); earned on avg. com. eq., '17: 9.6%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	95

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MGE ENERGY INC. NDQ-MGEE

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
53.90	23.5 (Trailing: 19.1 Median: 17.0)	1.23	2.5%	

TIMELINESS 3 Raised 3/9/18
SAFETY 1 New 1/3/03
TECHNICAL 3 Lowered 3/2/18
BETA .70 (1.00 = Market)

2021-23 PROJECTIONS

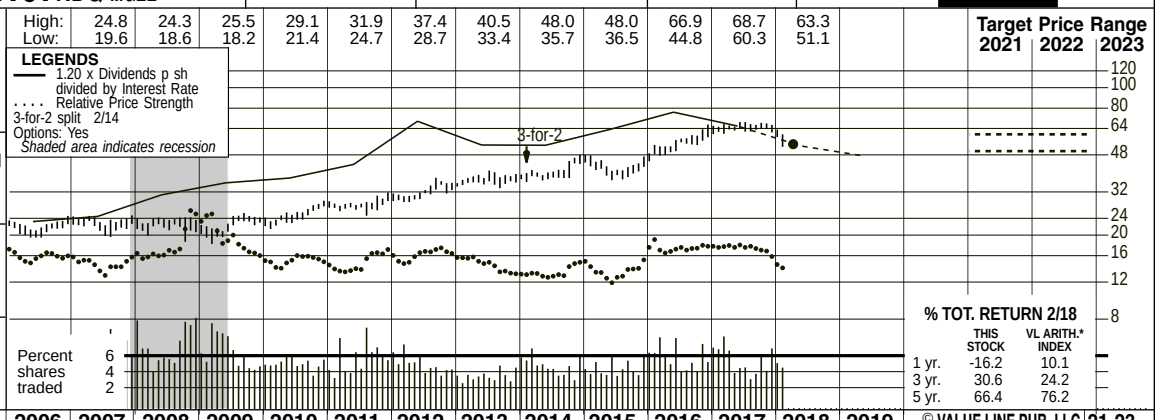
	Price	Gain	Ann'l Total Return
High	60	(+10%)	5%
Low	50	(-5%)	1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	1	0	0	1	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	69	57	53
to Sell	58	63	50
Hld's(000)	15201	15468	13520



	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
High:	24.8	24.3	25.5	29.1	31.9	37.4	40.5	48.0	48.0	66.9	68.7	63.3								
Low:	19.6	18.6	18.2	21.4	24.7	28.7	33.4	35.7	36.5	44.8	60.3	51.1								
	13.17	14.59	13.89	16.73	16.13	16.33	17.35	15.40	15.36	15.76	15.61	17.04	17.88	16.27	15.71	16.24	*17.15*	*18.30*	Revenues per sh	*21.55*
	2.22	1.96	1.92	2.00	2.34	2.46	2.68	2.66	2.76	2.94	2.98	3.28	3.49	3.33	3.47	3.73	*4.05*	*4.35*	"Cash Flow" per sh	*5.70*
	1.13	1.14	1.18	1.05	1.37	1.51	1.59	1.47	1.67	1.76	1.86	2.16	2.32	2.06	2.18	2.20	*2.35*	*2.50*	Earnings per sh A	*3.30*
	.89	.90	.91	.92	.93	.94	.96	.97	.99	1.01	1.04	1.07	1.11	1.16	1.21	1.26	*1.32*	*1.38*	Div'd Decl'd per sh B ■	*1.60*
	2.97	3.02	3.13	2.80	2.94	4.14	3.08	2.35	1.76	1.88	2.84	3.43	2.67	2.08	2.41	3.12	*2.85*	*3.15*	Cap'l Spending per sh	*3.75*
	8.62	9.56	11.06	11.21	11.93	12.99	13.92	14.47	15.14	15.89	16.71	17.81	19.02	19.92	20.89	22.45	*23.70*	*24.85*	Book Value per sh E	*32.65*
	26.36	27.52	30.59	30.68	31.46	32.93	34.36	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	34.67	*35.00*	*35.00*	Common Shs Outst'g C	*36.00*
	16.0	17.5	18.0	22.4	15.9	15.0	14.2	15.1	15.0	15.8	17.2	17.0	17.2	20.3	24.9	22.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.0*
	.87	1.00	.95	1.19	.86	.80	.85	1.01	.95	.99	1.09	.96	.91	1.02	1.31	1.12			Relative P/E Ratio	*.90*
	5.0%	4.5%	4.3%	3.9%	4.3%	4.1%	4.2%	4.4%	4.0%	3.6%	3.2%	2.9%	2.8%	2.8%	2.2%	2.0%			Avg Ann'l Div'd Yield	*3.0%*
							596.0	533.8	532.6	546.4	541.3	590.9	619.9	564.0	544.7	563.1	*600*	*640*	Revenues ($mill)	*775*
							52.8	51.0	57.7	60.9	64.4	74.9	80.3	71.3	75.6	76.1	*82.5*	*87.5*	Net Profit ($mill)	*120*
							35.5%	35.6%	36.9%	37.1%	37.7%	37.5%	37.5%	36.7%	36.0%	36.4%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
							- -	- -	- -	- -	- -	- -	- -	- -	2.2%	2.0%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
							36.3%	39.0%	38.9%	39.6%	38.2%	39.3%	37.5%	36.2%	34.6%	33.8%	*34.0%*	*34.0%*	Long-Term Debt Ratio	*32.0%*
							63.7%	61.0%	61.1%	60.4%	61.8%	60.7%	62.5%	63.8%	65.4%	66.2%	*66.0%*	*66.0%*	Common Equity Ratio	*68.0%*
							750.6	822.7	859.4	911.9	937.9	1016.9	1054.7	1081.5	1106.9	1176.3	*1255*	*1320*	Total Capital ($mill)	*1725*
							901.2	939.8	968.0	995.6	1073.5	1160.2	1208.1	1243.4	1282.1	1341.4	*1400*	*1460*	Net Plant ($mill)	*1650*
							7.7%	6.9%	7.6%	7.8%	7.9%	8.3%	8.5%	7.5%	7.7%	7.3%	*7.5%*	*7.5%*	Return on Total Cap'l	*7.5%*
							11.0%	10.2%	11.0%	11.1%	11.1%	12.1%	12.2%	10.3%	10.4%	9.8%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.0%*
							11.0%	10.2%	11.0%	11.1%	11.1%	12.1%	12.2%	10.3%	10.4%	9.8%	*10.0%*	*10.0%*	Return on Com Equity D	*10.0%*
							4.4%	3.4%	4.4%	4.7%	4.9%	6.1%	6.4%	4.5%	4.7%	4.2%	*4.5%*	*4.5%*	Retained to Com Eq	*5.5%*
							60%	66%	60%	57%	56%	50%	48%	56%	55%	57%	*56%*	*55%*	All Div'ds to Net Prof	*48%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $426.6 mill. **Due in 5 Yrs** $62.3 mill.
LT Debt $398.2 mill. **LT Interest** $20.0 mill.
(LT interest earned: 7.2x)

Leases, Uncapitalized Annual rentals $1.2 mill.
Pension Assets-12/17 $361.7 mill.
Obligation $391.3 mill.
Pfd Stock None

Common Stock 34,668,370 shs.
as of 2/1/18
MARKET CAP: $1.9 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-0.3	1.1	-2.6
Avg. Indust. Use (MWH)	2484	2329	1966
Avg. Indust. Revs. per KWH (¢)	8.17	7.55	8.23
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	783	783	783
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	616	645	666

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	- -	.5%	*5.0%*
"Cash Flow"	5.0%	5.0%	*7.5%*
Earnings	6.0%	6.0%	*6.0%*
Dividends	2.5%	3.5%	*5.0%*
Book Value	6.0%	6.0%	*7.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	170.1	122.1	140.8	131.0	564.0
2016	147.5	121.6	136.7	138.9	544.7
2017	156.8	126.5	139.5	140.3	563.1
2018	*165*	*135*	*148*	*152*	*600*
2019	*175*	*145*	*158*	*162*	*640*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.53	.39	.82	.32	2.06
2016	.49	.47	.80	.42	2.18
2017	.56	.45	.77	.42	2.20
2018	*.58*	*.48*	*.81*	*.48*	*2.35*
2019	*.62*	*.52*	*.84*	*.52*	*2.50*

QUARTERLY DIVIDENDS PAID B ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.2717	.2717	.2825	.2825	1.11
2015	.2825	.2825	.2950	.2950	1.16
2016	.2950	.2950	.3075	.3075	1.21
2017	.3075	.3075	.3225	.3225	1.26
2018	.3225				

BUSINESS: MGE Energy, Inc. is a holding company for Madison Gas and Electric. It provides electric service to about 151,000 customers in Dane County and gas service to 158,000 customers in seven counties in Wisconsin. Electric revenue breakdown, '17: residential, 34%; commercial, 53%; industrial, 4%; public authorities, 9%. Generating sources, '17: coal, 53%; purchased power, 24%; natural gas and other, 23%. Fuel costs: 20% of rev. '17 depr. rate: 4.0%. Has 712 employees. Off. and dir. own less than 1% of common; The Vanguard Group, Inc., 9.2%; BlackRock, Inc., 6.3% (3/17 proxy). Chairman: Gary J. Wolter. Pres. & CEO: Jeffrey M. Keebler. Inc.: WI. Addr.: 133 South Blair St., Madison, WI 53788. Tel.: 608-252-7000. Web: www.mgeenergy.com.

Shares of MGE Energy have traded lower over the past three months. We believe the stock was particularly vulnerable due to its rich valuation. At the time of our December review, the equity had traded at a price-to-earnings multiple that was well in excess of its historical average. The company posted modest top-line growth for the December quarter. Share earnings of $0.42 matched the prior-year tally. Subscribers are advised that our bottom-line presentation excludes a nonrecurring tax benefit of $0.62 a share related to the U.S. Tax Cuts and Jobs Act.

Prospects for the coming years appear fairly bright. The company's utility operations should be able to capitalize on favorable demographics within its service territories. Healthy residential customer growth will probably further benefit performance here. Investment in operations should also pay off down the road. This includes the construction of a wind farm near Saratoga, Iowa. The 66-megawatt site would consist of 33 turbines. This project is expected to be completed by the end of the year at a cost of $108 million. MGE has also agreed to purchase a stake in the Forward Wind Energy Center. Assuming regulatory approval, this acquisition would provide access to renewable energy for an additional 15 years. Transmission investments and the expansion of the company's solar program will likely also benefit performance. Moreover, efforts by MGE to control operating expenses ought to bear fruit. All things considered, we anticipate healthy growth in revenues and earnings per share from 2018 onward.

This equity is neutrally ranked for year-ahead relative price performance. The shares do not stand out for long-term total return potential, either. The valuation remains on the high side, despite the aforementioned selloff. The dividend yield has improved somewhat over the past three months, though it is not particularly attractive for a utility. The risk profile does appear to be favorable here. MGE Energy earns good marks for Safety, Financial Strength, Price Stability, and Earnings Predictability. Volatility is subdued, as well. Nevertheless, investors can probably find better choices elsewhere at this time.

Michael Napoli, CFA *March 16, 2018*

(A) Diluted earnings. Excludes nonrecurring: '17, 62¢. Next earnings report due early May. **(B)** Dividends historically paid in mid-March, June, September, and December. ■ Div'd. reinvestment plan available. **(C)** In millions, adjusted for split. **(D)** Rate allowed on common equity in '17: 9.8%; earned on common equity, '17: 12.5%. Regulatory Climate: Above Average. **(E)** Includes regulatory assets. In 2017: $150.5 mill., $4.34 per share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	65
Earnings Predictability	90

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NEXTERA ENERGY NYSE-NEE

RECENT PRICE **159.91** | P/E RATIO **20.6** (Trailing: 23.9 / Median: 16.0) | RELATIVE P/E RATIO **1.16** | DIV'D YLD **2.9%** | **VALUE LINE**

TIMELINESS 3 Lowered 3/9/18
SAFETY 1 Raised 2/16/18
TECHNICAL 2 Raised 5/18/18
BETA .65 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	195	(+20%)	*8%*
Low	160	(Nil)	*4%*

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	1	0	23	0
to Sell	0	1	2	1	1	1	0	3	4

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	520	489	520
to Sell	507	534	493
Hld's(000)	394716	390847	358013

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
High:	72.8	73.8	60.6	56.3	61.2	72.2	89.8	110.8	112.6	132.0	159.4	165.1								
Low:	53.7	33.8	41.5	45.3	49.0	58.6	69.8	84.0	93.7	102.2	117.3	145.1								
	22.74	26.13	28.27	30.00	38.75	37.47	40.13	37.82	36.39	36.88	33.62	34.80	38.42	37.93	34.52	36.51	***34.60***	***33.65***	Revenues per sh	***38.25***
	4.51	5.36	5.60	6.18	6.77	6.85	8.03	8.75	9.62	9.29	8.69	10.54	12.10	12.92	12.97	12.11	***15.20***	***15.65***	"Cash Flow" per sh	***19.00***
	2.01	2.45	2.46	2.32	3.23	3.27	4.07	3.97	4.74	4.82	4.56	4.83	5.60	6.06	5.78	6.50	***7.75***	***8.30***	Earnings per sh [A]	***10.00***
	1.16	1.20	1.30	1.42	1.50	1.64	1.78	1.89	2.00	2.20	2.40	2.64	2.90	3.08	3.48	3.93	***4.44***	***5.00***	Div'd Decl'd per sh [B] ■ †	***6.60***
	3.44	3.75	3.75	4.09	9.22	12.32	12.80	14.52	13.89	15.93	22.31	15.36	15.84	18.17	20.59	22.80	***20.00***	***18.70***	Cap'l Spending per sh	***18.75***
	17.48	18.91	20.25	21.52	24.49	26.35	28.57	31.35	34.36	35.92	37.90	41.47	44.96	48.97	52.01	59.89	***68.90***	***70.45***	Book Value per sh [C]	***80.50***
	365.51	368.53	372.24	394.85	405.40	407.35	408.92	413.62	420.86	416.00	424.00	435.00	443.00	461.00	468.00	471.00	***500.00***	***535.00***	Common Shs Outst'g [D]	***535.00***
	14.2	12.6	13.6	17.9	13.7	18.9	14.5	13.4	10.8	11.5	14.4	16.6	17.3	16.9	20.7	21.6			Avg Ann'l P/E Ratio	***18.0***
	.78	.72	.72	.95	.74	1.00	.87	.89	.69	.72	.92	.93	.91	.85	1.09	1.08			Relative P/E Ratio	***1.00***
	4.1%	3.9%	3.9%	3.4%	3.4%	2.7%	3.0%	3.5%	3.9%	4.0%	3.6%	3.3%	3.0%	3.0%	2.9%	2.8%			Avg Ann'l Div'd Yield	***3.7%***
	16410	15643	15317	15341	14256	15136	17021	17486	16155	17195	***17300***	***18000***	Revenues ($mill)	***20500***
	1639.0	1615.0	1957.0	2021.0	1911.0	2062.0	2465.0	2752.0	2693.0	3074.0	***3895***	***4435***	Net Profit ($mill)	***5565***
	21.5%	16.8%	21.4%	22.4%	26.6%	26.9%	32.3%	30.8%	29.3%	24.4%	***24.5%***	***24.5%***	Income Tax Rate	***24.5%***
	6.6%	7.9%	4.4%	4.4%	10.8%	7.0%	6.7%	6.9%	8.2%	6.7%	***6.0%***	***5.0%***	AFUDC % to Net Profit	***4.0%***
	54.2%	55.7%	55.5%	58.2%	59.1%	57.1%	55.0%	54.2%	53.3%	52.7%	***46.5%***	***45.0%***	Long-Term Debt Ratio	***46.0%***
	45.8%	44.3%	44.5%	41.8%	40.9%	42.9%	45.0%	45.8%	46.7%	47.3%	***53.5%***	***55.0%***	Common Equity Ratio	***54.0%***
	25514	29267	32474	35753	39245	42009	44283	49255	52159	59671	***64100***	***68750***	Total Capital ($mill)	***79600***
	32411	36078	39075	42490	49413	52720	55705	61386	66912	72416	***78625***	***84600***	Net Plant ($mill)	***101200***
	7.9%	6.9%	7.4%	7.0%	6.2%	6.2%	7.0%	6.8%	6.3%	6.3%	***7.0%***	***7.5%***	Return on Total Cap'l	***8.0%***
	14.0%	12.5%	13.5%	13.5%	11.9%	11.4%	12.4%	12.2%	11.1%	10.9%	***11.5%***	***12.0%***	Return on Shr. Equity	***13.0%***
	14.0%	12.5%	13.5%	13.5%	11.9%	11.4%	12.4%	12.2%	11.1%	10.9%	***11.5%***	***12.0%***	Return on Com Equity [E]	***13.0%***
	7.9%	6.5%	7.8%	7.4%	5.6%	5.2%	6.0%	6.1%	4.4%	4.4%	***5.0%***	***4.5%***	Retained to Com Eq	***4.5%***
	44%	47%	42%	46%	53%	54%	51%	50%	60%	60%	***55%***	***58%***	All Div'ds to Net Prof	***63%***

Bold figures are Value Line estimates

CAPITAL STRUCTURE as of 3/31/18
Total Debt $32199 mill. **Due in 5 Yrs** $13816 mill.
LT Debt $28062 mill. **LT Interest** $1179 mill.

(LT interest earned: 3.9x)

Pension Assets-12/17 $4020 mill.
Oblig $2593 mill.

Pfd Stock None

Common Stock 471,436,476 shs.

MARKET CAP: $75 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+5.6	-.8	-.9
Avg. Indust. Use (MWH)	277	255	NA
Avg. Indust. Revs. per KWH (¢)	6.69	6.11	NA
Capacity at Peak (Mw)	26073	NA	NA
Peak Load, Summer (Mw)	22717	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.4	+1.3	NA
Fixed Charge Cov. (%)	348	339	278

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	.5%	.5%	*1.0%*
"Cash Flow"	6.5%	6.5%	*7.0%*
Earnings	7.5%	5.5%	*8.5%*
Dividends	8.5%	9.5%	*11.0%*
Book Value	8.5%	8.5%	*7.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	4104	4358	4954	4070	17486
2016	3835	3817	4805	3698	16155
2017	3972	4404	4808	4011	17195
2018	3863	***4337***	***5000***	***4100***	***17300***
2019	***4000***	***4600***	***5200***	***4200***	***18000***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.45	1.59	1.93	1.10	6.06
2016	1.41	.93	1.62	1.82	5.78
2017	1.90	1.68	1.79	1.13	6.50
2018	2.09	***1.81***	***2.20***	***1.65***	***7.75***
2019	***2.15***	***2.20***	***2.25***	***1.70***	***8.30***

QUARTERLY DIVIDENDS PAID [B] ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.725	.725	.725	.725	2.90
2015	.77	.77	.77	.77	3.08
2016	.87	.87	.87	.87	3.48
2017	.9825	.9825	.9825	.9825	3.93
2018	1.11				

BUSINESS: NextEra Energy, Inc. (formerly FPL Group, Inc.) is a holding company for Florida Power & Light Company (FPL), which provides electricity to 4.9 million customers in a 27,650-sq.-mi. area in eastern & southern Florida. NextEra Energy Resources is a non-regulated power generator with nuclear, gas, & wind ownership. Has a 79.9% stake in NextEra Energy Partners. Rev. breakdown: residential, 55%; commercial, 35%; industrial & other, 10%. Generating sources: gas, 71%; nuclear, 23%; coal, 4%; purchased, 2%. Fuel costs: 24% of revs. '17 reported depr. rate (utility): 3.7%. Has 13,900 employees. Chairman, President and CEO: James L. Robo. Inc.: Florida. Address: 700 Universe Blvd., Juno Beach, FL 33408. Tel.: 561-694-4000. Internet: www.nexteraenergy.com.

The utility and nonutility sides of NextEra Energy's business are each performing well. Florida Power & Light received a $211 million rate increase at the start of 2018, and will get additional rate relief in mid-2019 after a 1,750-mw gas-fired plant achieves commercial operation. Superior customer growth, helped by the healthy economy in the Sunshine State, is another positive factor. NextEra Energy Resources is adding renewable-energy projects and natural gas pipelines. Two pipeline projects were completed in 2017, and another is expected to begin operation by yearend. This subsidiary will also benefit from the reduced federal tax rate, which management expects will add $0.45 a share to corporate profits this year. All told, we estimate solid earnings growth in 2018 and 2019. Our estimates are within the company's targeted ranges of $7.45-$7.95 a share and $8.00-$8.50 a share, respectively. Note, however, that NextEra's guidance *excludes* gains or losses from mark-to-market accounting items, but we include these because they are ongoing. This boosted profits by $0.26 a share in the March quarter.

The company deconsolidated its NextEra Energy Partners (NEP) master limited partnership subsidiary. This happened due to changes in NEP's governance structure. NextEra recorded a nonrecurring, noncash gain of $6.26 a share in the first quarter due to the deconsolidation. The company also booked nonrecurring, noncash income of $0.96 a share in the same period, thanks to the effects of the new federal tax law.

NextEra Energy's board of directors extended the company's dividend policy through 2020. The expectation is for annual dividend growth of 12%-14% over this time frame. In the first quarter, the board raised the annual disbursement by $0.51 a share (13%).

This equity continues to be one of the top performers in this industry. This is in recognition of NextEra's good results and solid prospects. The price rose 31% last year, and is up slightly in 2018 — a year in which most stocks have lost value. Neither the dividend yield nor the 3- to 5-year total return potential stand out among utility issues, however.

Paul E. Debbas, CFA *May 18, 2018*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '02, (60¢); '03, 5¢; '11, (24¢); '13, (80¢); '16, 47¢; '17, 91¢; '18, $7.23; gain on disc. ops.: '13, 44¢. '15 EPS don't sum due to rounding. Next earnings report due late July. **(B)** Div'ds historically paid in mid-Mar., mid-June, mid-Sept., & mid-Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. **(C)** Incl. def'd chgs. In '17: $8.27/sh. **(D)** In mill., adj. for stock split. **(E)** Rate allowed on com. eq. in '17: 9.6%-11.6%; earned on avg. com. eq., '17: 11.7%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	65

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NORTHWESTERN NYSE-NWE

RECENT PRICE **54.59** | P/E RATIO **16.2** (Trailing: 16.3 Median: 16.0) | RELATIVE P/E RATIO **0.86** | DIV'D YLD **4.1%** | **VALUE LINE**

TIMELINESS **3** Lowered 2/23/18
SAFETY **3** New 5/4/12
TECHNICAL **5** Lowered 4/6/18
BETA .65 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+35%)	*11%*
Low	50	(-10%)	*2%*

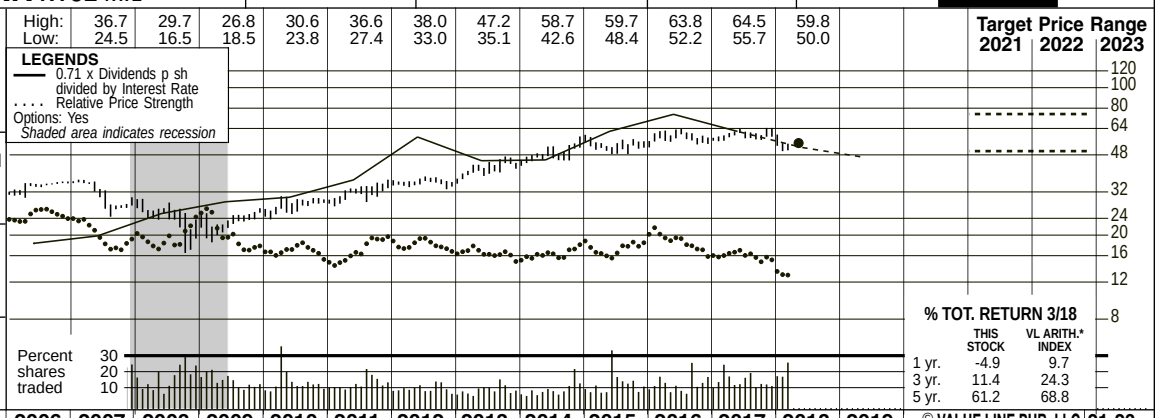
Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	1	0	0	1	0	2	15
to Sell	0	0	1	1	0	0	1	0	1

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	124	118	96
to Sell	101	100	97
Hld's(000)	56186	53930	45947

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	36.7	29.7	26.8	30.6	36.6	38.0	47.2	58.7	59.7	63.8	64.5	59.8						
Low:	24.5	16.5	18.5	23.8	27.4	33.0	35.1	42.6	48.4	52.2	55.7	50.0						



Target Price Range 2021 | 2022 | 2023
120 100 80 64 48 32 24 20 16 12 8

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.9	9.7
3 yr.	11.4	24.3
5 yr.	61.2	68.8

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	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	
	- -	- -	29.18	32.57	31.49	30.79	35.09	31.72	30.66	30.80	28.76	29.80	25.68	25.21	26.01	26.45	***26.25***	***27.00***	Revenues per sh	***29.50***
	- -	- -	3.20	4.00	3.62	3.70	4.40	4.62	4.76	5.42	5.18	5.45	5.39	5.92	6.74	6.76	***6.95***	***7.30***	"Cash Flow" per sh	***8.25***
	- -	- -	d14.32	1.71	1.31	1.44	1.77	2.02	2.14	2.53	2.26	2.46	2.99	2.90	3.39	3.34	***3.45***	***3.55***	Earnings per sh [A]	***4.00***
	- -	- -	- -	1.00	1.24	1.28	1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	2.00	2.10	***2.20***	***2.30***	Div'd Decl'd per sh [B] ■ †	***2.60***
	- -	- -	2.25	2.26	2.81	3.00	3.47	5.26	6.30	5.20	5.89	5.95	5.76	5.89	5.96	5.60	***5.70***	***6.70***	Cap'l Spending per sh	***6.25***
	- -	- -	19.92	20.60	20.65	21.12	21.25	21.86	22.64	23.68	25.09	26.60	31.50	33.22	34.68	36.44	***37.95***	***39.10***	Book Value per sh [C]	***42.75***
	- -	- -	35.60	35.79	35.97	38.97	35.93	36.00	36.23	36.28	37.22	38.75	46.91	48.17	48.33	49.37	***50.25***	***50.40***	Common Shs Outst'g [D]	***51.00***
	- -	- -	- -	17.1	26.0	21.7	13.9	11.5	12.9	12.6	15.7	16.9	16.2	18.4	17.2	17.8	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	***16.0***
	- -	- -	- -	.91	1.40	1.15	.84	.77	.82	.79	1.00	.95	.85	.93	.90	.89			Relative P/E Ratio	***.90***
	- -	- -	- -	3.4%	3.6%	4.1%	5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%	3.6%	3.4%	3.5%			Avg Ann'l Div'd Yield	***4.1%***
	1260.8	1141.9	1110.7	1117.3	1070.3	1154.5	1204.9	1214.3	1257.2	1305.7	***1320***	***1360***	Revenues ($mill)	***1500***
	67.6	73.4	77.4	92.6	83.7	94.0	120.7	138.4	164.2	162.7	***170***	***180***	Net Profit ($mill)	***205***
	37.3%	17.2%	25.0%	9.8%	9.6%	13.2%	- -	13.7%	13.7%	7.6%	***2.5%***	***3.5%***	Income Tax Rate	***6.5%***
	2.3%	4.4%	14.2%	3.3%	9.4%	8.7%	8.9%	9.8%	4.3%	5.2%	***6.0%***	***6.0%***	AFUDC % to Net Profit	***5.0%***
	46.8%	56.4%	57.2%	52.2%	53.8%	53.5%	53.4%	53.1%	52.0%	50.2%	***49.5%***	***48.5%***	Long-Term Debt Ratio	***46.0%***
	53.2%	43.6%	42.8%	47.8%	46.2%	46.5%	46.6%	46.9%	48.0%	49.8%	***50.5%***	***51.5%***	Common Equity Ratio	***54.0%***
	1434.3	1803.9	1916.4	1797.1	2020.7	2215.7	3168.0	3408.6	3493.9	3614.5	***3775***	***3840***	Total Capital ($mill)	***4050***
	1839.7	1964.1	2118.0	2213.3	2435.6	2690.1	3758.0	4059.5	4214.9	4358.3	***4465***	***4620***	Net Plant ($mill)	***4975***
	7.0%	6.0%	5.9%	7.0%	5.5%	5.5%	4.8%	5.2%	5.9%	5.6%	***5.5%***	***5.5%***	Return on Total Cap'l	***6.0%***
	8.9%	9.3%	9.4%	10.8%	9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	***9.0%***	***9.0%***	Return on Shr. Equity	***9.5%***
	8.9%	9.3%	9.4%	10.8%	9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	***9.0%***	***9.0%***	Return on Com Equity [E]	***9.5%***
	2.3%	3.2%	3.5%	4.7%	3.2%	3.5%	3.8%	3.0%	4.1%	3.4%	***3.5%***	***3.5%***	Retained to Com Eq	***3.5%***
	74%	66%	63%	56%	65%	61%	54%	65%	58%	62%	***64%***	***64%***	All Div'ds to Net Prof	***64%***

CAPITAL STRUCTURE as of 12/31/17
Total Debt $2137.3 mill. **Due in 5 Yrs** $332.0 mill.
LT Debt $1815.6 mill. **LT Interest** $83.5 mill.
Incl. $22.2 mill. capitalized leases.
(LT interest earned: 3.1x)

Pension Assets-12/17 $586.5 mill.
Oblig $696.8 mill.

Pfd Stock None

Common Stock 49,397,196 shs.
as of 2/9/18
MARKET CAP: $2.7 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.1	-.7	+3.8
Avg. Indust. Use (MWH)	30133	29784	30987
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2096	2138	2133
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.3	+1.2	+1.3
Fixed Charge Cov. (%)	252	253	275

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-2.0%	-3.0%	*2.0%*
"Cash Flow"	5.5%	5.0%	*4.0%*
Earnings	8.0%	7.0%	*3.5%*
Dividends	5.5%	7.0%	*4.5%*
Book Value	5.5%	8.0%	*3.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	346.0	270.6	272.7	325.0	1214.3
2016	332.5	293.1	301.0	330.6	1257.2
2017	367.3	283.9	309.9	344.6	1305.7
2018	***365***	***300***	***315***	***340***	***1320***
2019	***375***	***310***	***325***	***350***	***1360***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.09	.38	.51	.93	2.90
2016	.82	.73	.92	.92	3.39
2017	1.17	.44	.75	.98	3.34
2018	***1.15***	***.45***	***.80***	***1.05***	***3.45***
2019	***1.20***	***.45***	***.85***	***1.05***	***3.55***

QUARTERLY DIVIDENDS PAID [B] ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.40	.40	.40	.40	1.60
2015	.48	.48	.48	.48	1.92
2016	.50	.50	.50	.50	2.00
2017	.525	.525	.525	.525	2.10
2018	.55				

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 433,000 electric customers in Montana and South Dakota and 286,000 gas customers in Montana (87% of gross margin), South Dakota (12%), and Nebraska (1%). Electric revenue breakdown: residential, 40%; commercial, 51%; industrial, 5%; other, 4%. Generating sources: hydro, 36%; coal, 29%; wind, 6%; other, 4%; purchased, 25%. Fuel costs: 31% of revenues. '17 reported deprec. rate: 3.0%. Has 1,600 employees. Chairman: Stephen P. Adik. President & CEO: Robert C. Rowe. Inc.: Delaware. Address: 3010 West 69th Street, Sioux Falls, South Dakota 57108. Tel.: 605-978-2900. Internet: www.northwesternenergy.com.

We estimate that NorthWestern's earnings will advance moderately this year. In 2018, the company will benefit from a full year's effect of a $5.1 million gas rate hike that took effect in Montana last September. The refinancing of debt in the fourth quarter of 2017 is another plus. However, there will be some dilution from the equity issued in 2017 and 2018 via its at-the-market program. Our 2018 share-earnings estimate, which we trimmed by $0.05 a share, is within NorthWestern's targeted range of $3.35-$3.50.

An electric rate case is upcoming in Montana. The utility expects to file an application by September, with an order due by mid-2019. NorthWestern has some assets that are not reflected in rates. However, regulation in Montana has worsened in recent years, which is a cause for concern. Still, a partial year of rate relief would benefit earnings in 2019.

NorthWestern had a setback in the U.S. Court of Appeals. The utility appealed an unfavorable ruling from the Federal Energy Regulatory Commission, which ruled that just 4% of the cost of a gas-fired plant could be allocated to wholesale customers (versus the company's request for a 20% allocation). This forced NorthWestern to take a $0.12-a-share charge in 2012. Management is deciding whether pursuing this matter further is worthwhile.

Another legal matter is pending. The Montana commission disallowed recovery of certain costs associated with a plant outage in 2013. This forced NorthWestern to take a $0.13-a-share charge in the 2016. The utility is seeking relief in the Montana District Court. It expects a decision within the next 12 months.

The board of directors raised the dividend in the first quarter. The hike was $0.10 a share (4.8%) annually, the same as a year earlier. NorthWestern is targeting a payout ratio in a range of 60%-70%.

This stock has a dividend yield and 3- to 5-year total return potential that are above the utility average. This follows a price decline of more than 10% since the start of 2018. This has been a bad year for utility equities, but the falloff has been greater than most in this industry. There isn't a clear reason why.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. gain (loss) on discont. ops.: '05, (6¢); '06, 1¢; nonrec. gains: '12, 39¢ net; '15, 27¢. '15 EPS don't add due to rounding. Next earnings report due late July. **(B)** Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. **(C)** Incl. def'd charges. In '17: $14.42/sh. **(D)** In mill. **(E)** Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '14 (elec.): 9.8%; in '17 (gas): 9.55%; in SD in '15: none specified; in NE in '07: 10.4%; earned on avg. com. eq., '17: 9.5%. Regulatory Climate: Below Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	85

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OGE ENERGY CORP. NYSE-OGE

RECENT PRICE **31.20** | P/E RATIO **15.2** (Trailing: 16.3 / Median: 15.0) | RELATIVE P/E RATIO **0.80** | DIV'D YLD **4.6%** | **VALUE LINE**

TIMELINESS **3** Lowered 1/12/18
SAFETY **2** Lowered 12/18/15
TECHNICAL **4** Raised 3/16/18
BETA .95 (1.00 = Market)

2021-23 PROJECTIONS

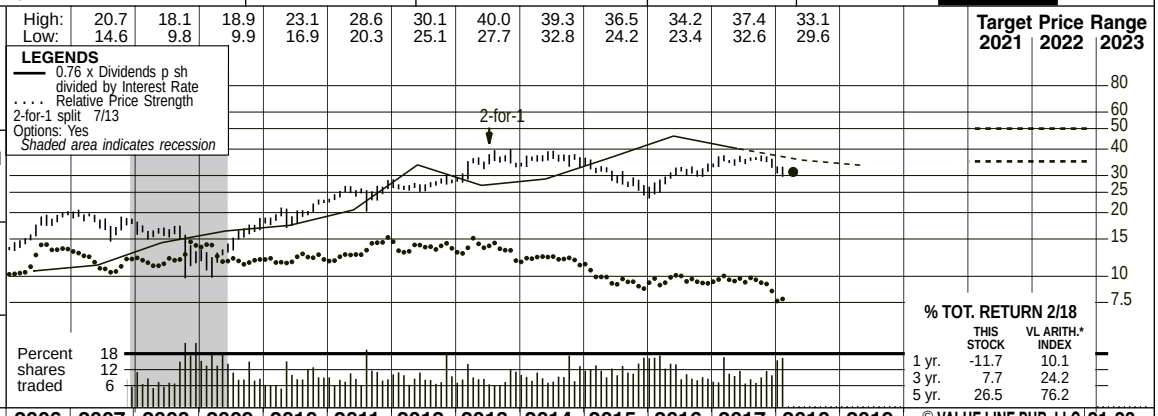
	Price	Gain	Ann'l Total Return
High	50	(+60%)	*16%*
Low	35	(+10%)	*8%*

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	1	0	0	2	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	159	151	155
to Sell	202	155	138
Hld's(000)	145860	145781	124353



2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
19.26	21.62	27.37	32.83	21.96	20.68	21.77	14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	11.32	*11.75*	*12.50*	Revenues per sh	*14.75*
1.87	1.82	1.87	1.94	2.23	2.39	2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	3.34	*3.60*	*4.00*	"Cash Flow" per sh	*4.75*
.72	.87	.89	.92	1.23	1.32	1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	1.92	*2.05*	*2.15*	Earnings per sh [A]	*2.50*
.67	.67	.67	.67	.67	.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	*1.40*	*1.54*	Div'd Decl'd per sh [B] ■	*1.85*
1.49	1.04	1.51	1.65	2.67	3.04	4.01	4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	4.13	*3.15*	*3.15*	Cap'l Spending per sh	*2.75*
6.27	6.87	7.14	7.59	8.79	9.16	10.14	10.52	11.73	13.06	14.00	15.30	16.27	16.66	17.24	19.28	*19.95*	*20.55*	Book Value per sh [C]	*22.50*
157.00	174.80	180.00	181.20	182.40	183.60	187.00	194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	199.70	*199.70*	*199.70*	Common Shs Outst'g [D]	*199.70*
14.1	11.8	14.1	14.9	13.7	13.8	12.4	10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7	18.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.0*
.77	.67	.74	.79	.74	.73	.75	.72	.85	.90	.97	.99	.96	.89	.93	.91			Relative P/E Ratio	*.95*
6.6%	6.5%	5.3%	4.9%	4.0%	3.8%	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	3.5%	3.9%	3.6%			Avg Ann'l Div'd Yield	*4.3%*
4070.7	2869.7	3716.9	3915.9	3671.2	2867.7	2453.1	2196.9	2259.2	2261.1	*2350*	*2500*	Revenues ($mill)	*2950*
231.4	258.3	295.3	342.9	355.0	387.6	395.8	337.6	338.2	384.3	*410*	*430*	Net Profit ($mill)	*500*
30.4%	31.7%	34.9%	30.7%	26.0%	24.9%	30.4%	29.2%	30.5%	32.5%	*14.0%*	*14.0%*	Income Tax Rate	*14.0%*
1.7%	9.1%	5.7%	9.0%	2.7%	2.6%	1.7%	3.7%	6.4%	15.0%	*8.0%*	*7.0%*	AFUDC % to Net Profit	*3.0%*
53.3%	50.6%	50.8%	51.6%	50.7%	43.1%	45.9%	44.3%	41.1%	41.7%	*43.0%*	*44.0%*	Long-Term Debt Ratio	*45.5%*
46.7%	49.4%	49.2%	48.4%	49.3%	56.9%	54.1%	55.7%	58.9%	58.3%	*57.0%*	*56.0%*	Common Equity Ratio	*54.5%*
4058.6	4129.7	4652.5	5300.4	5615.8	5337.2	5999.7	5971.6	5849.6	6600.7	*6980*	*7350*	Total Capital ($mill)	*8225*
5249.8	5911.6	6464.4	7474.0	8344.8	6672.8	6979.9	7322.4	7696.2	8339.9	*8660*	*8910*	Net Plant ($mill)	*9450*
7.0%	7.9%	7.8%	7.8%	7.7%	8.6%	7.8%	6.9%	7.0%	7.0%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.5%*
12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	*10.0%*	*10.5%*	Return on Shr. Equity	*11.0%*
12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	*10.0%*	*10.5%*	Return on Com Equity [E]	*11.0%*
5.4%	6.0%	6.7%	7.7%	7.2%	7.3%	6.5%	4.0%	3.3%	3.5%	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
55%	53%	48%	43%	44%	43%	47%	61%	67%	64%	*68%*	*72%*	All Div'ds to Net Prof	*74%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $3168.1 mill. **Due in 5 Yrs** $668.9 mill.
LT Debt $2749.6 mill. **LT Interest** $140.4 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $4.8 mill.

Pension Assets-12/17 $635.3 mill.
Oblig $687.5 mill.

Pfd Stock None

Common Stock 199,706,104 shs.
as of 1/31/18
MARKET CAP: $6.2 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-2.9	-1.1	-2.2
Avg. Indust. Use (MWH)	754	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.05	5.17	5.30
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6537	6538	6456
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.1	+1.0
Fixed Charge Cov. (%)	314	336	315

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-8.0%	-10.0%	*4.5%*
"Cash Flow"	4.0%	-.5%	*4.5%*
Earnings	4.5%	1.0%	*2.5%*
Dividends	5.5%	8.5%	*8.0%*
Book Value	7.5%	6.5%	*4.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	480.1	549.9	719.8	447.1	2196.9
2016	433.1	551.4	743.9	530.8	2259.2
2017	456.0	586.4	716.8	501.9	2261.1
2018	*475*	*600*	*750*	*525*	*2350*
2019	*500*	*650*	*800*	*550*	*2500*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.22	.44	.88	.15	1.69
2016	.13	.35	.92	.29	1.69
2017	.18	.52	.92	.30	1.92
2018	*.20*	*.50*	*1.05*	*.30*	*2.05*
2019	*.20*	*.55*	*1.10*	*.30*	*2.15*

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.225	.225	.225	.25	.93
2015	.25	.25	.25	.275	1.03
2016	.275	.275	.275	.3025	1.13
2017	.3025	.3025	.3025	.3325	1.24
2018	.3325				

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 842,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 25.7% of Enable Midstream Partners. Electric revenue breakdown: residential, 40%; commercial, 26%; industrial, 9%; oilfield, 7%; other, 18%. Generating sources: coal, 34%; gas, 25%; wind, 4%; purchased, 37%. Fuel costs: 40% of revenues. '17 reported depreciation rate (utility): 2.5%. Has 2,400 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321. Telephone: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary has filed a general rate case in Oklahoma. Oklahoma Gas and Electric is asking the Oklahoma Corporation Commission (OCC) for an increase of $1.9 million, based on a return of 9.9% on a common-equity ratio of 53%. (The request would have been over $70 million were it not for the pass-through to customers of reduced federal taxes.) The utility is seeking to place in the rate base a $390 million project to modernize the 462-megawatt Mustang gas-fired plant; restore the depreciation rates to their level before the OCC cut these last year; and raise its allowed ROE from the current 9.5%. New tariffs are expected to take effect at the start of October. Note that in Arkansas, OG&E will recover its investment in Mustang through the state's formula rate plan.

The new federal tax law is benefiting earnings. The revaluation of deferred taxes produced a nonrecurring gain of $1.18 a share in the fourth quarter of 2017. This year, the lower tax rate applied to OGE Energy's income from its interest in Enable Midstream Partners will add $0.08 to share net.

Rate relief should benefit the company's profits this year and next. Our 2018 estimate of $2.05 a share is at the upper end of OGE Energy's targeted range of $1.90-$2.05. Also, we expect higher equity income from the stake in Enable as the master limited partnership's prospects improve.

Two environmental compliance projects are on track for completion by yearend. OG&E is adding scrubbers to two units at the Sooner coal-fired plant at a cost of $542 million. Another coal-fired unit is being converted to a gas-fired facility at cost of $76 million. The utility will file a rate application in Oklahoma in late 2018 in order to place these projects in the rate base.

The dividend yield of this stock is above the utility average. What's more, OGE Energy expects to hike the disbursement by 10% annually through next year. Even if the board doesn't maintain such a high growth rate beyond 2019, the increases we project should produce a respectable total return over the 3- to 5-year period.

Paul E. Debbas, CFA *March 16, 2018*

(A) Dil. EPS. Excl. nonrecur. gain (losses): '02, (20¢); '03, (7¢); '04, (3¢); '15, (33¢); '17, $1.18; gains on disc. ops.: '02, 6¢; '05, 25¢; '06, 20¢. Next earnings report due early May. **(B)** Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan available. **(C)** Incl. deferred charges. In '17: $1.42/sh. **(D)** In mill., adj. for split. **(E)** Rate base: Net original cost. Rate allowed on com. eq. in OK in '16: 9.5%; in AR in '11: 9.95%; earned on avg. com. eq., '17: 17.0%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	55
Earnings Predictability	80

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OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE **40.35** | P/E RATIO **20.9** (Trailing: 21.7 Median: 24.0) | RELATIVE P/E RATIO **1.09** | DIV'D YLD **3.3%** | **VALUE LINE**

TIMELINESS **2** Lowered 3/2/18
SAFETY **2** Raised 6/17/16
TECHNICAL **3** Lowered 2/23/18
BETA .85 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+25%)	9%
Low	40	(Nil)	4%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	1	0	0	2	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	78	56	67
to Sell	53	61	50
Hld's(000)	18580	18762	16678

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
High:	39.4	46.2	25.4	25.4	23.5	25.3	31.9	32.7	33.4	42.6	48.7	44.9								
Low:	29.0	15.0	15.5	18.2	17.5	20.7	25.2	26.5	24.8	25.8	35.7	39.0								
	27.75	29.28	30.45	35.59	37.43	41.50	37.06	29.03	31.08	29.86	23.76	24.63	21.48	20.60	20.42	21.47	***22.25***	***22.95***	Revenues per sh	***26.15***
	3.44	3.30	2.88	3.35	3.39	3.55	2.81	2.76	2.60	2.36	2.71	3.02	3.09	3.14	3.44	3.70	***3.90***	***4.15***	"Cash Flow" per sh	***5.00***
	1.79	1.51	1.50	1.78	1.69	1.78	1.09	.71	.38	.45	1.05	1.37	1.55	1.56	1.60	1.86	***1.90***	***2.05***	Earnings per sh [A]	***2.50***
	1.06	1.08	1.10	1.12	1.15	1.17	1.19	1.19	1.19	1.19	1.19	1.19	1.21	1.23	1.25	1.28	***1.34***	***1.38***	Div'd Decl'd per sh [B] ■	***1.55***
	2.95	1.97	1.72	2.04	2.35	5.43	7.51	4.95	2.38	2.04	3.20	4.53	4.40	4.23	4.10	3.36	***2.75***	***9.65***	Cap'l Spending per sh	***2.45***
	12.25	12.98	14.81	15.80	16.67	17.55	19.14	18.78	17.57	15.83	14.43	14.75	15.39	15.98	17.03	17.62	***18.75***	***19.75***	Book Value per sh [C]	***24.45***
	25.59	25.72	28.98	29.40	29.52	29.85	35.38	35.81	36.00	36.10	36.17	36.27	37.22	37.86	39.35	39.56	***40.00***	***41.00***	Common Shs Outst'g [D]	***44.00***
	16.0	17.8	17.3	15.4	17.3	19.0	30.1	31.2	55.1	47.5	21.7	21.1	18.8	18.2	20.2	22.1			Avg Ann'l P/E Ratio	***18.0***
	.87	1.01	.91	.82	.93	1.01	1.81	2.08	3.51	2.98	1.38	1.19	.99	.92	1.06	1.10			Relative P/E Ratio	***1.00***
	3.7%	4.0%	4.2%	4.1%	3.9%	3.5%	3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	4.1%	4.3%	3.9%	3.1%			Avg Ann'l Div'd Yield	***3.4%***
	1311.2	1039.5	1119.1	1077.9	859.2	893.3	799.3	779.8	803.5	849.4	***890***	***940***	Revenues ($mill)	***1150***
	35.1	26.0	13.6	16.4	39.0	50.2	56.9	58.6	62.0	73.9	***75.0***	***85.0***	Net Profit ($mill)	***110***
	30.0%	- -	- -	14.5%	5.2%	21.3%	22.5%	27.0%	24.5%	27.3%	***21.0%***	***21.0%***	Income Tax Rate	***21.0%***
	6.1%	4.0%	.6%	3.8%	1.7%	- -	- -	- -	1.7%	3.6%	***3.0%***	***4.0%***	AFUDC % to Net Profit	***5.0%***
	32.9%	38.8%	40.2%	44.6%	44.0%	42.1%	46.5%	42.4%	43.0%	41.3%	***42.0%***	***41.5%***	Long-Term Debt Ratio	***38.5%***
	65.6%	59.8%	58.4%	54.0%	54.4%	57.9%	53.5%	57.6%	57.0%	58.7%	***58.0%***	***58.5%***	Common Equity Ratio	***61.5%***
	1032.5	1124.4	1083.3	1058.9	959.2	924.4	1071.3	1051.0	1175.4	1187.3	***1290***	***1390***	Total Capital ($mill)	***1755***
	1037.6	1098.6	1108.7	1077.5	1049.5	1167.0	1268.5	1387.8	1477.2	1539.6	***1600***	***1750***	Net Plant ($mill)	***1950***
	4.3%	3.4%	2.7%	3.2%	5.7%	6.7%	6.7%	6.7%	6.5%	7.0%	***6.5%***	***7.0%***	Return on Total Cap'l	***7.0%***
	5.1%	3.8%	2.1%	2.8%	7.3%	9.4%	9.9%	9.7%	9.3%	10.6%	***10.0%***	***10.5%***	Return on Shr. Equity [E]	***10.0%***
	5.1%	3.8%	2.0%	2.7%	7.3%	9.3%	9.9%	9.7%	9.3%	10.6%	***10.0%***	***10.5%***	Return on Com Equity	***10.0%***
	NMF	NMF	NMF	NMF	NMF	1.2%	2.2%	2.0%	2.1%	3.2%	***3.0%***	***3.5%***	Retained to Com Eq	***4.0%***
	108%	NMF	NMF	NMF	113%	87%	78%	79%	78%	69%	***72%***	***67%***	All Div'ds to Net Prof	***63%***

Bold figures are Value Line estimates

CAPITAL STRUCTURE as of 12/31/17
Total Debt $602.9 mill. **Due in 5 Yrs** $171.0 mill.
LT Debt $490.4 mill. **LT Interest** $25.0 mill.
(LT interest earned: 4.4x)

Leases, Uncapitalized Annual rentals $6 mill.
Pension Assets-12/16 $285.3 mill. **Oblig.** $352.7 mill.
Pfd Stock None

Common Stock 39,626,594 shs.
as of 2/8/18
MARKET CAP: $1.6 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-2.2	3.4	1.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	350	348	426

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-6.0%	-6.0%	*4.0%*
"Cash Flow"	- -	6.0%	*6.5%*
Earnings	-.5%	21.5%	*7.0%*
Dividends	1.0%	1.0%	*3.5%*
Book Value	- -	1.0%	*6.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	202.8	188.2	200.0	188.8	779.8
2016	206.2	203.5	197.2	196.6	803.5
2017	214.1	212.1	216.5	206.7	849.4
2018	***225***	***225***	***225***	***215***	***890***
2019	***240***	***235***	***240***	***225***	***940***

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.37	.36	.42	.41	1.56
2016	.38	.41	.37	.44	1.60
2017	.49	.42	.45	.50	1.86
2018	***.54***	***.44***	***.45***	***.47***	***1.90***
2019	***.58***	***.47***	***.48***	***.52***	***2.05***

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.303	.303	.303	.303	1.21
2015	.308	.308	.308	.308	1.23
2016	.313	.313	.313	.313	1.25
2017	.320	.320	.320	.320	1.28
2018	.335				

LEGENDS
1.10 x Dividends p sh divided by Interest Rate
. . . . Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2021 | 2022 | 2023

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.2	10.1
3 yr.	36.3	24.2
5 yr.	67.4	76.2

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to over 130,000 customers in Minnesota (53% of retail elec. revs.), North Dakota (38%), and South Dakota (9%). Electric rev. breakdown, '17: residential, 31%; commercial & farms, 35%; industrial, 32%; other, 2%. Fuel costs: 14.7% of revenues. Also has operations in manufacturing and plastics. 2017 depr. rate: 3.1%. Has 2,097 employees. Off. and dir. own 1.7% of common stock; The Vanguard Group, 9.2%; Cascade Investment, LLC, 8.7%; BlackRock, Inc., 6.5% (3/18 Proxy). Chairman: Nathan I. Partain. CEO: Charles S. MacFarlane. Inc.: MN. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Tel.: 866-410-8780. Web: www.ottertail.com.

Shares of Otter Tail have traded lower in price since early December. The pullback followed a strong advance that began in the first quarter of 2016. We think the equity had just gotten a bit ahead of itself. The company posted moderate revenue growth for the December period. Share net increased nearly 14%, to $0.50. Our bottom-line presentation excludes a nonrecurring charge of $1.8 million ($0.05 a share) related to the U.S. Tax Cuts and Jobs Act. Including this charge, share earnings would have been $0.45.

The company is seeking higher rates in North Dakota. Last November, Otter Tail Power Company filed a rate case with the North Dakota Public Service Commission. It is seeking to increase base rates by roughly $13 million (8.7%). The commission granted an 8.6% interim rate increase (effective January 1, 2018), while it considers the overall request. A final determination is expected by the end of the current year.

We anticipate healthy performance going forward. Investment in renewable energy and natural gas generation projects ought to foster strong rate-base growth going forward. All told, Otter Tail Power Company plans to spend roughly $900 million on capital projects through 2022. The pace of capital expenditures should be fairly uneven during this time. Utility spending is expected to approximate $95 million for 2018 and over $380 million for 2019. Elsewhere, the plastics line will likely continue to perform well, and we envision further improvement at the company's manufacturing operations.

Short-term traders may want to take a closer look. This stock is ranked to outperform the broader market averages for the coming six to 12 months. Moreover, Otter Tail earns good marks for Safety, Financial Strength, and Price Stability. Volatility is subdued, as well.

But investors with a long time horizon may prefer to remain on the sidelines at this juncture. Despite the recent selloff, total return potential appears lackluster here. The shares presently trade near the low end of our Target Price Range. The dividend yield is respectable, though not especially compelling for a utility.

Michael Napoli, CFA *March 16, 2018*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from discont. operations: '04, 8¢; '05, 33¢; '06, 1¢; '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢; '15, 2¢; '16, 1¢; '17, 1¢. Next earnings report due late April/early May. **(B)** Div'ds historically paid in early March, June, Sept., and Dec. ■ Div'd reinvestment plan avail. **(C)** Incl. intangibles. In '17: $51.3 mill., $1.30/sh. **(D)** In mill. **(E)** Regulatory Climate: MN, ND, Average; SD, Above Average.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	30
Earnings Predictability	55

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PG&E CORP. NYSE-PCG

RECENT PRICE **46.80** | P/E RATIO **13.7** (Trailing: 13.4 / Median: 18.0) | RELATIVE P/E RATIO **0.73** | DIV'D YLD **Nil** | **VALUE LINE**

TIMELINESS **4** Lowered 3/30/18
SAFETY **3** Lowered 12/29/17
TECHNICAL **5** Lowered 3/16/18
BETA .65 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+40%)	*10%*
Low	45	(-5%)	*2%*

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	7	0	0	0	0	0	0	0	9
to Sell	0	0	3	0	0	1	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	297	282	283
to Sell	237	241	296
Hld's(000)	450461	447854	410680

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
High:	52.2	45.7	45.8	48.6	48.0	47.0	48.5	55.2	60.2	65.4	71.6	47.0								
Low:	42.6	26.7	34.5	34.9	36.8	39.4	39.9	39.4	47.3	50.7	41.6	37.3								
	32.74	25.05	26.47	31.78	36.02	37.42	40.51	36.15	35.02	36.28	34.92	34.16	35.91	34.21	34.85	33.29	*33.25*	*34.15*	Revenues per sh	*38.25*
	1.14	4.80	5.71	7.12	7.76	8.02	8.44	8.37	8.22	8.08	7.32	6.33	8.13	7.29	8.23	9.03	*9.25*	*9.45*	"Cash Flow" per sh	*10.75*
	d2.36	2.05	2.12	2.35	2.76	2.78	3.22	3.03	2.82	2.78	2.07	1.83	3.06	2.00	2.83	3.50	*3.50*	*3.55*	Earnings per sh [A]	*4.25*
	- -	- -	- -	1.23	1.32	1.44	1.56	1.68	1.82	1.82	1.82	1.82	1.82	1.82	1.93	1.55	*Nil*	*2.00*	Div'd Decl'd per sh [B]	*2.30*
	7.94	4.08	3.72	4.90	6.90	7.83	10.05	10.68	9.62	9.79	10.74	11.40	10.16	10.51	11.26	10.96	*12.10*	*11.40*	Cap'l Spending per sh	*11.50*
	9.47	10.12	20.62	19.60	22.44	24.18	25.97	27.88	28.55	29.35	30.35	31.41	33.09	33.69	35.39	37.34	*41.05*	*42.75*	Book Value per sh [C]	*48.50*
	381.67	416.52	418.62	368.27	348.14	353.72	361.06	370.60	395.23	412.26	430.72	456.67	475.91	492.03	506.89	514.76	*520.00*	*527.00*	Common Shs Outst'g [D]	*550.00*
	- -	9.5	13.8	15.4	14.8	16.8	12.1	13.0	15.8	15.5	20.7	23.7	15.0	26.4	21.1	18.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.0*
	- -	.54	.73	.82	.80	.89	.73	.87	1.01	.97	1.32	1.33	.79	1.33	1.11	.92			Relative P/E Ratio	*.70*
	- -	- -	- -	3.4%	3.2%	3.1%	4.0%	4.3%	4.1%	4.2%	4.2%	4.2%	4.0%	3.4%	3.2%	2.4%			Avg Ann'l Div'd Yield	*4.1%*
	14628	13399	13841	14956	15040	15598	17090	16833	17666	17135	*17300*	*18000*	Revenues ($mill)	*21000*
	1198.0	1168.0	1113.0	1132.0	893.0	828.0	1450.0	988.0	1431.0	1807.0	*1825*	*1905*	Net Profit ($mill)	*2370*
	26.2%	31.1%	33.0%	30.3%	23.9%	24.5%	19.2%	- -	3.7%	16.8%	*10.0%*	*10.0%*	Income Tax Rate	*10.0%*
	9.5%	11.9%	14.4%	11.2%	17.5%	17.9%	10.0%	15.7%	11.4%	7.0%	*8.0%*	*8.0%*	AFUDC % to Net Profit	*6.0%*
	52.2%	51.4%	49.6%	48.8%	48.7%	46.6%	48.5%	48.8%	47.1%	47.7%	*45.5%*	*45.5%*	Long-Term Debt Ratio	*48.5%*
	46.5%	47.4%	49.3%	50.2%	50.4%	52.5%	50.7%	50.4%	52.1%	51.6%	*53.5%*	*53.5%*	Common Equity Ratio	*51.0%*
	20163	21793	22863	24119	25956	27311	31050	32858	34412	37225	*39750*	*41925*	Total Capital ($mill)	*52100*
	26261	28892	31449	33655	37523	41252	43941	46723	50581	53789	*57125*	*60025*	Net Plant ($mill)	*68500*
	7.8%	6.7%	6.2%	5.9%	4.7%	4.2%	5.8%	4.1%	5.2%	5.9%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
	12.4%	11.0%	9.6%	9.2%	6.7%	5.7%	9.1%	5.9%	7.9%	9.3%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
	12.6%	11.2%	9.7%	9.2%	6.7%	5.7%	9.1%	5.9%	7.9%	9.3%	*8.5%*	*8.5%*	Return on Com Equity [E]	*9.0%*
	6.8%	5.5%	3.9%	3.4%	1.0%	.2%	3.9%	.7%	2.8%	4.0%	*8.5%*	*3.5%*	Retained to Com Eq	*4.0%*
	47%	52%	61%	63%	85%	96%	58%	88%	65%	57%	*Nil*	*56%*	All Div'ds to Net Prof	*54%*

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-32.8	9.7
3 yr.	-10.3	24.3
5 yr.	14.7	68.8

CAPITAL STRUCTURE as of 12/31/17
Total Debt $19129 mill. **Due in 5 Yrs** $4339 mill.
LT Debt $17753 mill. **LT Interest** $817 mill.
(LT interest earned: 3.6x)
Leases, Uncapitalized Annual rentals $44 mill.
Pension Assets-12/17 $16652 mill.
Oblig $18757 mill.
Pfd Stock $252 mill. **Pfd Div'd** $14 mill.
4,534,958 shs. 4.36% to 5%, cumulative and $25 par, redeemable from $25.75 to $27.25; 5,784,825 shs. 5.00% to 6.00%, cumulative nonredeemable and $25 par. Div'ds suspended as of 12/17.
Common Stock 514,969,045 shs. **as of 2/1/18**
MARKET CAP: $24 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.5	-3.3	-1.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	9.73	9.90	10.55
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.7	+.7	+.7
Fixed Charge Cov. (%)	189	242	310

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-.5%	-.5%	*2.0%*
"Cash Flow"	.5%	1.0%	*4.5%*
Earnings	.5%	1.5%	*7.5%*
Dividends	3.0%	-.5%	*4.5%*
Book Value	5.0%	4.0%	*5.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	3899	4217	4550	4167	16833
2016	3974	4169	4810	4713	17666
2017	4268	4250	4517	4100	17135
2018	*4200*	*4200*	*4500*	*4400*	*17300*
2019	*4350*	*4350*	*4700*	*4600*	*18000*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.27	.83	.63	.27	2.00
2016	.22	.46	.77	1.36	2.83
2017	1.13	.79	1.07	.51	3.50
2018	*1.05*	*.80*	*1.05*	*.60*	*3.50*
2019	*1.05*	*.80*	*1.05*	*.65*	*3.55*

QUARTERLY DIVIDENDS PAID [B]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.455	.455	.455	.455	1.82
2015	.455	.455	.455	.455	1.82
2016	.455	.455	.49	.49	1.89
2017	.49	.49	.53	.53	2.04
2018	- -				

BUSINESS: PG&E Corporation is a holding company for Pacific Gas and Electric Company and nonutility subsidiaries. Supplies electricity and gas to most of northern and central California (population 16 million). Has 5.4 million electric and 4.5 million gas customers. Electric revenue breakdown: residential, 41%; commercial, 39%; industrial, 12%; agricultural, 8%; other, less than 1%. Generating sources: nuclear, 27%; hydro, 17%; gas, 9%; purchased, 47%. Fuel costs: 30% of revenues. '17 reported depreciation rate (utility): 3.8%. Has 23,000 employees. Chairman: Richard C. Kelly. President & CEO: Geisha J. Williams. Incorporated: California. Address: 77 Beale Street, P.O. Box 770000, San Francisco, California 94177. Telephone: 415-973-1000. Internet: www.pgecorp.com.

Uncertainty about matters stemming from wildfires in northern California is weighing on the stock price of PG&E. Pacific Gas and Electric is facing the possibility of huge liabilities for damages from the wildfires in its service area last year. The cause of the fires has not yet been determined, but under California's inverse condemnation law, a utility may be liable for damages (and attorneys' fees) caused by its power lines, even if it followed accepted inspection and safety rules. What's more, there is no guarantee that the California Public Utilities Commission will grant permission for PG&E to pass these expenses through to its customers. Measures are being considered in California to address the inverse condemnation problem, but even if this happens, this might come too late to alleviate the risks from last year's fires. The price chart above shows that the quotation is sharply below its 2017 high.

The common and preferred dividends remain suspended. The move conserves cash and will reduce PG&E's equity needs. Management has said the board of directors will "revisit the issue as we get more clarity," and that a dividend reinstatement is possible if the company is "able to narrow the current broad range of potential exposure and uncertainty." It is hard to predict when (and at what level) this will happen. Although we are estimating restoration of a payout in 2019, we think this is the best-case scenario.

Our earnings presentation will *include* any expenses stemming from the wildfires. This is how we have been treating costs associated with a smaller wildfire from 2015, as well as those incurred for several years following a gas pipeline explosion in 2010. Wildfire-related expenses reduced earnings by $0.11 a share in the fourth quarter of 2017 and $0.16 for the full year. Thus, profits are more unpredictable than our Earnings Predictability index suggests.

We think the potential rewards aren't worth the risks. True, the stock price plummeted in response to the wildfire-related uncertainties, but any recovery might well be slow. Meanwhile, shareholders won't reap any dividend income while waiting for PG&E's prospects to improve.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '04, $6.95; '09, 18¢; '11, (68¢); '12, (15¢); '15, (21¢); '16, (5¢); '17, (29¢); gain from discontinued operations: '08, 41¢. '16 EPS don't sum due to change in shares outstanding. Next earnings report due early May. **(B)** Dividends suspended 12/17. **(C)** Incl. intangibles. In '17: $7.37/sh. **(D)** In mill. **(E)** Rate base: net original cost. Rate allowed on com. eq. in '15: 10.4%; earned on avg. com. eq., '17: 9.6%. Regulatory Climate: Average.

Company's Financial Strength	B
Stock's Price Stability	80
Price Growth Persistence	30
Earnings Predictability	40

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PNM RESOURCES NYSE-PNM

RECENT PRICE **39.10** | P/E RATIO **22.3** (Trailing: 20.3 Median: 18.0) | RELATIVE P/E RATIO **1.19** | DIV'D YLD **2.8%** | **VALUE LINE**

TIMELINESS **3** Lowered 3/30/18
SAFETY **3** Lowered 5/9/08
TECHNICAL **5** Lowered 4/20/18
BETA .70 (1.00 = Market)

2021-23 PROJECTIONS

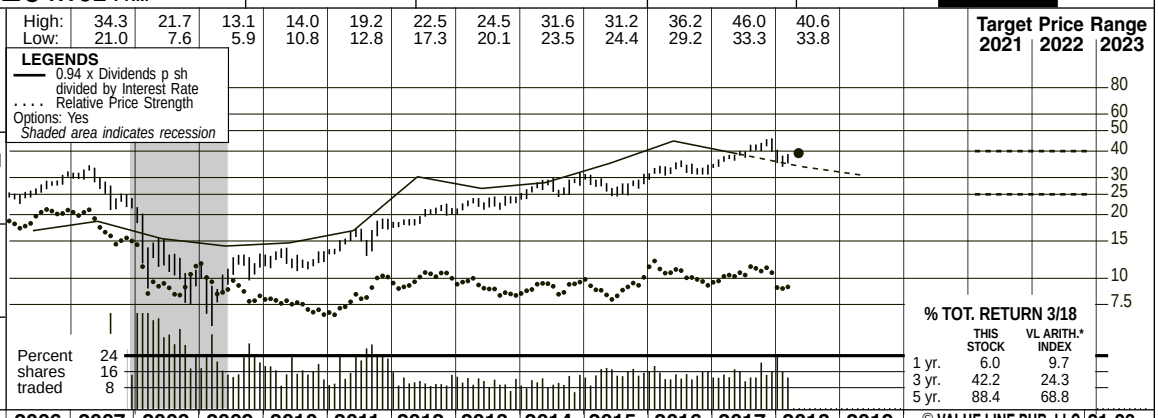
	Price	Gain	Ann'l Total Return
High	40	(Nil)	4%
Low	25	(-35%)	-6%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	1	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	0	0	2	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	124	119	133
to Sell	95	103	88
Hld's(000)	83799	82421	74432



2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
19.92	24.11	26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	18.03	18.07	17.11	18.14	*19.15*	*20.10*	Revenues per sh	*21.75*
2.83	3.05	3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.39	3.52	4.09	4.28	4.51	5.30	*5.55*	*6.15*	"Cash Flow" per sh	*7.25*
1.07	1.15	1.43	1.56	1.72	.76	.11	.58	.87	1.08	1.31	1.41	1.45	1.48	1.46	1.92	*1.85*	*2.10*	Earnings per sh A	*2.50*
.57	.61	.63	.79	.86	.91	.61	.50	.50	.50	.58	.68	.76	.82	.90	.99	*1.08*	*1.14*	Div'd Decl'd per sh B ■ †	*1.35*
4.09	2.78	2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	5.78	7.01	7.53	6.28	*6.30*	*6.60*	Cap'l Spending per sh	*8.25*
16.60	17.84	18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	22.39	20.78	21.04	21.28	*21.90*	*21.90*	Book Value per sh C	*27.00*
58.68	60.39	60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	79.65	79.65	79.65	79.65	*79.65*	*79.65*	Common Shs Outst'g D	*79.65*
15.1	14.7	15.0	17.4	15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	18.7	18.7	22.4	20.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.5*
.82	.84	.79	.93	.84	1.89	NMF	1.21	.89	.91	.95	.90	.98	.94	1.18	1.03			Relative P/E Ratio	*.75*
3.5%	3.6%	2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.8%	3.0%	2.8%	2.5%			Avg Ann'l Div'd Yield	*4.0%*
1959.5	1647.7	1673.5	1700.6	1342.4	1387.9	1435.9	1439.1	1363.0	1445.0	*1525*	*1600*	Revenues ($mill)	*1800*
8.1	54.0	80.5	97.1	106.1	114.0	116.8	118.8	117.4	154.4	*160*	*185*	Net Profit ($mill)	*225*
40.4%	30.4%	32.6%	38.8%	31.4%	31.6%	34.8%	36.9%	32.4%	33.0%	*23.5%*	*28.0%*	Income Tax Rate	*28.0%*
- -	6.3%	7.1%	8.7%	7.1%	1.3%	10.7%	17.0%	11.0%	11.9%	*11.0%*	*11.0%*	AFUDC % to Net Profit	*11.0%*
45.6%	48.7%	50.4%	51.5%	50.9%	50.0%	47.8%	54.1%	55.7%	56.1%	*54.5%*	*56.0%*	Long-Term Debt Ratio	*54.0%*
54.0%	51.0%	49.2%	48.1%	48.7%	49.7%	51.9%	45.5%	44.0%	43.6%	*45.0%*	*44.0%*	Common Equity Ratio	*45.5%*
3025.4	3214.9	3100.3	3245.6	3277.9	3344.0	3437.1	3633.3	3806.8	3887.5	*3865*	*4135*	Total Capital ($mill)	*4900*
3192.0	3332.4	3444.4	3627.1	3746.5	3933.9	4270.0	4535.4	4904.7	4980.2	*5185*	*5390*	Net Plant ($mill)	*5975*
1.9%	3.2%	4.2%	4.5%	5.1%	5.2%	5.1%	4.8%	4.7%	5.3%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
.5%	3.3%	5.2%	6.2%	6.6%	6.8%	6.5%	7.1%	7.0%	9.0%	*8.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
.5%	3.3%	5.2%	6.2%	6.6%	6.8%	6.5%	7.1%	7.0%	9.1%	*8.5%*	*9.5%*	Return on Com Equity E	*9.5%*
NMF	.5%	2.2%	3.3%	3.8%	3.8%	3.2%	3.3%	2.8%	4.5%	*3.5%*	*4.5%*	Retained to Com Eq	*4.5%*
NMF	86%	57%	47%	43%	45%	51%	54%	61%	51%	*53%*	*49%*	All Div'ds to Net Prof	*50%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $2743.0 mill. **Due in 5 Yrs** $1440.8 mill.
LT Debt $2180.8 mill. **LT Interest** $113.0 mill.
(LT interest earned: 3.2x)
Leases, Uncapitalized Annual rentals $26.8 mill.
Pension Assets-12/17 $625.5 mill.
Oblig $692.4 mill.
Pfd Stock $11.5 mill. **Pfd Div'd** $.5 mill.
115,293 shs. 4.58%, $100 par without mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs.
as of 2/20/18
MARKET CAP: $3.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-1.4	-.5	+.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	2787	2791	2580
Peak Load, Summer (Mw)	1889	1908	1843
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+.9	+.8
Fixed Charge Cov. (%)	231	202	243

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-5.0%	-1.5%	*3.5%*
"Cash Flow"	4.0%	9.0%	*7.5%*
Earnings	2.0%	8.5%	*7.5%*
Dividends	.5%	11.5%	*7.0%*
Book Value	- -	2.0%	*4.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	332.9	352.9	417.4	335.9	1439.1
2016	311.0	315.4	400.4	336.2	1363.0
2017	330.2	362.3	419.9	332.6	1445.0
2018	*345*	*370*	*440*	*370*	*1525*
2019	*360*	*390*	*460*	*390*	*1600*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.18	.40	.76	.14	1.48
2016	.13	.34	.68	.31	1.46
2017	.29	.47	.92	.25	1.92
2018	*.27*	*.43*	*.80*	*.35*	*1.85*
2019	*.30*	*.50*	*.90*	*.40*	*2.10*

QUARTERLY DIVIDENDS PAID B ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.185	.185	.185	.185	.74
2015	.20	.20	.20	.20	.80
2016	.22	.22	.22	.22	.88
2017	.2425	.2425	.2425	.2425	.97
2018	.265				

BUSINESS: PNM Resources, Inc. is a holding company with two regulated electric utilities. Public Service Company of New Mexico (PNM) serves 524,000 customers in north central New Mexico, incl. Albuquerque and Santa Fe. Texas-New Mexico Power Company (TNMP) transmits and distributes power to 250,000 customers in Texas. Electric rev. breakdown: residential, 39%; commercial, 37%; industrial, 5%; other, 19%. Generating sources: coal, 57%; nuclear, 30%; gas/oil, 12%; solar, 1%. Fuel costs: 28% of revenues. '17 reported deprec. rates: 2.5%-8.4%. Has 1,700 employees. Chairman, President & CEO: Patricia K. Collawn. Inc.: New Mexico. Address: 414 Silver Ave. SW, Albuquerque, NM 87102-3289. Tel.: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources' earnings will probably decline in 2018. In late 2017, Public Service Company of New Mexico received a rate increase that will be phased in over a two-year period beginning this year. Because the utility isn't getting the entire raise right away, but higher expenses are already in effect, this will hurt the bottom line this year. PNM raised its earnings guidance from $1.70-$1.80 to $1.77-$1.87 to reflect the effects of tax reform. We boosted our estimate by $0.15 a share, to $1.85. Note that a regulatory disallowance in the rate case forced the company to take a $27 million pretax charge against fourth-quarter results, which we *excluded* from our earnings presentation as a nonrecurring item. We also excluded a $57.5 million charge associated with the remeasurement of deferred taxes following the new federal tax law.

Earnings should advance strongly in 2019. P.S. of New Mexico will receive the second phase of the aforementioned tariff hike. In addition, Texas-New Mexico Power Company plans to file a rate application in Texas next month. An order is expected in December, with new rates taking effect in January. Our 2019 profit forecast is at the midpoint of the company's targeted range of $2.04-$2.16 a share.

Dividend hikes have been strong over the past several years, but the growth rate is decelerating. Since 2012, this rate has been in a low double-digit range, on average. However, the company expects future dividend increases to mirror its long-term earnings growth rate, at approximately 6%. This pace is still slightly above the mean for the electric utility industry.

We believe more-attractive selections are available elsewhere. The company is facing some challenges. P.S. of New Mexico isn't seeing any load growth (on a weather-normalized basis). The regulatory climate in the state is difficult. (In fact, the utility's appeal of the rate order it received in 2015 is still pending before the New Mexico Supreme Court.) The dividend yield is below average for a utility. Total return potential over the 3- to 5-year period is low, given that the recent quotation is near the upper end of our 2021-2023 Target Price Range.

Paul E. Debbas, CFA *April 27, 2018*

(A) Dil. EPS. Excl. nonrec. gains (losses): '03, 67¢; '05, (56¢); '08, ($3.77); '10, ($1.36); '11, 88¢; '13, (16¢); '15, ($1.28); '17, (92¢). Excl. gains from disc. ops.: '08, 42¢; '09, 78¢. '15 & '17 EPS don't sum due to rounding. Next egs. report due late July. **(B)** Div'ds paid mid-Feb., May, Aug., & Nov. ■ Div'd reinvest. plan avail. † Shrhldr. invest. plan avail. **(C)** Incl. intang. In '17: $12.19/sh. **(D)** In mill., adj. for split. **(E)** Rate base: net orig. cost. Rate all'd on com. eq. in '18: 9.575%; earn. on avg. com. eq., '17: 8.9%. Reg. Climate: NM, Below Avg.; TX, Avg.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	95
Earnings Predictability	70

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PINNACLE WEST NYSE-PNW

RECENT PRICE **80.15** | P/E RATIO **18.1** (Trailing: 18.1 Median: 15.0) | RELATIVE P/E RATIO **0.96** | DIV'D YLD **3.6%** | **VALUE LINE**

TIMELINESS **4** Lowered 3/30/18
SAFETY **1** Raised 5/3/13
TECHNICAL **5** Lowered 4/6/18
BETA .65 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+10%)	7%
Low	75	(-5%)	3%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	12	0	0	1	12
to Sell	0	0	3	0	0	2	1	1	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	194	218	182
to Sell	224	185	183
Hld's(000)	107032	104825	94333

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
High:	51.7	42.9	38.0	42.7	48.9	54.7	61.9	71.1	73.3	82.8	92.5	85.6								
Low:	36.8	26.3	22.3	32.3	37.3	45.9	51.5	51.2	56.0	62.5	75.8	73.8								
	28.90	30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.58	31.50	31.42	31.90	***32.80***	***34.30***	Revenues per sh	***39.75***
	7.01	7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.09	9.09	9.39	9.79	***10.10***	***10.65***	"Cash Flow" per sh	***12.75***
	2.53	2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.58	3.92	3.95	4.43	***4.50***	***4.70***	Earnings per sh [A]	***5.50***
	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	2.56	2.70	***2.86***	***3.02***	Div'd Decl'd per sh [B] ■	***3.50***
	9.81	7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	8.38	9.84	11.64	12.80	***11.25***	***10.80***	Cap'l Spending per sh	***11.00***
	29.44	31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.50	41.30	43.15	44.80	***46.35***	***48.00***	Book Value per sh [C]	***54.00***
	91.26	91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.57	110.98	111.34	111.75	***112.00***	***112.25***	Common Shs Outst'g [D]	***113.00***
	14.4	14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	16.0	18.7	19.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	***15.0***
	.79	.80	.83	1.02	.74	.79	.97	.91	.80	.92	.91	.86	.84	.81	.98	.97			Relative P/E Ratio	***.85***
	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%	3.9%	3.5%	3.2%			Avg Ann'l Div'd Yield	***4.2%***
	3367.1	3297.1	3263.6	3241.4	3301.8	3454.6	3491.6	3495.4	3498.7	3565.3	***3675***	***3850***	Revenues ($mill)	***4500***
	213.6	229.2	330.4	328.2	387.4	406.1	397.6	437.3	442.0	497.8	***505***	***535***	Net Profit ($mill)	***630***
	23.4%	36.9%	31.9%	34.0%	36.2%	34.4%	34.2%	34.3%	33.9%	32.5%	***18.0%***	***18.0%***	Income Tax Rate	***18.0%***
	17.5%	11.2%	11.7%	12.8%	9.7%	10.0%	11.6%	11.8%	14.1%	13.9%	***13.0%***	***10.0%***	AFUDC % to Net Profit	***8.0%***
	46.8%	50.4%	45.3%	44.1%	44.6%	40.0%	41.0%	43.0%	45.6%	48.9%	***48.0%***	***48.5%***	Long-Term Debt Ratio	***45.5%***
	53.2%	49.6%	54.7%	55.9%	55.4%	60.0%	59.0%	57.0%	54.4%	51.1%	***52.0%***	***51.5%***	Common Equity Ratio	***54.5%***
	6477.6	6686.6	6729.1	6840.9	7171.9	6990.9	7398.7	8046.3	8825.4	9796.4	***9985***	***10480***	Total Capital ($mill)	***11175***
	8916.7	9257.8	9578.8	9962.3	10396	10889	11194	11809	12714	13445	***14075***	***14625***	Net Plant ($mill)	***16125***
	4.7%	4.8%	6.5%	6.4%	6.8%	7.1%	6.4%	6.4%	6.0%	6.1%	***6.0%***	***6.0%***	Return on Total Cap'l	***6.5%***
	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	9.2%	9.9%	***10.0%***	***10.0%***	Return on Shr. Equity	***10.5%***
	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.1%	9.5%	9.2%	9.9%	***10.0%***	***10.0%***	Return on Com Equity [E]	***10.5%***
	.3%	.7%	3.1%	2.8%	4.1%	4.1%	3.5%	3.9%	3.5%	4.2%	***3.5%***	***3.5%***	Retained to Com Eq	***4.0%***
	96%	89%	66%	68%	58%	58%	62%	59%	62%	58%	***63%***	***63%***	All Div'ds to Net Prof	***63%***

CAPITAL STRUCTURE as of 12/31/17
Total Debt $4829.4 mill. **Due in 5 Yrs** $1188.4 mill.
LT Debt $4789.7 mill. **LT Interest** $213.6 mill.
Incl. $13.4 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 4.4x)
Leases, Uncapitalized Annual rentals $13.4 mill.
Pension Assets-12/17 $3057.0 mill.
Oblig $3394.2 mill.
Pfd Stock None

Common Stock 111,799,789 shs.
as of 2/16/18
MARKET CAP: $9.0 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+1.3	+.3	- -
Avg. Indust. Use (MWH)	658	640	620
Avg. Indust. Revs. per KWH (¢)	8.17	8.37	8.34
Capacity at Peak (Mw)	9250	9192	8438
Peak Load, Summer (Mw)	7031	7051	7363
Annual Load Factor (%)	48.3	48.0	46.3
% Change Customers (yr-end)	+1.3	+1.3	+1.8
Fixed Charge Cov. (%)	438	416	425

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-.5%	1.0%	*4.0%*
"Cash Flow"	1.5%	5.0%	*5.0%*
Earnings	4.0%	5.0%	*5.0%*
Dividends	2.5%	2.5%	*5.5%*
Book Value	2.0%	4.0%	*4.0%*

QUARTERLY REVENUES ($ mill.)

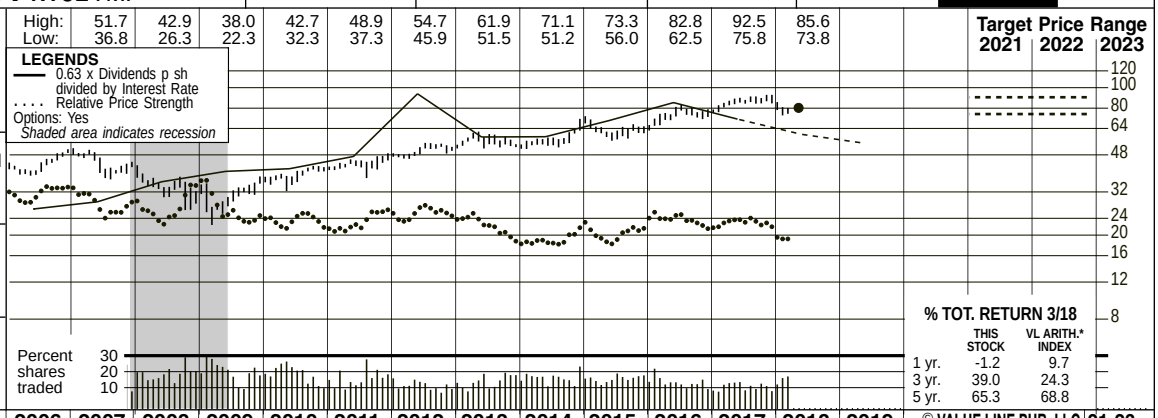
Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	671.2	890.7	1199.1	734.4	3495.4
2016	677.2	915.4	1166.9	739.2	3498.7
2017	677.7	944.6	1183.3	759.7	3565.3
2018	***700***	***975***	***1225***	***775***	***3675***
2019	***725***	***1025***	***1300***	***800***	***3850***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.14	1.10	2.30	.37	3.92
2016	.04	1.08	2.35	.47	3.95
2017	.21	1.49	2.46	.27	4.43
2018	***.25***	***1.30***	***2.60***	***.35***	***4.50***
2019	***.25***	***1.35***	***2.70***	***.40***	***4.70***

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.568	.568	.568	.595	2.30
2015	.595	.595	.595	.625	2.41
2016	.625	.625	.625	.655	2.53
2017	.655	.655	.655	.695	2.66
2018	.695				



% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.2	9.7
3 yr.	39.0	24.3
5 yr.	65.3	68.8

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.2 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 50%; commercial, 40%; industrial, 5%; other, 5%. Generating sources: nuclear, 29%; gas & other, 26%; coal, 22%; purchased, 23%. Fuel costs: 28% of revenues. '17 reported deprec. rate: 2.8%. Has 6,300 employees. Chairman, President & CEO: Donald E. Brandt. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary has asked the Arizona Corporation Commission for a rate increase. Although the rate order last year for Arizona Public Service froze base tariffs mid-2020, the ruling also allowed APS to file for recovery of an environmental project at the Four Corners coal-fired station through a rider (surcharge) on customers' bills. The utility is seeking an increase of $65 million (about 2%), and no change in the allowed return on equity of 10%. A decision is expected in time for the rider to take effect at the start of 2019. The project should be completed soon at a cost of $390 million. The costs that the company will incur this year will be deferred for recovery beginning next year under the rider.

Another large capital project is under construction. APS is building five gas-fired units and retiring two at an estimated cost of $500 million. This will increase the utility's generating capacity by 290 megawatts. Costs associated with this project will be deferred until APS recovers these in its next base rate increase, presumably in mid-2020.

We estimate a modest earnings increase this year. Pinnacle West raised its 2018 earnings guidance by a dime a share, to $4.35-$4.55, due largely because the company raised its expectation for the Allowance for Funds Used During Construction, a noncash credit to income. Additional expense-management initiatives are another factor. We raised our estimate by $0.10 a share, to $4.50.

We forecast higher profit growth in 2019. The aforementioned rate rider should help. In addition, the utility's strong (and rising) customer growth rate is stimulating modest kilowatt-hour sales growth, despite the effects of energy efficiency. Our $4.70-a-share earnings estimate would produce an increase of 4%.

This untimely stock has a dividend yield and 3- to 5-year total return potential that are about average, by utility standards. Perhaps conservative investors will find this acceptable, given the equity's top-notch Safety rank and the company's high rating for Financial Strength. However, like most utility issues, the recent price is within our 2021-2023 Target Price Range.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. nonrec. gain (losses): '02, (77¢); '09, ($1.45); '17, 8¢; gains (losses) from disc. ops.: '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). '15 & '16 EPS don't sum due to rounding. Next earnings report due early May. **(B)** Div'ds historically pd. in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinv. plan avail. **(C)** Incl. def'd chgs. In '17: $14.34/sh. **(D)** In mill. **(E)** Rate base: Fair value. Rate allowed on com. eq. in '17: 10.0%; earned on avg. com. eq., '17: 10.0%. Regul. Climate: Avg.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	95

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PORTLAND GENERAL NYSE-POR

RECENT PRICE **40.92** | P/E RATIO **18.4** (Trailing: 17.9 Median: 16.0) | RELATIVE P/E RATIO **0.98** | DIV'D YLD **3.5%** | **VALUE LINE**

TIMELINESS 4 Lowered 3/23/18
SAFETY 2 Raised 5/4/12
TECHNICAL 5 Lowered 4/20/18
BETA .65 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+20%)	*9%*
Low	35	(-15%)	*1%*

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	10	0	0	10	0	0	0	0	5
to Sell	0	0	0	0	0	0	0	0	1

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	147	122	136
to Sell	112	118	91
Hld's(000)	88988	88359	81125

	2002	2003	2004	2005[F]	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
High:	31.3	27.7	21.4	22.7	26.0	28.1	33.3	40.3	41.0	45.2	50.1	45.6								
Low:	25.5	15.4	13.5	17.5	21.3	24.3	27.4	29.0	33.0	35.3	42.4	39.0								
	--	--	--	23.14	24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	21.38	21.62	22.54	*22.70*	*23.50*	Revenues per sh	*25.75*
	--	--	--	4.75	4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	5.37	5.78	6.16	*6.40*	*6.85*	"Cash Flow" per sh	*8.00*
	--	--	--	1.02	1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	2.04	2.16	2.29	*2.20*	*2.35*	Earnings per sh [A]	*2.75*
	--	--	--	--	.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	1.26	1.34	*1.42*	*1.50*	Div'd Decl'd per sh [B] ■ †	*1.80*
	--	--	--	4.08	5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	6.73	6.57	5.77	*6.35*	*5.10*	Cap'l Spending per sh	*5.00*
	--	--	--	19.15	19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	25.43	26.35	27.11	*27.85*	*28.70*	Book Value per sh [C]	*31.50*
	--	--	--	62.50	62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	88.79	88.95	89.11	*89.25*	*89.40*	Common Shs Outst'g [D]	*90.00*
	--	--	--	--	23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	17.7	19.1	20.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.5*
	--	--	--	--	1.26	.63	.98	.96	.76	.78	.89	.95	.81	.89	1.00	1.01			Relative P/E Ratio	*.85*
	--	--	--	--	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%	3.1%	2.9%			Avg Ann'l Div'd Yield	*4.2%*
							1745.0	1804.0	1783.0	1813.0	1805.0	1810.0	1900.0	1898.0	1923.0	2009.0	*2025*	*2100*	Revenues ($mill)	*2325*
							87.0	95.0	125.0	147.0	141.0	137.0	175.0	172.0	193.0	204.0	*195*	*210*	Net Profit ($mill)	*255*
							28.7%	28.8%	30.5%	28.3%	31.4%	23.2%	26.0%	20.7%	20.6%	25.3%	*12.5%*	*12.5%*	Income Tax Rate	*12.5%*
							17.2%	31.6%	17.6%	5.4%	7.1%	14.6%	33.7%	19.8%	16.6%	8.8%	*7.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
							46.2%	50.3%	53.0%	49.6%	47.1%	51.3%	52.7%	47.8%	48.4%	50.1%	*47.0%*	*50.5%*	Long-Term Debt Ratio	*48.5%*
							53.8%	49.7%	47.0%	50.4%	52.9%	48.7%	47.3%	52.2%	51.6%	49.9%	*53.0%*	*49.5%*	Common Equity Ratio	*51.5%*
							2518.0	3100.0	3390.0	3298.0	3264.0	3735.0	4037.0	4329.0	4544.0	4842.0	*4710*	*5190*	Total Capital ($mill)	*5500*
							3301.0	3858.0	4133.0	4285.0	4392.0	4880.0	5679.0	6012.0	6434.0	6741.0	*6930*	*6985*	Net Plant ($mill)	*7000*
							5.0%	4.5%	5.4%	6.2%	5.9%	5.1%	5.8%	5.4%	5.6%	5.5%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
							6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	*8.0%*	*8.5%*	Return on Shr. Equity	*9.0%*
							6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	*8.0%*	*8.5%*	Return on Com Equity [E]	*9.0%*
							2.0%	1.5%	3.0%	4.1%	3.5%	2.9%	4.6%	3.3%	3.5%	3.6%	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
							69%	76%	62%	54%	57%	61%	50%	56%	57%	58%	*64%*	*63%*	All Div'ds to Net Prof	*63%*

% TOT. RETURN 3/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-6.0	9.7
3 yr.	19.9	24.3
5 yr.	55.5	68.8

CAPITAL STRUCTURE as of 12/31/17
Total Debt $2426 mill. **Due in 5 Yrs** $460 mill.
LT Debt $2426 mill. **LT Interest** $123 mill.
Incl. $49 mill. capitalized leases.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $9 mill.
Pension Assets-12/17 $629 mill.
Oblig $869 mill.
Pfd Stock None

Common Stock 89,114,522 shs.
as of 2/2/18

MARKET CAP: $3.6 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+.6	-2.1	+3.9
Avg. Indust. Use (MWH)	17485	16146	16041
Avg. Indust. Revs. per KWH (¢)	5.01	4.99	4.94
Capacity at Peak (Mw)	4609	4730	4743
Peak Load, Summer (Mw)	3914	3726	3976
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.2	+1.3
Fixed Charge Cov. (%)	243	271	298

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-1.5%	-2.0%	*3.0%*
"Cash Flow"	1.5%	3.0%	*5.5%*
Earnings	4.0%	3.5%	*4.0%*
Dividends	9.0%	3.5%	*6.0%*
Book Value	3.0%	3.5%	*3.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	473.0	450.0	476.0	499.0	1898.0
2016	487.0	428.0	484.0	524.0	1923.0
2017	530.0	449.0	515.0	515.0	2009.0
2018	*530*	*455*	*515*	*525*	*2025*
2019	*555*	*470*	*530*	*545*	*2100*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.62	.44	.40	.57	2.04
2016	.68	.42	.38	.68	2.16
2017	.82	.36	.44	.67	2.29
2018	*.70*	*.42*	*.43*	*.65*	*2.20*
2019	*.75*	*.45*	*.45*	*.70*	*2.35*

QUARTERLY DIVIDENDS PAID [B] ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.275	.275	.28	.28	1.11
2015	.28	.28	.30	.30	1.16
2016	.30	.30	.32	.32	1.24
2017	.32	.32	.34	.34	1.32
2018	.34	.34			

BUSINESS: Portland General Electric Company (PGE) provides electricity to 875,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 48%; commercial, 33%; industrial, 11%; other, 8%. Generating sources: gas, 28%; coal, 15%; wind, 8%; hydro, 8%; purchased, 41%. Fuel costs: 30% of revenues. '17 reported depreciation rate: 3.6%. Has 2,900 employees. Chairman: Jack E. Davis. President and Chief Executive Officer: Maria M. Pope. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric has filed a rate case. The utility requested an increase of $89 million (4.8%), based on a return of 9.5% on a common-equity ratio of 50%. An order from the Oregon Public Utility Commission (OPUC) is expected in December, with new tariffs taking effect at the start of 2019.

Earnings are likely to decline this year. Favorable weather patterns helped the bottom line in 2017, but the weather in early 2018 turned the other way. In fact, the Portland area had its second-warmest January on record. We have lowered our earnings estimate by $0.20 a share, to $2.20. Our revised estimate is within PGE's guidance of $2.10-$2.25 a share.

There is a possible risk to earnings this year. PGE is going to ask the OPUC for permission to defer (for future recovery) costs in 2018 associated with the upgraded customer information system the company expects to complete soon. If the OPUC doesn't approve this request and the utility must incur these costs, this would reduce earnings by $0.10 a share this year.

Unrecovered costs associated with the Carty gas-fired plant continue to be a drag on earnings. The facility was completed in 2016, several months after PGE declared the contractor of the project in default of the construction agreement. However, $123 million of the plant's $637 million cost are not reflected in rates. PGE filed suit against the contractor's insurer, seeking to collect a $145.6 million performance bond, plus damages. The company expects resolution of this matter to take two to four years, but was citing the same time frame two years ago. Unrecovered costs and litigation expenses reduced earnings by $0.09 a share in 2017, and the loss will widen to an estimated $0.12 a share this year due to the lower tax shield from the reduced federal tax rate.

We forecast an earnings recovery in 2019. We assume normal weather conditions and reasonable treatment in the aforementioned rate case.

This untimely stock has a dividend yield and 3- to 5-year total return potential that are about average for a utility.

Paul E. Debbas, CFA *April 27, 2018*

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	80

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(A) Diluted EPS. Excl. nonrecurring losses: '13, 42¢; '17, 19¢. '15 EPS don't sum due to rounding. Next earnings report due late July. **(B)** Div'ds paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. **(C)** Incl. deferred charges. In '17: $4.92/sh. **(D)** In mill. **(E)** Rate base: Net orig. cost. Rate allowed on com. eq. in '18: 9.5%; earned on avg. com. eq., '17: 8.5%. Regulatory Climate: Average. **(F)** '05 per-share data are pro forma, based on shs. outstanding when stock began trading in '06.

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P.S. ENTERPRISE GP. NYSE-PEG

RECENT PRICE **51.08** | P/E RATIO **16.5** (Trailing: 17.1 Median: 13.0) | RELATIVE P/E RATIO **0.93** | DIV'D YLD **3.6%** | **VALUE LINE**

TIMELINESS **3** Raised 3/9/18
SAFETY **1** Raised 11/23/12
TECHNICAL **3** Raised 5/4/18
BETA .70 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+15%)	*8%*
Low	45	(-10%)	*1%*

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	1	1	0	1	2	0	1	7	6
to Sell	1	2	0	1	2	1	1	1	1

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	338	318	276
to Sell	300	304	307
Hld's(000)	381036	384734	343240

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
High:	49.9	52.3	34.1	34.9	35.5	34.1	37.0	43.8	44.4	47.4	53.3	52.3								
Low:	32.2	22.1	23.7	29.0	28.0	28.9	29.7	31.3	36.8	37.8	41.7	46.2								
	18.62	23.54	23.09	24.74	24.07	25.28	27.94	24.57	23.31	22.42	19.33	19.71	21.52	20.61	18.22	18.14	***18.80***	***19.40***	Revenues per sh	***22.50***
	3.01	2.92	3.02	3.42	3.91	4.36	4.68	4.98	5.27	5.36	4.87	5.17	5.82	6.15	5.07	5.30	***5.80***	***6.10***	"Cash Flow" per sh	***7.50***
	1.88	1.88	1.52	1.79	1.85	2.59	2.90	3.08	3.07	3.11	2.44	2.45	2.99	3.30	2.83	2.82	***3.10***	***3.20***	Earnings per sh [A]	***3.75***
	1.08	1.08	1.10	1.12	1.14	1.17	1.29	1.33	1.37	1.37	1.42	1.44	1.48	1.56	1.64	1.72	***1.80***	***1.90***	Div'd Decl'd per sh [B] ■†	***2.20***
	4.03	2.86	2.64	2.04	2.01	2.65	3.50	3.55	4.27	4.12	5.09	5.56	5.58	7.65	8.32	8.30	***6.35***	***5.35***	Cap'l Spending per sh	***5.25***
	8.85	11.71	12.05	11.99	13.35	14.35	15.36	17.37	19.04	20.30	21.31	22.95	24.09	25.86	26.01	27.42	***28.70***	***30.05***	Book Value per sh [C]	***34.75***
	450.53	472.27	476.20	502.33	505.29	508.52	506.02	505.99	505.97	505.95	505.89	505.86	505.84	505.28	504.87	505.00	***505.00***	***505.00***	Common Shs Outst'g [D]	***505.00***
	10.0	10.6	14.3	16.5	17.8	16.5	13.6	10.0	10.4	10.4	12.8	13.5	12.6	12.4	15.3	16.3			Avg Ann'l P/E Ratio	***14.0***
	.55	.60	.76	.88	.96	.88	.82	.67	.66	.65	.81	.76	.66	.62	.80	.82			Relative P/E Ratio	***.80***
	5.7%	5.4%	5.1%	3.8%	3.5%	2.7%	3.3%	4.3%	4.3%	4.2%	4.6%	4.4%	3.9%	3.8%	3.8%	3.7%			Avg Ann'l Div'd Yield	***4.2%***
							14139	12431	11793	11343	9781.0	9968.0	10886	10415	9198.0	9161.0	***9500***	***9800***	Revenues ($mill)	***11300***
							1477.0	1567.0	1557.0	1577.0	1239.0	1243.0	1518.0	1679.0	1436.0	1431.0	***1565***	***1635***	Net Profit ($mill)	***1955***
							45.9%	42.3%	40.5%	40.4%	36.2%	39.5%	38.2%	37.4%	31.7%	37.3%	***26.5%***	***26.5%***	Income Tax Rate	***26.5%***
							3.2%	3.8%	5.5%	2.7%	4.8%	4.6%	4.5%	5.5%	8.4%	10.6%	***8.0%***	***6.0%***	AFUDC % to Net Profit	***4.0%***
							50.5%	46.3%	44.8%	42.1%	38.3%	40.4%	40.4%	40.3%	45.3%	46.6%	***47.0%***	***47.5%***	Long-Term Debt Ratio	***49.5%***
							49.0%	53.2%	55.2%	57.9%	61.7%	59.6%	59.6%	59.7%	54.7%	53.4%	***53.0%***	***52.5%***	Common Equity Ratio	***50.5%***
							15856	16513	17452	17731	17467	19470	20446	21900	24025	25915	***27375***	***28950***	Total Capital ($mill)	***34600***
							14433	15440	16390	17849	19736	21645	23589	26539	29286	31797	***33700***	***35000***	Net Plant ($mill)	***38200***
							11.2%	11.0%	10.4%	10.2%	8.1%	7.5%	8.4%	8.6%	6.8%	6.4%	***6.5%***	***6.5%***	Return on Total Cap'l	***6.5%***
							18.8%	17.7%	16.2%	15.4%	11.5%	10.7%	12.5%	12.9%	10.9%	10.3%	***11.0%***	***11.0%***	Return on Shr. Equity	***11.0%***
							19.0%	17.8%	16.2%	15.4%	11.5%	10.7%	12.5%	12.9%	10.9%	10.3%	***11.0%***	***11.0%***	Return on Com Equity [E]	***11.0%***
							10.5%	10.1%	9.0%	8.6%	4.8%	4.4%	6.3%	6.8%	4.6%	4.1%	***4.5%***	***4.5%***	Retained to Com Eq	***5.0%***
							45%	43%	45%	44%	58%	59%	49%	47%	58%	61%	***58%***	***59%***	All Div'ds to Net Prof	***57%***

Bold figures are Value Line estimates

LEGENDS
0.72 x Dividends p sh divided by Interest Rate
Relative Price Strength
2-for-1 split 2/08
Options: Yes
Shaded area indicates recession

Target Price Range 2021 | 2022 | 2023

% TOT. RETURN 4/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.8	9.5
3 yr.	40.7	25.8
5 yr.	73.3	68.8

CAPITAL STRUCTURE as of 3/31/18
Total Debt $13666 mill. **Due in 5 Yrs** $6287 mill.
LT Debt $12072 mill. **LT Interest** $465 mill.
(LT interest earned: 5.6x)

Leases, Uncapitalized Annual rentals $36 mill.

Pension Assets-12/17 $5812 mill.
Oblig $6359 mill.

Pfd Stock None

Common Stock 505,217,435 shs.
as of 4/17/18
MARKET CAP: $26 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+2.4	-.3	-2.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH(¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	9595	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	705	522	503

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-2.5%	-2.5%	*3.0%*
"Cash Flow"	3.5%	1.5%	*5.5%*
Earnings	3.5%	1.0%	*4.0%*
Dividends	3.5%	3.5%	*5.0%*
Book Value	7.0%	5.5%	*4.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	3135	2314	2688	2278	10415
2016	2616	1905	2587	2090	9198.0
2017	2647	2155	2263	2096	9161.0
2018	2818	***2150***	***2382***	***2150***	***9500***
2019	***2900***	***2200***	***2500***	***2200***	***9800***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.15	.68	.87	.60	3.30
2016	.93	.37	.94	.59	2.83
2017	.94	.69	.78	.42	2.82
2018	1.10	***.60***	***.85***	***.55***	***3.10***
2019	***1.05***	***.65***	***.90***	***.60***	***3.20***

QUARTERLY DIVIDENDS PAID [B] ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.37	.37	.37	.37	1.48
2015	.39	.39	.39	.39	1.56
2016	.41	.41	.41	.41	1.64
2017	.43	.43	.43	.43	1.72
2018	.45				

BUSINESS: Public Service Enterprise Group Incorporated is a holding company for Public Service Electric and Gas Company (PSE&G), which serves 2.2 million electric and 1.8 million gas customers in New Jersey, and PSEG Power LLC, a nonregulated power generator with nuclear, gas, and coal-fired plants in the Northeast. PSEG Energy Holdings is involved in renewable energy. The company no longer breaks out data on electric and gas operating statistics. Fuel costs: 31% of revenues. '17 reported depreciation rates (utility): 1.6%-2.5%. Has 12,900 employees. Chairman, President & Chief Executive Officer: Dr. Ralph Izzo. Inc.: New Jersey. Address: 80 Park Plaza, P.O. Box 1171, Newark, New Jersey 07101-1171. Telephone: 973-430-7000. Internet: www.pseg.com.

Public Service Enterprise Group's utility subsidiary has a general rate case pending. Public Service Electric and Gas is seeking slight (due to the effects of the new federal tax law) electric and gas tariff increases, based on a 10.3% return on a 54% common-equity ratio. The utility wants to recover costs that aren't recoverable through various regulatory mechanisms that provide for concurrent recovery; increase its depreciation rate; recoup storm-related costs that were deferred; and decouple electric revenues and volume. PSE&G is hoping for new rates and the decoupling mechanism to take effect at the start of October.

The utility has become the largest contributor to PSEG's profits. This is due to growth in PSE&G's income (helped by rising transmission investment) and a decline in margins at PSEG's primary nonutility subsidiary, PSEG Power, due to difficult conditions in the power markets. PSE&G expects its rate base to climb at an average annual rate of 7%-9% through 2022, and should reach the upper end of this range if the New Jersey Board of Public Utilities approves a settlement that would extend the utility's gas system modernization program for five years, beginning in 2019. Under this program, PSE&G would spend nearly $1.9 billion. All told, we expect a strong earnings increase in 2018 and a more modest rise next year.

PSEG Power's nuclear units in New Jersey might get some help from the state government. The company has indicated that without subsidies, market conditions might force the closing of these plants. So, the state legislature passed a law (which awaits the governor's approval) that would provide for "zero emission certificates" that recognize the benefits of nuclear energy because it has no carbon emissions and provides fuel diversity.

The board raised the dividend in February. The quarterly increase was two cents a share (4.7%). We project a similar dividend growth rate over the 3- to 5-year period.

This high-quality stock has a dividend yield that is about average for a utility. With the recent quotation well within our 2021-2023 Target Price Range, total return potential is unexciting.

Paul E. Debbas, CFA *May 18, 2018*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '02, ($1.30); '05, (3¢); '06, (35¢); '08, (96¢); '09, 6¢; '11, (34¢); '12, 7¢; '16, (30¢); '17, 28¢ (net); gains (loss) from disc. ops.: '05, (33¢); '06, 12¢; '07, 3¢; '08, 40¢; '11, 13¢. '17 EPS don't sum due to rounding. Next egs. report due late July. **(B)** Div'ds historically paid in late Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. **(C)** Incl. intang. In '17: $6.64/sh. **(D)** In mill., adj. for split. **(E)** Rate base: Net orig. cost. Rate all'd on com. eq. in '10: 10.3%; earned on avg. com. eq., '17: 10.6%. Reg. Climate: Avg.

Company's Financial Strength	A++
Stock's Price Stability	95
Price Growth Persistence	20
Earnings Predictability	65

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PPL CORPORATION NYSE-PPL

RECENT PRICE **27.45** | P/E RATIO **12.2** (Trailing: 12.6 Median: 13.0) | RELATIVE P/E RATIO **0.69** | DIV'D YLD **6.0%** | **VALUE LINE**

TIMELINESS **4** Raised 5/11/18
SAFETY **2** Raised 8/21/15
TECHNICAL **4** Raised 5/18/18
BETA .75 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+65%)	*18%*
Low	35	(+30%)	*12%*

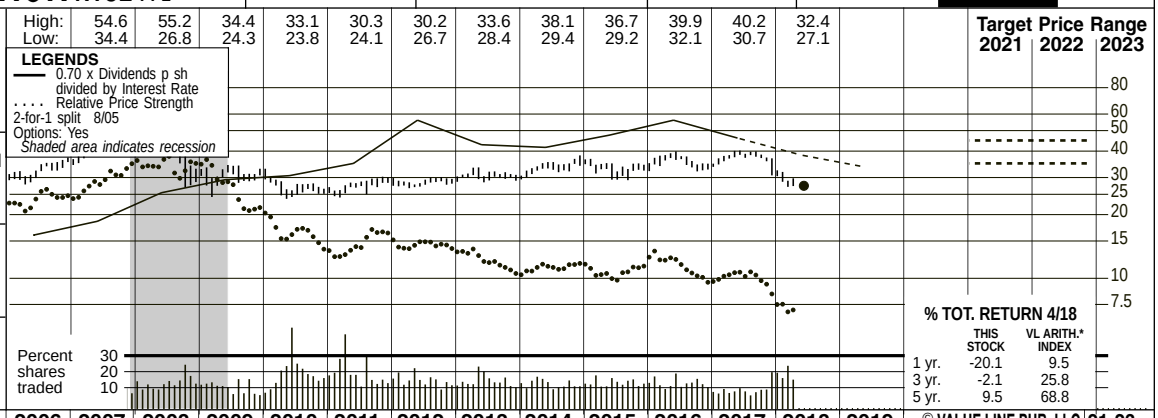
Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	0	0	0	0	8	0	1
to Sell	1	3	0	0	0	0	3	1	3

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	364	337	337
to Sell	304	329	292
Hld's(000)	537294	539614	510699

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	54.6	55.2	34.4	33.1	30.3	30.2	33.6	38.1	36.7	39.9	40.2	32.4						
Low:	34.4	26.8	24.3	23.8	24.1	26.7	28.4	29.4	29.2	32.1	30.7	27.1						



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16.38	15.75	15.37	16.36	17.92	17.41	21.47	20.03	17.63	22.02	21.11	18.82	17.27	11.38	11.06	10.74	*10.20*	*10.35*
3.20	3.60	3.59	3.84	4.26	5.10	4.71	3.47	3.66	4.59	4.84	4.64	4.58	3.78	4.28	3.68	*3.70*	*4.00*
1.54	1.84	1.87	1.92	2.29	2.63	2.45	1.19	2.29	2.61	2.61	2.38	2.38	2.37	2.79	2.11	*2.25*	*2.35*
.72	.77	.82	.96	1.10	1.22	1.34	1.38	1.40	1.40	1.44	1.47	1.49	1.50	1.52	1.58	*1.64*	*1.68*
2.74	2.17	1.94	2.13	3.62	4.51	3.79	3.25	3.30	4.30	5.34	6.68	6.14	5.24	4.30	4.52	*4.75*	*4.35*
6.71	9.19	11.21	11.62	13.30	14.88	13.55	14.57	16.98	18.72	18.01	19.78	20.47	14.72	14.56	15.52	*167.00*	*17.90*
331.47	354.72	378.14	380.15	385.04	373.27	374.58	377.18	483.39	578.41	581.94	630.32	665.85	673.86	679.73	693.40	*755.00*	*765.00*
11.1	10.6	12.5	15.1	14.1	17.3	17.6	25.7	11.9	10.5	10.9	12.8	14.1	13.9	12.8	17.6		
.61	.60	.66	.80	.76	.92	1.06	1.71	.76	.66	.69	.72	.74	.70	.67	.88		
4.2%	4.0%	3.5%	3.3%	3.4%	2.7%	3.1%	4.5%	5.1%	5.1%	5.1%	4.8%	4.4%	4.5%	4.2%	4.2%		

Bold figures are Value Line estimates

8044.0	7556.0	8521.0	12737	12286	11860	11499	7669.0	7517.0	7447.0	*7700*	*7900*
940.0	465.0	1009.0	1456.0	1536.0	1541.0	1583.0	1603.0	1902.0	1449.0	*1605*	*1775*
31.8%	21.8%	22.0%	31.0%	26.2%	23.1%	33.0%	22.5%	25.4%	24.2%	*20.5%*	*20.5%*
.1%	9.5%	3.5%	4.0%	4.1%	3.7%	2.8%	1.6%	1.6%	1.9%	*2.0%*	*2.0%*
57.1%	55.2%	59.0%	61.9%	64.1%	62.3%	58.0%	65.2%	64.3%	64.8%	*61.0%*	*59.0%*
40.5%	42.5%	39.8%	37.2%	35.9%	37.7%	42.0%	34.8%	35.7%	35.2%	*39.0%*	*41.0%*
12529	12940	20621	29071	29205	33058	32484	28482	27707	30608	*33050*	*33375*
12416	13174	20858	27266	30032	33087	34597	30382	30074	33092	*35475*	*37525*
9.2%	5.2%	6.1%	6.5%	7.0%	6.2%	6.5%	7.1%	8.4%	6.2%	*6.5%*	*6.5%*
17.5%	8.0%	11.9%	13.1%	14.7%	12.4%	11.6%	16.2%	19.2%	13.5%	*12.5%*	*13.0%*
18.2%	8.1%	12.0%	13.3%	14.6%	12.4%	11.6%	16.2%	19.2%	13.5%	*12.5%*	*13.0%*
8.5%	NMF	5.2%	6.4%	6.7%	5.3%	4.5%	6.0%	8.8%	3.5%	*3.5%*	*3.5%*
54%	115%	58%	52%	54%	57%	61%	63%	54%	74%	*74%*	*72%*

Revenues per sh		*11.00*
"Cash Flow" per sh		*4.75*
Earnings per sh [A]		*2.75*
Div'd Decl'd per sh [B] ■		*1.80*
Cap'l Spending per sh		*3.25*
Book Value per sh [C]		*20.75*
Common Shs Outst'g [D]		*780.00*
Avg Ann'l P/E Ratio		*14.0*
Relative P/E Ratio		*.80*
Avg Ann'l Div'd Yield		*4.6%*
Revenues ($mill)		*8600*
Net Profit ($mill)		*2125*
Income Tax Rate		*20.5%*
AFUDC % to Net Profit		*1.0%*
Long-Term Debt Ratio		*56.0%*
Common Equity Ratio		*44.0%*
Total Capital ($mill)		*36900*
Net Plant ($mill)		*41700*
Return on Total Cap'l		*7.0%*
Return on Shr. Equity		*13.0%*
Return on Com Equity [E]		*13.0%*
Retained to Com Eq		*4.5%*
All Div'ds to Net Prof		*66%*

CAPITAL STRUCTURE as of 3/31/18
Total Debt $21921 mill. **Due in 5 Yrs** $5937 mill.
LT Debt $20214 mill. **LT Interest** $826 mill.
Incl. 23 mill. units 7.75%, $25 liq. value; 82,000 units 8.23%, $1000 face value.
(LT interest earned: 3.2x)

Leases, Uncapitalized Annual rentals $32 mill.
Pension Assets-12/17 $11978 mill.
Oblig $12507 mill.

Pfd Stock None
Common Stock 699,042,874 shs.
as of 4/25/18
MARKET CAP: $19 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.5	-.5	-1.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	321	339	336

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-4.5%	-11.5%	*Nil*
"Cash Flow"	-1.0%	-2.0%	*3.5%*
Earnings	.5%	-.5%	*2.0%*
Dividends	3.5%	1.5%	*2.5%*
Book Value	1.0%	-3.5%	*5.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	2230	1781	1878	1780	7669.0
2016	2011	1785	1889	1832	7517.0
2017	1951	1725	1845	1926	7447.0
2018	2126	*1800*	*1874*	*1900*	*7700*
2019	*2150*	*1850*	*1950*	*1950*	*7900*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.82	.37	.59	.60	2.37
2016	.71	.71	.69	.68	2.79
2017	.59	.43	.51	.58	2.11
2018	.65	*.50*	*.57*	*.53*	*2.25*
2019	*.68*	*.52*	*.60*	*.55*	*2.35*

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.368	.373	.373	.373	1.49
2015	.372	.372	.373	.378	1.50
2016	.378	.38	.38	.38	1.52
2017	.38	.395	.395	.395	1.57
2018	.395	.41			

BUSINESS: PPL Corporation (formerly PP&L Resources, Inc.) is a holding company for PPL Electric Utilities (formerly Pennsylvania Power & Light Company), which distributes electricity to 1.4 million customers in eastern & central PA. Acq'd Kentucky Utilities and Louisville Gas and Electric (1.2 million customers) 11/10. Has electric distribution sub. in U.K. (7.8 million customers). Sold gas distribution subsidiary in '08. Spun off power generating subsidiary in '15. The company no longer breaks out data on electric operating statistics. Fuel costs: 19% of revs. '17 reported deprec. rate: 2.7%. Has 12,500 employees. Chairman, President & CEO: William H. Spence. Inc.: PA. Address: Two North Ninth St., Allentown, PA 18101-1179. Tel.: 800-345-3085. Internet: www.pplweb.com.

Investors' concerns about PPL Corporation's utility operations in the United Kingdom are hurting the price of PPL's stock. The share price sank 12% in 2017—a good year for most utility equities—and has retreated another 11% so far this year. The regulatory commission in the U.K. is considering changes that would reduce the allowed return on equity for electric companies beginning in 2023. There is a separate worry that utilities in the U.K. will be nationalized if the Labour Party goes into power. And currency exchange rates are another source of uncertainty, although we note that PPL has hedged its exposure for 2018 and 2019 and half its exposure for 2020. The effects of these hedges reduced first-quarter earnings by $0.09 a share. We *included* this in our earnings presentation because these items are ongoing, even though management excludes them from its 2018 earnings guidance of $2.20-$2.40 a share.

The prospects for PPL's domestic utilities are less unclear. The utility in Pennsylvania is benefiting from increased income from electric transmission, and the utilities in Kentucky are benefiting from rate increases granted in mid-2017. The solid performance from these operations should help lift earnings modestly in 2019.

Dividend growth might be slowing. The board of directors raised the annual payout by $0.06 a share (3.8%) this year, effective with the April payment. However, PPL is no longer stating its expectation of 4% dividend growth through 2020—merely an expectation of dividend growth of some kind. We note that the new federal tax law will hurt cash flow and necessitated equity financing. PPL has executed a forward sale of 55 million common shares at $27.

The utilities in Kentucky are awaiting a ruling on their advanced metering proposal. If this is approved, they would spend $313 million to install 1.3 million meters over a three-year period. A decision is expected soon.

This untimely stock has one of the highest yields of any electric utility issue. We think the equity is attractive for income-oriented investors who are willing to bear with the risks surrounding the company's U.K. operations. Total return potential to 2021-2023 is respectable.

Paul E. Debbas, CFA *May 18, 2018*

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	10
Earnings Predictability	70

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(A) Dil. EPS. Excl. nonrec. gain (losses): '07, (12¢); '10, (8¢); '11, 8¢; '13, (62¢); gains (losses) on disc. ops.: '07, 19¢; '08, 3¢; '09, (10¢); '10, (4¢); '12, (1¢); '14, 23¢; '15, ($1.36). '15 EPS don't sum to rounding. Next earnings report due early Aug. **(B)** Div'ds historically paid in early Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. **(C)** Incl. intang. In '17: $7.87/sh. **(D)** In mill., adj. for split. **(E)** Rate base: Fair val. Rate all'd on com. eq. in PA in '16: none spec.; in KY in '17: 9.7%; earned on avg. com. eq., '17: 10.9%. Regul. Climate: Avg.

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SCANA CORP. NYSE-SCG

RECENT PRICE **35.24** | P/E RATIO **9.7** (Trailing: 8.4 / Median: 14.0) | RELATIVE P/E RATIO **0.54** | DIV'D YLD **Nil-7.0%** | **VALUE LINE**

TIMELINESS 4 Lowered 5/4/18
SAFETY 3 Lowered 10/13/17
TECHNICAL 3 Raised 4/20/18
BETA .70 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+30%)	8%
Low	35	(Nil)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	3	0	0	3	0	0	5	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	212	225	207
to Sell	247	224	222
Hld's(000)	109383	109139	100765

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
High:	45.5	44.1	38.6	42.0	45.5	50.3	54.4	63.4	65.6	76.4	74.1	49.4								
Low:	32.9	27.8	26.0	34.2	34.6	43.3	44.7	45.6	49.9	59.5	37.1	34.8								
	26.65	30.85	34.53	41.66	39.11	39.61	45.16	34.35	36.10	33.95	31.63	31.88	34.70	30.65	29.58	30.82	*30.75*	*31.45*	Revenues per sh	*33.50*
	4.56	4.95	5.28	7.43	5.68	5.73	5.86	5.63	5.91	6.01	6.30	6.53	6.91	6.70	7.28	7.35	*7.00*	*7.25*	"Cash Flow" per sh	*8.25*
	2.38	2.50	2.67	2.78	2.59	2.74	2.95	2.85	2.98	2.97	3.15	3.39	3.79	3.81	4.16	4.20	*3.65*	*3.70*	Earnings per sh A	*4.00*
	1.30	1.38	1.46	1.56	1.68	1.76	1.84	1.88	1.90	1.94	1.98	2.03	2.10	2.18	2.30	2.45	*.61*	*Nil*	Div'd Decl'd per sh B ■ †	*1.50*
	6.41	6.94	4.86	3.38	4.52	6.21	7.68	7.41	6.87	6.81	8.16	7.84	7.65	8.07	11.05	8.57	*6.20*	*6.05*	Cap'l Spending per sh	*6.50*
	19.64	20.82	21.78	23.35	24.39	25.37	25.85	27.63	29.05	29.94	31.47	33.08	34.95	38.09	40.06	36.75	*39.80*	*43.55*	Book Value per sh C	*52.50*
	110.83	110.74	112.52	114.67	116.67	116.67	117.78	123.34	127.45	129.88	132.01	141.00	142.70	142.90	142.90	143.00	*143.00*	*143.00*	Common Shs Outst'g D	*143.00*
	12.2	13.0	13.6	14.4	15.4	15.0	12.7	11.6	12.9	13.7	14.8	14.4	13.7	14.7	16.8	14.5			Avg Ann'l P/E Ratio	*10.5*
	.67	.74	.72	.77	.83	.80	.76	.77	.82	.86	.94	.81	.72	.74	.88	.73			Relative P/E Ratio	*.60*
	4.5%	4.2%	4.0%	3.9%	4.2%	4.3%	4.9%	5.7%	4.9%	4.8%	4.2%	4.2%	4.1%	3.9%	3.3%	4.0%			Avg Ann'l Div'd Yield	*3.5%*
	5319.0	4237.0	4601.0	4409.0	4176.0	4495.0	4951.0	4380.0	4227.0	4407.0	*4400*	*4500*	Revenues ($mill)	*4800*
	353.0	357.0	376.0	387.0	420.0	471.0	538.0	544.0	595.0	601.0	*525*	*535*	Net Profit ($mill)	*590*
	35.4%	32.0%	29.8%	30.3%	30.2%	32.1%	31.6%	31.8%	31.3%	32.2%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
	8.5%	14.3%	8.0%	5.4%	7.6%	8.7%	9.1%	7.7%	8.1%	6.8%	*5.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
	58.0%	56.8%	52.9%	54.3%	54.4%	53.6%	52.6%	51.9%	53.1%	52.9%	*54.0%*	*50.5%*	Long-Term Debt Ratio	*47.5%*
	40.5%	43.2%	47.1%	45.7%	45.6%	46.4%	47.4%	48.1%	46.9%	47.1%	*46.0%*	*49.5%*	Common Equity Ratio	*52.5%*
	7519.0	7891.0	7854.0	8511.0	9103.0	10059	10518	11325	12198	11161	*12400*	*12550*	Total Capital ($mill)	*14300*
	8305.0	9009.0	9662.0	10047	10896	11643	12232	13425	14324	10648	*11050*	*11425*	Net Plant ($mill)	*12500*
	6.2%	6.1%	6.5%	6.2%	6.3%	6.2%	6.6%	6.2%	6.3%	7.0%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
	11.2%	10.5%	10.2%	10.0%	10.1%	10.1%	10.8%	10.0%	10.4%	11.4%	*9.0%*	*8.5%*	Return on Shr. Equity	*8.0%*
	11.4%	10.2%	10.2%	10.0%	10.1%	10.1%	10.8%	10.0%	10.4%	11.4%	*9.0%*	*8.5%*	Return on Com Equity E	*8.0%*
	4.4%	3.6%	3.8%	3.6%	3.9%	4.1%	4.9%	4.3%	4.7%	4.9%	*7.5%*	*8.5%*	Retained to Com Eq	*5.0%*
	62%	66%	63%	64%	61%	60%	55%	57%	55%	57%	*17%*	*Nil*	All Div'ds to Net Prof	*36%*

Bold figures are Value Line estimates

CAPITAL STRUCTURE as of 3/31/18
Total Debt $6976 mill. **Due in 5 Yrs** $2116 mill.
LT Debt $6001 mill. **LT Interest** $365 mill.
(LT interest earned: 3.3x)

Leases, Uncapitalized Annual rentals $34 mill.
Pension Assets-12/17 $849.6 mill.
Oblig $933.2 mill.

Pfd Stock None

Common Stock 142,628,142 shs.
as of 4/24/18
MARKET CAP: $5.0 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.9	+1.6	NA
Avg. Indust. Use (MWH)	NA	7991	NA
Avg. Indust. Revs. per KWH (¢)	NA	7.07	NA
Capacity at Yearend (Mw)	5234	5233	5233
Peak Load, Summer (Mw)	4970	4807	4701
Annual Load Factor (%)	NA	58.5	NA
% Change Customers (yr-end)	+1.5	+1.6	+1.3
Fixed Charge Cov. (%)	323	319	313

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-3.0%	-2.0%	*1.5%*
"Cash Flow"	1.0%	3.0%	*2.5%*
Earnings	4.0%	6.0%	*Nil*
Dividends	3.5%	3.5%	*-7.0%*
Book Value	4.5%	5.0%	*5.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1389	967	1068	956	4380.0
2016	1172	905	1093	1057	4227.0
2017	1173	1001	1076	1157	4407.0
2018	1180	*1020*	*1100*	*1100*	*4400*
2019	*1225*	*1025*	*1125*	*1125*	*4500*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.39	.69	1.04	.69	3.81
2016	1.23	.74	1.32	.87	4.16
2017	1.19	.85	1.15	1.01	4.20
2018	1.18	*.67*	*1.05*	*.75*	*3.65*
2019	*1.20*	*.70*	*1.05*	*.75*	*3.70*

QUARTERLY DIVIDENDS PAID B ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.5075	.525	.525	.525	2.08
2015	.525	.545	.545	.545	2.16
2016	.545	.575	.575	.575	2.27
2017	.575	.6125	.6125	.6125	2.41
2018	.6125	.6125			

% TOT. RETURN 4/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-41.8	9.5
3 yr.	-21.6	25.8
5 yr.	-16.9	68.8

Target Price Range 2021 | 2022 | 2023

BUSINESS: SCANA Corporation is a holding company for South Carolina Electric & Gas Company, which supplies electricity to 723,000 customers in central, southern, and southwestern South Carolina. Supplies gas service to 1.4 million customers in North Carolina, South Carolina, and Georgia. Electric revenue breakdown: residential, 46%; commercial, 33%; industrial, 17%; other, 4%. Generating sources: coal, 38%; gas & oil, 27%; nuclear, 23%; hydro & other, 4%; purchased, 8%. Fuel costs: 40% of revenues. '17 reported depreciation rate: 2.6%. Has 5,200 employees. CEO: Jimmy Addison. Incorporated: South Carolina. Address: 100 SCANA Parkway, Cayce, South Carolina 29033. Telephone: 803-217-9000. Internet: www.scana.com.

Wall Street is not optimistic that the acquisition of SCANA by Dominion Energy will be completed. SCANA stockholders would receive .669 of a share of Dominion Energy (valued at $42.24) for each of their shares. The transaction requires the approval of SCANA's stockholders, the regulators in South Carolina and North Carolina, and the Federal Regulatory Commission. South Carolina Electric & Gas has been collecting money from its customers for a nuclear construction project that it canceled due to extensive delays and cost overruns. It believes it is entitled to keep these monies under the state's Base Load Review Act (BLRA), but customers and lawmakers disagree. Dominion Energy stated it would pay $1.3 billion to South Carolina Electric & Gas' electric customers and forgo recovery of $1.7 billion of nuclear costs, but will walk away from the deal if legislators and/or regulators in South Carolina insist on changes that would reduce its economic value. The recent price of SCANA stock is 17% below the value of the offer, so the stock is not trading on the basis of the buyout agreement.

The board of directors postponed a decision on the dividend. This stems from the significant uncertainties the company is facing. The board will make a decision closer to the record date of June 11th. We think the most likely outcome is suspension of the payout, so we are showing a split dividend at the top of the page. Accordingly, income-oriented investors should not be tempted by the seemingly attractive dividend yield.

SCANA is facing other concerns. The staff of the South Carolina commission has proposed a $445 million rate reduction. The state attorney general has questioned whether SCE&G complied with the terms of the BLRA. The cancelation prompted the company to take a $690 million after-tax writedown last year, and as of yearend 2017, $4 billion of unrecovered costs remained on the balance sheet. And the federal government has requested documents relating to the project.

We advise investors to avoid this stock. There is too much risk here. Note that we have lowered the company's Financial Strength rating from B+ to B.

Paul E. Debbas, CFA *May 18, 2018*

Company's Financial Strength	B
Stock's Price Stability	75
Price Growth Persistence	35
Earnings Predictability	100

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(A) Diluted earnings. Excl. nonrecurring gains (losses): '02, ($3.72); '03, 31¢; '04, (23¢); '05, 3¢; '06, 9¢; '15, $1.41; '17, ($5.03). Next earnings report due late July. **(B)** Div'ds historically paid in early Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. **(C)** Incl. intangibles. In '17: $39.02/sh. **(D)** In millions. **(E)** Rate base: Net original cost. Rate allowed on com. eq. in SC: 10.25% elec. in '13, 10.25% gas in '05; in NC: 9.7% in '16; earned on avg. com. eq., '17: 10.3%. Regulatory Climate: Above Average.

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SOUTHERN COMPANY NYSE-SO

RECENT PRICE **44.15** | P/E RATIO **15.2** (Trailing: 12.9 / Median: 16.0) | RELATIVE P/E RATIO **0.85** | DIV'D YLD **5.5%** | **VALUE LINE**

TIMELINESS 3 Raised 3/2/18
SAFETY 2 Lowered 2/21/14
TECHNICAL 4 Raised 5/18/18
BETA .55 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+45%)	*14%*
Low	45	(Nil)	*6%*

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	1	1	0	4	2	1	2	1	4	0
to Sell	0	1	0	4	2	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	553	498	480
to Sell	494	514	450
Hld's(000)	599382	603476	568350

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	39.3	40.6	37.6	38.6	46.7	48.6	48.7	51.3	53.2	54.6	53.5	48.1						
Low:	33.2	29.8	26.5	30.8	35.7	41.8	40.0	40.3	41.4	46.0	46.7	42.4						

LEGENDS
0.62 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2021 | 2022 | 2023

% TOT. RETURN 4/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.8	9.5
3 yr.	19.8	25.8
5 yr.	20.8	68.8

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
	14.73	15.31	16.05	18.28	19.24	20.12	22.04	19.21	20.70	20.41	19.06	19.26	20.34	19.18	20.09	22.86	*23.80*	*24.50*	Revenues per sh	*26.75*
	3.46	3.53	3.65	4.03	4.01	4.22	4.43	4.43	4.51	4.91	5.18	5.27	5.28	5.47	5.69	6.64	*6.35*	*6.60*	"Cash Flow" per sh	*7.50*
	1.85	1.97	2.06	2.13	2.10	2.28	2.25	2.32	2.36	2.55	2.67	2.70	2.77	2.84	2.83	3.21	*2.90*	*3.05*	Earnings per sh [A]	*3.50*
	1.36	1.39	1.42	1.48	1.54	1.60	1.66	1.73	1.80	1.87	1.94	2.01	2.08	2.15	2.22	2.30	*2.38*	*2.46*	Div'd Decl'd per sh [B] ■ †	*2.70*
	3.79	2.72	2.85	3.20	4.01	4.65	5.10	5.70	4.85	5.23	5.54	6.16	6.58	6.22	7.38	7.37	*8.45*	*7.15*	Cap'l Spending per sh	*7.25*
	12.16	13.13	13.86	14.42	15.24	16.23	17.08	18.15	19.21	20.32	21.09	21.43	21.98	22.59	25.00	23.98	*24.95*	*26.05*	Book Value per sh [C]	*29.75*
	716.40	734.83	741.50	741.45	746.27	763.10	777.19	819.65	843.34	865.13	867.77	887.09	907.78	911.72	990.39	1007.6	*1030.0*	*1050.0*	Common Shs Outst'g [D]	*1110.0*
	14.6	14.8	14.7	15.9	16.2	16.0	16.1	13.5	14.9	15.8	17.0	16.2	16.0	15.8	17.8	15.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.5*
	.80	.84	.78	.85	.87	.85	.97	.90	.95	.99	1.08	.91	.84	.80	.93	.78			Relative P/E Ratio	*.85*
	5.0%	4.7%	4.7%	4.4%	4.5%	4.4%	4.6%	5.5%	5.1%	4.6%	4.3%	4.6%	4.7%	4.8%	4.4%	4.6%			Avg Ann'l Div'd Yield	*4.9%*
	17127	15743	17456	17657	16537	17087	18467	17489	19896	23031	*24500*	*25700*	Revenues ($mill)	*29750*
	1807.0	1910.0	2040.0	2268.0	2415.0	2439.0	2567.0	2647.0	2757.0	3269.0	*3035*	*3285*	Net Profit ($mill)	*4065*
	33.6%	31.9%	33.5%	35.0%	35.6%	34.8%	33.8%	33.4%	28.5%	25.2%	*11.0%*	*11.0%*	Income Tax Rate	*11.0%*
	12.3%	14.9%	13.7%	10.2%	9.4%	11.6%	13.9%	13.2%	11.9%	7.6%	*5.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
	53.9%	53.2%	51.2%	50.0%	49.9%	51.5%	49.5%	52.8%	61.5%	64.5%	*62.5%*	*61.5%*	Long-Term Debt Ratio	*58.5%*
	42.6%	43.6%	45.7%	47.1%	47.3%	45.8%	47.3%	44.0%	35.7%	35.0%	*37.0%*	*38.0%*	Common Equity Ratio	*41.5%*
	31174	34091	35438	37307	38653	41483	42142	46788	69359	68953	*69825*	*71925*	Total Capital ($mill)	*80000*
	35878	39230	42002	45010	48390	51208	54868	61114	78446	79872	*84975*	*88725*	Net Plant ($mill)	*95500*
	7.1%	6.9%	7.0%	7.2%	7.3%	6.8%	7.1%	6.6%	4.9%	5.9%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
	12.6%	12.0%	11.8%	12.2%	12.5%	12.1%	12.1%	12.0%	10.3%	13.3%	*11.5%*	*12.0%*	Return on Shr. Equity	*12.0%*
	13.1%	12.4%	12.2%	12.5%	12.8%	12.5%	12.5%	12.6%	11.0%	13.4%	*11.5%*	*12.0%*	Return on Com Equity [E]	*12.0%*
	3.5%	3.2%	3.0%	3.4%	3.6%	3.2%	3.2%	3.1%	2.5%	3.9%	*2.0%*	*2.5%*	Retained to Com Eq	*3.0%*
	74%	75%	77%	73%	73%	75%	75%	76%	78%	72%	*80%*	*78%*	All Div'ds to Net Prof	*74%*

CAPITAL STRUCTURE as of 3/31/18
Total Debt $51952 mill. **Due in 5 Yrs** $19863 mill.
LT Debt $44446 mill. **LT Interest** $1556 mill.
(LT interest earned: 3.5x)

Leases, Uncapitalized Annual rentals $149 mill.
Pension Assets-12/17 $12992 mill.
Oblig $13808 mill.
Pfd Stock $324 mill. **Pfd Div'd** $17 mill.
Incl. 10 mill. shs. 5% cum. pfd. ($25 stated value); 334,210 shs. 4.4%-5.25% cum. pfd. ($100 par).

Common Stock 1,011,624,620 shs.
MARKET CAP: $45 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.7	+.2	-2.6
Avg. Indust. Use (MWH)	3371	3105	3016
Avg. Indust. Revs. per KWH (¢)	5.88	6.01	6.18
Capacity at Yearend (Mw)	44223	46291	46936
Peak Load, Summer (Mw) [F]	36794	35781	34874
Annual Load Factor (%)	59.9	61.5	61.4
% Change Customers (yr-end)	+.9	+1.0	+1.0
Fixed Charge Cov. (%)	433	330	318

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	1.0%	.5%	*4.5%*
"Cash Flow"	4.0%	4.0%	*4.0%*
Earnings	3.0%	3.0%	*3.0%*
Dividends	4.0%	3.5%	*3.5%*
Book Value	4.5%	3.5%	*3.5%*

QUARTERLY REVENUES (mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	4183	4337	5401	3568	17489
2016	3992	4459	6264	5181	19896
2017	5771	5430	6201	5629	23031
2018	6372	*5728*	*6500*	*5900*	*24500*
2019	*6600*	*6000*	*6900*	*6200*	*25700*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.56	.71	1.16	.42	2.84
2016	.57	.71	1.22	.33	2.83
2017	.73	.73	1.08	.67	3.21
2018	.93	*.65*	*.90*	*.42*	*2.90*
2019	*.90*	*.70*	*1.00*	*.45*	*3.05*

QUARTERLY DIVIDENDS PAID [B] ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.5075	.525	.525	.525	2.08
2015	.525	.5425	.5425	.5425	2.15
2016	.5425	.56	.56	.56	2.22
2017	.56	.58	.58	.58	2.30
2018	.58	.60			

BUSINESS: The Southern Company, through its subs., supplies electricity to 4.6 million customers in GA, AL, FL, and MS. Also has a competitive generation business. Acq'd AGL Resources (renamed Southern Company Gas, 4.5 mill. customers in GA, FL, NJ, IL, VA, & TN) 7/16. Electric rev. breakdown: residential, 37%; commercial, 31%; industrial, 18%; other, 14%. Retail revs. by state: GA, 49%; AL, 35%; FL, 9%; MS, 7%. Generating sources: gas & oil, 42%; coal, 27%; nuclear, 15%; other, 7%; purchased, 9%. Fuel costs: 32% of revs. '17 reported depr. rate (utility): 2.9%. Has 31,300 employees. Chairman, President and CEO: Thomas A. Fanning. Inc.: DE. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, GA 30308. Tel.: 404-506-0747. Internet: www.southerncompany.com.

Southern Company's Georgia Power subsidiary is building two units at the site of its Vogtle nuclear station. As of March 31st, the project was slightly more than halfway complete, with expected in-service dates of November of 2021 and 2022. After delays and cost overruns, the utility's 45.7% share of the project will cost an estimated $8.8 billion. Of this amount, $1.5 billion will be offset by a guarantee from Toshiba, the parent company of Westinghouse (the original contractor that filed for bankruptcy protection).

The company has significant equity needs. Southern estimates that it will require $7 billion over the next five years. Some of this will likely be offset by the proceeds from asset sales and, perhaps, the use of third-party tax-equity financing for renewable-energy projects. Partly because the share count will be higher than we estimated three months ago, we lowered our 2018 and 2019 share-earnings estimates by $0.10 each year. Management's share-net guidance for this year is for a decline to $2.80-$2.95, due in part to the situation at Vogtle and the negative effect of tax reform. However, Southern excludes certain items that we include in our earnings presentation. These added a net of $0.05 to share profits in the first quarter.

Southern is selling two of its gas utilities. The company will receive $1.7 billion ($200 million above book value) for Elizabethtown Gas and Elkton Gas. The closing is expected by the end of the third quarter. The proceeds will offset past equity needs.

The board of directors increased the quarterly dividend by $0.02 a share (3.4%) in the second quarter. We project the same increase each year over the 3- to 5-year period.

This stock has one of the highest dividend yields in the electric utility industry. This is nearly two percentage points above the industry average. Total return potential to 2021-2023 is also above average for a utility. The stock has not performed well in recent years due to the cost overruns at Vogtle and a plant in Mississippi that was supposed to run on gasified coal, but will run as a gas-fired facility. Investors must be willing to accept some construction risk at Vogtle, however.

Paul E. Debbas, CFA *May 18, 2018*

(A) Dil. EPS. Excl. nonrec. gain (losses): '03, 6¢; '09, (25¢); '13, (83¢); '14, (59¢); '15, (25¢); '16, (28¢); '17, ($2.37). '15 EPS don't sum due to rounding. Next egs. report due early Aug. **(B)** Div'ds paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. † Shrhldr. invest. plan avail. **(C)** Incl. def'd chgs. In '17: $16.36/sh. **(D)** In mill. **(E)** Rate base: AL, MS, fair value; FL, GA, orig. cost. All'd return on com. eq. (blended): 12.5%; earn. on avg. com. eq., '17: 12.5%. Regul. Climate: GA, AL Above Avg.; MS, FL Avg. **(F)** Winter peak in '15.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	100

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SEMPRA ENERGY NYSE-SRE

RECENT PRICE **112.60** | P/E RATIO **20.3** (Trailing: 24.3 Median: 17.0) | RELATIVE P/E RATIO **1.08** | DIV'D YLD **3.2%** | **VALUE LINE**

TIMELINESS 4 Lowered 3/30/18
SAFETY 2 Raised 7/29/16
TECHNICAL 4 Raised 4/27/18
BETA .80 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	160	(+40%)	*12%*
Low	120	(+5%)	*5%*

Insider Decisions

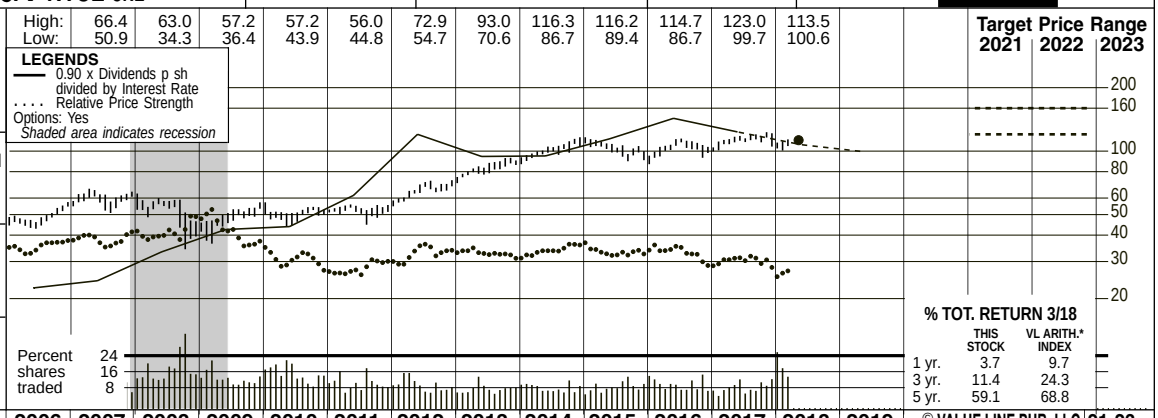
	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	7	8
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	268	282	271
to Sell	259	244	214
Hld's(000)	223635	223050	209265

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
High:	66.4	63.0	57.2	57.2	56.0	72.9	93.0	116.3	116.2	114.7	123.0	113.5								
Low:	50.9	34.3	36.4	43.9	44.8	54.7	70.6	86.7	89.4	86.7	99.7	100.6								
	29.38	34.81	40.18	45.64	44.89	43.79	44.21	32.88	37.44	41.83	39.80	43.18	44.80	41.20	40.71	44.59	*40.15*	*41.95*	Revenues per sh	*46.00*
	5.71	5.56	6.58	5.96	6.74	6.93	7.40	7.94	7.76	8.58	8.92	8.87	9.41	10.32	9.50	10.57	*11.00*	*11.75*	"Cash Flow" per sh	*14.25*
	2.79	3.01	3.93	3.52	4.23	4.26	4.43	4.78	4.02	4.47	4.35	4.22	4.63	5.23	4.24	4.63	*5.50*	*5.95*	Earnings per sh [A]	*7.75*
	1.00	1.00	1.00	1.16	1.20	1.24	1.37	1.56	1.56	1.92	2.40	2.52	2.64	2.80	3.02	3.29	*3.58*	*3.86*	Div'd Decl'd per sh [B] ■	*4.90*
	5.92	4.63	4.62	5.46	7.28	7.70	8.47	7.76	8.58	11.85	12.20	10.52	12.68	12.71	16.85	15.71	*9.50*	*9.55*	Cap'l Spending per sh	*9.25*
	13.79	17.17	20.78	23.95	28.66	31.87	32.75	36.54	37.54	41.00	42.42	45.03	45.98	47.56	51.77	50.41	*58.20*	*60.25*	Book Value per sh [C]	*71.00*
	204.91	226.60	234.18	257.19	262.01	261.21	243.32	246.51	240.45	239.93	242.37	244.46	246.33	248.30	250.15	251.36	*279.00*	*280.00*	Common Shs Outst'g [D]	*296.00*
	8.2	9.0	8.6	11.8	11.5	14.0	11.8	10.1	12.6	11.8	14.9	19.7	21.9	19.7	24.4	24.3			Avg Ann'l P/E Ratio	*18.0*
	.45	.51	.45	.63	.62	.74	.71	.67	.80	.74	.95	1.11	1.15	.99	1.28	1.22			Relative P/E Ratio	*1.00*
	4.4%	3.7%	2.9%	2.8%	2.5%	2.1%	2.6%	3.2%	3.1%	3.6%	3.7%	3.0%	2.6%	2.7%	2.9%	2.9%			Avg Ann'l Div'd Yield	*3.5%*
	10758	8106.0	9003.0	10036	9647.0	10557	11035	10231	10183	11207	*11200*	*11750*	Revenues ($mill)	*13600*
	1123.0	1193.0	1008.0	1088.0	1079.0	1060.0	1162.0	1314.0	1065.0	1169.0	*1740*	*1895*	Net Profit ($mill)	*2440*
	29.2%	30.5%	26.5%	25.3%	18.2%	26.5%	19.7%	19.2%	14.4%	24.5%	*20.5%*	*20.0%*	Income Tax Rate	*19.0%*
	13.2%	10.6%	11.3%	15.2%	17.2%	11.2%	14.4%	15.3%	22.2%	21.9%	*14.0%*	*13.0%*	AFUDC % to Net Profit	*10.0%*
	44.5%	44.8%	49.4%	50.4%	52.8%	50.5%	51.7%	52.6%	52.7%	56.4%	*52.5%*	*53.5%*	Long-Term Debt Ratio	*55.0%*
	54.2%	54.1%	49.6%	49.2%	46.7%	49.4%	48.2%	47.3%	47.3%	43.5%	*42.5%*	*42.0%*	Common Equity Ratio	*45.0%*
	14692	16646	18186	20015	22002	22281	23513	24963	27400	29135	*38000*	*39975*	Total Capital ($mill)	*46700*
	16865	18281	19876	23572	25191	25460	25902	28039	32931	36503	*37600*	*38625*	Net Plant ($mill)	*41400*
	8.5%	8.3%	6.8%	6.7%	6.1%	6.0%	6.1%	6.4%	5.0%	5.1%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
	13.8%	13.0%	10.9%	10.9%	10.4%	9.6%	10.2%	11.1%	8.2%	9.2%	*9.0%*	*9.5%*	Return on Shr. Equity	*11.0%*
	14.0%	13.1%	11.1%	11.0%	10.4%	9.6%	10.3%	11.1%	8.2%	9.2%	*9.5%*	*10.0%*	Return on Com Equity [E]	*11.0%*
	9.7%	9.3%	7.0%	6.5%	5.1%	4.1%	5.0%	5.8%	2.9%	3.3%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
	31%	29%	37%	41%	52%	58%	52%	48%	65%	65%	*65%*	*67%*	All Div'ds to Net Prof	*63%*

Bold figures are Value Line estimates



CAPITAL STRUCTURE as of 12/31/17
Total Debt $19412 mill. **Due in 5 Yrs** $7455 mill.
LT Debt $16445 mill. **LT Interest** $686 mill.
Incl. $733 mill. capitalized leases.
(LT interest earned: 3.2x)

Leases, Uncapitalized Annual rentals $98 mill.
Pension Assets-12/17 $2659 mill.
Oblig $3859 mill.
Pfd Stock $20 mill. **Pfd Div'd** $1.2 mill.
811,073 shs. 6% cum., $25 par.
Common Stock 255,324,212 shs.
as of 2/22/18
MARKET CAP: $29 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-1.0	-3.8	-.2
Avg. Indust. Use (MWH)	4683	4785	NA
Avg. Indust. Revs. per KWH (¢)	17.58	NA	NA
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.7	+.6	+.8
Fixed Charge Cov. (%)	295	237	264

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-.5%	1.0%	*1.5%*
"Cash Flow"	4.5%	4.0%	*6.0%*
Earnings	1.5%	2.0%	*8.5%*
Dividends	9.5%	9.0%	*8.5%*
Book Value	6.0%	4.5%	*6.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	2682	2367	2481	2701	10231
2016	2622	2156	2535	2870	10183
2017	3031	2533	2679	2964	11207
2018	*3050*	*2550*	*2650*	*2950*	*11200*
2019	*3200*	*2650*	*2750*	*3150*	*11750*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1.74	1.03	.99	1.47	5.23
2016	1.61	.06	1.02	1.52	4.24
2017	1.75	1.20	.22	1.46	4.63
2018	*1.80*	*1.10*	*1.20*	*1.40*	*5.50*
2019	*1.95*	*1.20*	*1.30*	*1.50*	*5.95*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.63	.66	.66	.66	2.61
2015	.66	.70	.70	.70	2.76
2016	.70	.755	.755	.755	2.97
2017	.755	.8225	.8225	.8225	3.22
2018	.8225	.895			

BUSINESS: Sempra Energy is a holding co. for San Diego Gas & Electric Company, which sells electricity & gas mainly in San Diego County, & Southern California Gas Company, which distributes gas to most of Southern California. Owns 80% of Oncor (acq'd 3/18), which distributes electricity in Texas. Customers: 4.9 mill. electric, 6.6 mill. gas. Electric rev. breakdown: residential, 41%; commercial, 42%; industrial, 10%; other, 7%. Purchases most of its power; the rest is gas. Has nonutility subsidiaries. Sold commodities business in '10. Power costs: 34% of revs. '17 reported deprec. rates: 2.4%-5.5%. Has 20,000 employees. Chairman, President and CEO: Debra L. Reed. Inc.: CA. Address: 488 8th Ave., San Diego, CA 92101. Tel.: 619-696-2000. Internet: www.sempra.com.

Sempra Energy has completed its acquisition of Energy Future Holdings. Sempra paid $9.45 billion in cash for the company that owns 80% of Oncor, a transmission and distribution electric utility in Texas. The company financed the purchase with a combination of 65% equity and 35% debt. Sempra's 2018 earnings guidance of $5.30-$5.80 a share includes a $0.20 contribution from Oncor. We have adjusted our estimates and projections to include the acquisition, and have boosted our 2018 estimate by $0.20 a share, to $5.50. Note that Oncor will not be consolidated for financial reporting purposes due to the "ringfencing" that was required as a condition for regulatory approval.

The company's domestic utilities have a general rate case pending. Southern California Gas and San Diego Gas & Electric have adjusted their filings to reflect the effects of the new federal tax law. The latest requests are for increases of $475 million for SoCalGas and $217 million for SDG&E at the start of 2019.

The new federal tax law is negative for Sempra in the near term, but should be beneficial in the long run. The company took a noncash, nonrecurring charge of $870 million ($3.45 a share) in the fourth quarter of 2017 for the effects of the new tax law, including a plan to repatriate about $1.6 billion of undistributed foreign earnings over the next five years. The near-term losses of a liquefied natural gas project will have a lower tax shield, but will benefit from the lower tax rate once the project is operational. Sempra expects that the profit in the first full year (2020) will rise by $65 million-$75 million over the previous projection of $300 million-$350 million.

The board of directors raised the dividend, effective with the April payment. The annual increase was $0.29 a share (8.8%). We project a continuation of strong dividend growth through 2021-2023. Even so . . .

We advise investors to look elsewhere. This untimely stock is one of the few utility issues that has risen in price so far in 2018. In addition, utilities in California will face legal and regulatory risks associated with wildfires until the state makes changes that will ameliorate these risks.

Paul E. Debbas, CFA *April 27, 2018*

(A) Dil. EPS. Excl. nonrec. gains (losses): '05, 17¢; '06, (6¢); '09, (26¢); '10, ($1.05); '11, $1.15; '12, (98¢); '13, (30¢); '15, 14¢; '16, $1.23; '17, (17¢); gain (loss) from disc. ops.: '06, $1.21; '07, (10¢). '16 EPS don't sum due to change in shs. Next egs. due early May. **(B)** Div'ds pd. mid-Jan., Apr., July, Oct. ■ Div'd reinv. plan avail. **(C)** Incl. intang. In '17: $17.94/sh. **(D)** In mill. **(E)** Rate base: Net orig. cost. Rate all'd on com. eq.: SDG&E in '13: 10.3%; SoCalGas in '13: 10.1%; earned on avg. com. eq., '17: 8.8%. Regul. Climate: Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	75

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VECTREN CORP. NYSE-VVC

RECENT PRICE 61.44 | P/E RATIO 21.9 (Trailing: 23.5 Median: 17.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 3 Lowered 2/16/18
SAFETY 2 Lowered 1/5/01
TECHNICAL 3 Lowered 2/23/18
BETA .75 (1.00 = Market)

2021-23 PROJECTIONS

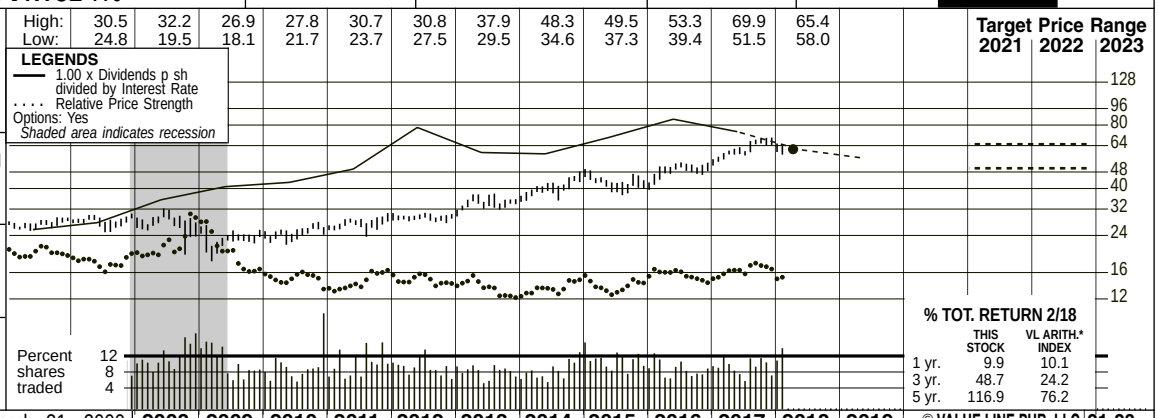
	Price	Gain	Ann'l Total Return
High	65	(+5%)	5%
Low	50	(-20%)	-1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	1	0	0	0	0
Options	0	0	0	0	0	0	0	0	11
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	153	147	140
to Sell	146	141	111
Hld's(000)	59555	60216	53161



Vectren was formed on March 31, 2000 through the merger of Indiana Energy and SIGCORP. The merger was consummated with a tax-free exchange of shares and has been accounted for as a pooling of interests. Indiana Energy common stockholders received one Vectren common share for each share held. SIGCORP stockholders exchanged each common share for 1.333 common shares of Vectren.

CAPITAL STRUCTURE as of 12/31/17
Total Debt $2088.2 mill. **Due in 5 Yrs** $644.1 mill.
LT Debt $1738.7 mill. **LT Interest** $75.0 mill.
(LT interest earned: 4.6x)

Pension Assets-12/17 $316.1 mill.
Oblig. $366.5 mill.

Pfd Stock None

Common Stock 83,040,212 shs.
as of 1/31/18

MARKET CAP: $5.1 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-2.4	+.3	-13.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1357	1360	1337
Peak Load, Summer (Mw)	1088	1096	1042
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.8	-.5
Fixed Charge Cov. (%)	428	446	363

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	1.0%	2.0%	*5.0%*
"Cash Flow"	3.5%	4.0%	*6.0%*
Earnings	4.0%	7.0%	*6.5%*
Dividends	3.0%	3.0%	*6.5%*
Book Value	3.0%	3.5%	*5.5%*

QUARTERLY REVENUES ($ mill.)[F]

Calendar	Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2015	706.2	551.0	573.5	604.0	2434.7
2016	584.8	533.7	631.0	699.0	2448.3
2017	624.5	630.7	691.2	710.9	2657.3
2018	*675*	*670*	*710*	*735*	*2790*
2019	*690*	*685*	*725*	*750*	*2850*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2015	.69	.43	.48	.79	2.39
2016	.58	.39	.74	.84	2.55
2017	.67	.45	.75	.74	2.60
2018	*.78*	*.50*	*.78*	*.79*	*2.85*
2019	*.82*	*.55*	*.84*	*.84*	*3.05*

QUARTERLY DIVIDENDS PAID [B]■†

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.360	.360	.360	.380	1.46
2015	.380	.380	.380	.400	1.54
2016	.400	.400	.400	.420	1.62
2017	.420	.420	.420	.450	1.71
2018	.450				

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
30.67	25.76	26.06	28.39	27.16	30.23	31.62	29.40	29.53	32.02	*33.40*	*33.95*	Revenues per sh	*40.70*
3.97	4.40	4.44	4.71	5.03	5.03	5.33	5.48	5.69	5.93	*6.35*	*6.60*	"Cash Flow" per sh	*8.00*
1.63	1.79	1.65	1.73	1.94	1.66	2.02	2.39	2.55	2.60	*2.85*	*3.05*	Earnings per sh [A]	*3.65*
1.31	1.35	1.37	1.39	1.41	1.43	1.46	1.54	1.62	1.71	*1.83*	*1.95*	Div'd Decl'd per sh [B]■†	*2.35*
4.83	5.33	3.39	3.92	4.45	4.77	5.43	5.76	6.54	7.26	*7.80*	*8.35*	Cap'l Spending per sh	*10.45*
16.68	17.23	17.61	17.89	18.57	18.86	19.45	20.34	21.33	22.28	*23.60*	*24.90*	Book Value per sh [C]	*29.05*
81.03	81.10	81.70	81.90	82.20	82.40	82.60	82.80	82.90	83.00	*83.50*	*84.00*	Common Shs Outst'g [D]	*86.00*
16.8	12.9	15.0	15.8	15.0	20.7	20.0	17.9	19.2	23.5	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
1.01	.86	.95	.99	.95	1.16	1.05	.90	1.01	1.15	*Value Line*		Relative P/E Ratio	*.90*
4.8%	5.9%	5.5%	5.1%	4.8%	4.2%	3.6%	3.6%	3.3%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*
2484.7	2088.9	2129.5	2325.2	2232.8	2491.2	2611.7	2434.7	2448.3	2657.3	*2790*	*2850*	Revenues ($mill)	*3500*
129.0	145.0	133.7	141.6	159.0	136.6	166.9	197.3	211.6	216.0	*240*	*255*	Net Profit ($mill)	*315*
37.1%	26.5%	35.8%	37.9%	34.2%	32.9%	32.7%	33.6%	34.8%	17.7%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
2.9%	4.1%	--	--	--	--	--	--	4.1%	4.0%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*4.0%*
48.0%	52.4%	49.9%	51.6%	50.4%	53.3%	46.7%	50.6%	47.3%	48.5%	*47.5%*	*47.0%*	Long-Term Debt Ratio	*47.0%*
52.0%	47.6%	50.1%	48.4%	49.6%	46.7%	53.3%	49.4%	52.7%	51.5%	*52.5%*	*53.0%*	Common Equity Ratio	*53.0%*
2599.5	2937.7	2874.1	3025.1	3079.5	3331.4	3013.9	3406.6	3358.0	3588.0	*3745*	*3940*	Total Capital ($mill)	*4700*
2720.3	2878.8	2955.4	3032.6	3119.6	3224.3	3439.0	4089.5	4406.8	4740.8	*4900*	*5200*	Net Plant ($mill)	*6000*
6.5%	6.3%	6.1%	6.2%	6.4%	5.4%	6.8%	7.0%	7.4%	7.0%	*7.5%*	*7.5%*	Return on Total Cap'l	*7.5%*
9.5%	10.4%	9.3%	9.7%	10.4%	8.8%	10.4%	11.7%	12.0%	11.7%	*12.0%*	*12.0%*	Return on Shr. Equity	*12.5%*
9.5%	10.4%	9.3%	9.7%	10.4%	8.8%	10.4%	11.7%	12.0%	11.7%	*12.0%*	*12.0%*	Return on Com Equity [E]	*12.5%*
2.0%	2.6%	1.6%	1.9%	2.9%	1.2%	2.9%	4.2%	4.4%	4.0%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
80%	75%	83%	80%	73%	86%	72%	65%	63%	66%	*64%*	*64%*	All Div'ds to Net Prof	*64%*

BUSINESS: Vectren Corp. is a holding company formed through the merger of Indiana Energy and SIGCORP. Supplies electricity and gas to an area nearly two-thirds of the state of Indiana. Owns gas distribution assets in Ohio. Has a customer base exceeding 1.1 million. 2017 Electricity revenues: residential, 38%; commercial, 29%; industrial, 31%; other, 2%. 2017 Gas revenues: residential, 67%; commercial, 22%; other, 11%. Nonutility operations include Infrastructure Services and Energy Services. Est'd plant age: electric, 10 years. '17 depreciation rate: 3.9%. Has about 5,500 employees. Chairman, President, & CEO: Carl L. Chapman. Incorporated: Indiana. Address: One Vectren Square, Evansville, Indiana 47708. Telephone: 812-491-4000. Internet: www.vectren.com.

Shares of Vectren have moved lower in price over the past three months. We think the equity had been particularly vulnerable due to the rich valuation the stock commanded late last year. Moreover, the company posted mixed results for the December quarter. The top line increased modestly, on a year-to-year basis. However, earnings per share of $0.74 were no match for the prior-year tally. This was due to weakness at the company's nonutility operations. A large transmission pipeline project in the back half of 2016 and the expiration of federal tax deductions related to energy efficiency savings made for an unfavorable comparison at this segment. Even so, solid earnings performance at the utility group provided support. This segment benefited from gas infrastructure replacement programs in Indiana and Ohio. This more than offset the anticipated decrease in usage from a large electric customer (that had recently completed its transition to a co-generation facility).

Prospects appear favorable for the coming years, and we expect solid growth from 2018 onward. The company's utility operations ought to further benefit from investment in gas infrastructure programs. Elsewhere, the nonutility group should also fare well, as gas utilities continue to invest in their infrastructure systems. We expect demand will be healthy, given the need to replace aging infrastructure. Still, a measure of unevenness will likely persist at this segment.

This stock is ranked to track the broader market averages for the coming six to 12 months. The equity does not stand out for long-term total return potential, either. The shares' price-to-earnings ratio remains elevated, despite the recent selloff. As a result, this issue presently trades well within our Target Price Range. The dividend yield has improved somewhat since our December review, but is not particularly compelling for a utility. In the plus column, Vectren earns high marks for Safety, Financial Strength, Price Stability, and Earnings Predictability. Moreover, volatility is below average. But all things considered, subscribers can probably find more-attractive choices elsewhere at this time.

Michael Napoli, CFA *March 16, 2018*

(A) Diluted EPS. Excl. nonrecur. gain (loss): '09, 15¢. Next egs report due early May.
(B) Div'ds historically paid in early March, June, September, and December. ■Div'd reinvest. plan avail. † Shareholder invest. plan avail. **(C)** Incl. intang. In '17, $8.56/sh. **(D)** In millions. **(E)** Electric rate base determination: fair value. Rates allowed on elect. common equity range from 10.15% to 10.4%. Regulatory Climate: Above Average. **(F)** Totals may not sum due to rounding.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	70
Earnings Predictability	80

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WEC ENERGY GROUP NYSE-WEC

RECENT PRICE **60.08** | P/E RATIO **18.2** (Trailing: 19.1 Median: 16.0) | RELATIVE P/E RATIO **0.95** | DIV'D YLD **3.7%** | **VALUE LINE**

TIMELINESS **2** Raised 3/2/18
SAFETY **1** Raised 3/23/12
TECHNICAL **3** Lowered 3/2/18
BETA .60 (1.00 = Market)

2021-23 PROJECTIONS

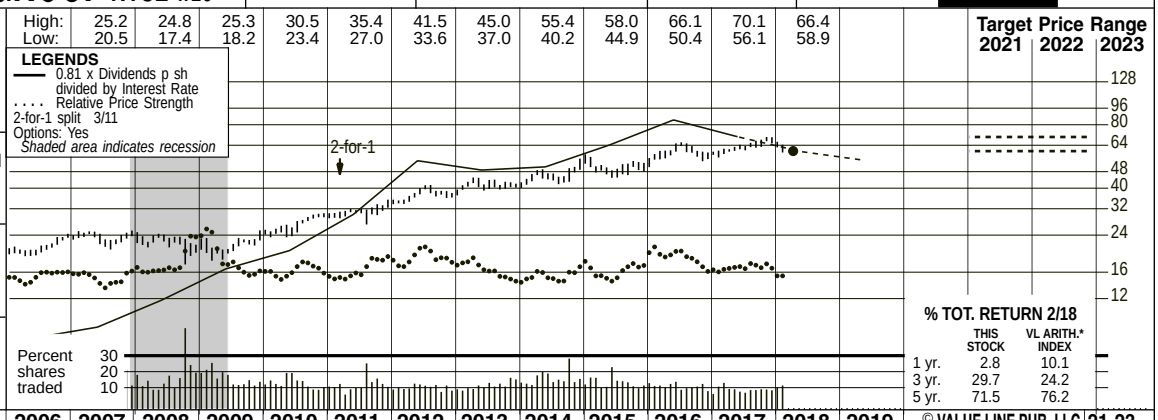
	Price	Gain	Ann'l Total Return
High	70	(+15%)	8%
Low	60	(Nil)	4%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	4	1	0	3	1	0	3	0	26
to Sell	4	2	0	4	1	0	3	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	307	308	277
to Sell	295	276	267
Hld's(000)	249489	257662	236772



Target Price Range 2021 | 2022 | 2023
128 96 80 64 48 40 32 24 16 12

% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.8	10.1
3 yr.	29.7	24.2
5 yr.	71.5	76.2

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
16.10	17.12	14.66	16.31	17.08	18.12	18.95	17.65	17.98	19.46	18.54	20.00	22.16	18.77	23.68	24.24	*24.40*	*25.35*	Revenues per sh	*28.50*
2.84	2.86	2.58	2.89	2.90	2.98	2.95	3.11	3.30	3.68	4.01	4.33	4.47	3.87	5.39	5.69	*5.95*	*6.25*	"Cash Flow" per sh	*7.25*
1.16	1.13	.93	1.28	1.32	1.42	1.52	1.60	1.92	2.18	2.35	2.51	2.59	2.34	2.96	3.14	*3.30*	*3.45*	Earnings per sh [A]	*4.25*
.40	.40	.42	.44	.46	.50	.54	.68	.80	1.04	1.20	1.45	1.56	1.74	1.98	2.08	*2.21*	*2.34*	Div'd Decl'd per sh [B] ■	*2.75*
2.54	2.95	2.85	3.40	4.17	5.28	4.86	3.50	3.41	3.60	3.09	3.04	3.26	4.01	4.51	6.21	*7.90*	*6.35*	Cap'l Spending per sh	*7.00*
9.22	9.96	10.65	11.46	12.35	13.25	14.27	15.26	16.26	17.20	18.05	18.73	19.60	27.42	28.29	29.98	*30.95*	*31.90*	Book Value per sh [C]	*35.50*
232.06	236.85	233.97	233.96	233.94	233.89	233.84	233.82	233.77	230.49	229.04	225.96	225.52	315.68	315.62	315.57	*315.60*	*315.60*	Common Shs Outst'g [D]	*315.60*
10.5	12.4	17.5	14.5	16.0	16.5	14.8	13.3	14.0	14.2	15.8	16.5	17.7	21.3	19.9	20.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.5*
.57	.71	.92	.77	.86	.88	.89	.89	.89	.89	1.01	.93	.93	1.07	1.04	.99			Relative P/E Ratio	*.85*
3.3%	2.8%	2.6%	2.4%	2.2%	2.1%	2.4%	3.2%	3.0%	3.3%	3.2%	3.5%	3.4%	3.5%	3.4%	3.3%			Avg Ann'l Div'd Yield	*4.2%*
4431.0	4127.9	4202.5	4486.4	4246.4	4519.0	4997.1	5926.1	7472.3	7648.5	*7700*	*8000*	Revenues ($mill)	*9000*
359.8	378.4	455.6	514.0	547.5	578.6	589.5	640.3	940.2	998.2	*1050*	*1100*	Net Profit ($mill)	*1320*
37.6%	36.5%	35.4%	33.9%	35.9%	36.9%	38.0%	40.4%	37.6%	37.2%	*22.5%*	*22.5%*	Income Tax Rate	*22.5%*
27.2%	25.0%	18.6%	16.8%	9.4%	4.5%	1.3%	4.5%	3.8%	1.6%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*3.0%*
54.8%	51.9%	50.6%	53.6%	51.7%	50.6%	48.5%	51.2%	50.5%	48.0%	*49.0%*	*48.0%*	Long-Term Debt Ratio	*47.5%*
44.8%	47.7%	49.0%	46.0%	48.0%	49.1%	51.2%	48.6%	49.3%	51.9%	*51.0%*	*51.5%*	Common Equity Ratio	*52.5%*
7442.0	7473.1	7764.5	8608.0	8619.3	8626.6	8636.5	17809	18118	18238	*19125*	*19500*	Total Capital ($mill)	*21300*
8517.0	9070.5	9601.5	10160	10572	10907	11258	19190	19916	21347	*23000*	*24150*	Net Plant ($mill)	*28800*
6.3%	6.4%	7.5%	7.5%	7.9%	8.1%	8.1%	4.5%	6.3%	6.6%	*6.5%*	*7.0%*	Return on Total Cap'l	*7.5%*
10.7%	10.5%	11.9%	12.9%	13.1%	13.6%	13.2%	7.4%	10.5%	10.5%	*10.5%*	*11.0%*	Return on Shr. Equity	*12.0%*
10.7%	10.6%	12.0%	12.9%	13.2%	13.6%	13.3%	7.4%	10.5%	10.5%	*10.5%*	*11.0%*	Return on Com Equity [E]	*12.0%*
7.0%	6.2%	7.0%	6.8%	6.5%	5.9%	5.3%	2.1%	3.5%	3.6%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
35%	42%	41%	47%	51%	57%	60%	71%	67%	66%	*67%*	*67%*	All Div'ds to Net Prof	*66%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $11033 mill. **Due in 5 Yrs** $3746.9 mill.
LT Debt $8746.6 mill. **LT Interest** $437.3 mill.
Incl. $27.0 mill. capitalized leases.
(LT interest earned: 4.8x)
Leases, Uncapitalized Annual rentals $9.5 mill.
Pension Assets-12/17 $2966.8 mill.
Oblig $3163.7 mill.
Pfd Stock $30.4 mill. **Pfd Div'd** $1.2 mill.
260,000 shs. 3.60%, $100 par, callable. $101;
44,498 shs. 6%, $100 par.
Common Stock 315,544,495 shs.
as of 1/31/18
MARKET CAP: $19 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	+29.1	+18.5	-3.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Lg. C&I Revs. per KWH (¢)	7.71	7.08	7.13
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+40.2	+.5	+.7
Fixed Charge Cov. (%)	364	404	422

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	2.5%	3.5%	*4.0%*
"Cash Flow"	5.5%	6.5%	*5.5%*
Earnings	7.5%	5.5%	*6.0%*
Dividends	15.5%	14.0%	*6.0%*
Book Value	8.5%	10.5%	*3.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	1387	991.2	1698	1848	5926.1
2016	2194	1602	1712	1963	7472.3
2017	2304	1631	1657	2055	7648.5
2018	*2350*	*1650*	*1650*	*2050*	*7700*
2019	*2450*	*1700*	*1700*	*2150*	*8000*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.86	.35	.58	.57	2.34
2016	1.09	.57	.68	.61	2.96
2017	1.12	.63	.68	.71	3.14
2018	*1.15*	*.70*	*.75*	*.70*	*3.30*
2019	*1.20*	*.73*	*.79*	*.73*	*3.45*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.39	.39	.39	.39	1.56
2015	.422	.422	.44	.457	1.74
2016	.495	.495	.495	.495	1.98
2017	.52	.52	.52	.52	2.08
2018	.553				

BUSINESS: WEC Energy Group, Inc. (formerly Wisconsin Energy) is a holding company for utilities that provide electric, gas & steam service in WI & gas service in IL, MN, & MI. Customers: 1.6 mill. elec., 2.8 mill. gas. Acq'd Integrys Energy 6/15. Sold Point Beach nuclear plant in '07. Elec. rev. breakdown: residential, 35%; small commercial & industrial, 31%; large commercial & industrial, 21%; other, 13%. Generating sources: coal, 49%; gas, 18%; renewables, 4%; purchased, 29%. Fuel costs: 37% of revs. '17 reported deprec. rates (utility): 2.3%-3.3%. Has 8,100 employees. Chairman & Interim CEO: Gale E. Klappa. President & CEO: Allen L. Leverett. Inc.: WI. Address: 231 W. Michigan St., P.O. Box 1331, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wecenergygroup.com.

Several factors should enable WEC Energy Group's earnings to rise in 2018 and 2019. Every year, the company's utilities receive rate relief through various regulatory mechanisms. Most notably, Peoples Gas in Chicago gets current recovery of its expenditures for an accelerated gas main-replacement program. This spending is expected to amount to $280 million-$300 million annually through 2023. Cost-reduction efforts should boost profits. Our 2018 earnings estimate is at the top end of WEC Energy's guidance of $3.26-$3.30 a share. Management's target for annual earnings growth is 5%-7%. Also . . .

WEC Energy's gas utility in Minnesota was granted an interim rate hike that took effect at the start of 2018. The increase was $9.5 million (3.8%), subject to refund. The company filed for a raise of $12.6 million (5.0%), based on a 10.3% return on equity. A final order is expected by yearend.

Construction of a gas-fired generating plant is under way in Michigan. The 180-megawatt facility is expected to be completed next year at a cost of $277 million. The company will recover half of its investment in the plant in rates and the other half through a 20-year contract with a large industrial customer.

The board of directors raised the dividend in the first quarter of 2018. The increase was $0.13 a share (6.25%) annually. WEC Energy's targets for the dividend are a payout ratio of 65%-70% and yearly growth of 5%-7% (matching its goal for earnings).

The new tax law benefited income in the fourth quarter of 2017. WEC Energy booked a noncash, nonrecurring gain of $0.65 a share.

The dividend yield of this timely stock is about average, by utility standards. Still, this might be sufficient for risk-averse investors, considering that the equity is ranked 1 (Highest) for Safety. However, even after the pullback in utility stocks in early 2018, the recent quotation is at the low end of our 2021-2023 Target Price Range. Accordingly, despite good dividend growth prospects, total return potential is unspectacular, albeit average for a utility.

Paul E. Debbas, CFA *March 16, 2018*

(A) Diluted EPS. Excl. gains on disc. ops.: '04, 77¢; '11, 6¢; nonrecurring gain: '17, 65¢. '15-'16 EPS don't sum due to rounding or chng. in shs. Next egs. report due early May. **(B)** Div'ds paid in early Mar., June, Sept. & Dec. ■ Div'd reinv. avail. **(C)** Incl. intang. In '17: $18.56/sh. **(D)** In mill., adj. for split. **(E)** Rate base: Net orig. cost. Rates all'd on com. eq. in WI in '15: 10.0%-10.3%; in IL in '15: 9.05%; in MN in '16: 9.11%; in MI in '16: 9.9%; earn. on avg. com. eq., '17: 13.0%. Reg. Climate: WI, Above Avg.; IL, Below Avg.; MN & MI, Avg.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	85

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WESTAR ENERGY NYSE-WR

RECENT PRICE **49.72** | P/E RATIO **20.1** (Trailing: 21.9 / Median: 16.0) | RELATIVE P/E RATIO **1.05** | DIV'D YLD **3.2%** | **VALUE LINE**

TIMELINESS — Suspended 6/10/16
SAFETY 2 Raised 4/1/05
TECHNICAL — Suspended 6/10/16
BETA .70 (1.00 = Market)

2021-23 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+20%)	8%
Low	45	(-10%)	1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	6	0	0	0	0	0	16
to Sell	0	0	0	4	0	0	5	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	130	164	141
to Sell	201	146	130
Hld's(000)	118673	118474	107206

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
High:	28.6	25.9	22.3	25.9	29.0	33.0	35.0	43.2	44.0	57.5	57.3	53.3								
Low:	22.8	16.0	14.9	20.6	22.6	26.8	28.6	31.7	33.9	40.0	49.2	47.1								
	24.77	20.06	17.02	18.23	18.37	18.09	16.98	17.04	18.34	17.27	17.88	18.48	19.76	17.40	18.07	18.09	*18.60*	*18.95*	Revenues per sh	*20.70*
	4.77	3.77	3.12	3.28	3.94	3.77	3.14	3.59	4.24	3.97	4.30	4.41	4.55	4.26	4.83	4.90	*5.30*	*5.65*	"Cash Flow" per sh	*6.75*
	1.00	1.48	1.17	1.55	1.88	1.84	1.31	1.28	1.80	1.79	2.15	2.27	2.35	2.09	2.43	2.27	*2.60*	*2.80*	Earnings per sh A	*3.45*
	1.20	.87	.80	.92	.98	1.08	1.16	1.20	1.24	1.28	1.32	1.36	1.40	1.44	1.52	1.60	*1.60*	*1.68*	Div'd Decl'd per sh B■†	*1.92*
	1.89	2.06	2.19	2.45	3.95	7.84	8.65	5.26	4.82	5.55	6.40	6.08	6.47	4.95	7.67	5.38	*6.50*	*6.75*	Cap'l Spending per sh	*7.50*
	13.68	14.23	16.13	16.31	17.62	19.14	20.18	20.59	21.25	22.03	22.89	23.88	25.02	25.87	26.84	27.50	*28.35*	*29.10*	Book Value per sh C	*31.60*
	71.51	72.84	86.03	86.84	87.39	95.46	108.31	109.07	112.13	125.70	126.50	128.25	131.69	141.35	141.79	142.09	*142.50*	*143.00*	Common Shs Outst'g E	*145.00*
	14.0	10.8	17.4	14.8	12.2	14.1	17.0	14.9	13.0	14.8	13.4	14.0	15.4	18.5	21.6	23.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.0*
	.76	.62	.92	.79	.66	.75	1.02	.99	.83	.93	.85	.79	.81	.93	1.13	1.15			Relative P/E Ratio	*.85*
	8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	5.2%	6.3%	5.3%	4.8%	4.6%	4.3%	3.9%	3.7%	2.9%	3.0%			Avg Ann'l Div'd Yield	*3.7%*
							1839.0	1858.2	2056.2	2171.0	2261.5	2370.7	2601.7	2459.2	2562.1	2571.0	*2650*	*2710*	Revenues ($mill)	*3000*
							136.8	141.3	203.9	214.0	275.1	292.5	313.3	291.9	346.6	323.9	*370*	*400*	Net Profit ($mill)	*500*
							24.8%	29.4%	29.0%	35.2%	30.9%	33.1%	31.9%	33.5%	33.8%	31.0%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
							--	--	--	--	--	--	--	10.4%	10.4%	*10.0%*	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
							49.8%	53.4%	53.6%	49.5%	51.2%	50.0%	50.0%	47.5%	47.9%	51.0%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
							49.7%	46.1%	46.0%	50.1%	48.8%	50.0%	50.0%	52.5%	52.1%	49.0%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
							4400.1	4866.8	5180.9	5531.0	5938.2	6131.1	6596.2	6958.8	7305.8	7595.7	*7750*	*7850*	Total Capital ($mill)	*8225*
							5533.5	5771.7	6309.5	6745.4	7335.7	7848.5	8441.5	8793.1	9506.3	9553.8	*9700*	*9800*	Net Plant ($mill)	*10500*
							4.2%	4.4%	5.5%	5.3%	6.0%	6.1%	6.0%	5.3%	5.7%	4.3%	*5.0%*	*5.0%*	Return on Total Cap'l	*6.0%*
							6.2%	6.2%	8.5%	7.7%	9.5%	9.6%	9.5%	8.0%	9.1%	8.3%	*9.0%*	*9.5%*	Return on Shr. Equity	*11.0%*
							6.2%	6.3%	8.5%	7.7%	9.4%	9.6%	9.5%	8.0%	9.1%	8.3%	*9.0%*	*9.5%*	Return on Com Equity D	*11.0%*
							1.2%	.8%	3.1%	2.7%	4.0%	4.2%	4.3%	2.9%	3.7%	2.4%	*3.5%*	*4.0%*	Retained to Com Eq	*5.0%*
							80%	87%	63%	65%	57%	56%	55%	69%	63%	70%	*62%*	*60%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $3963.3 mill. **Due in 5 Yrs** $725 mill.
LT Debt $3687.6 mill. **LT Interest** $170.0 mill.
(LT interest earned: 3.8x)

Pension Assets 12/17 $719 mill. **Oblig.** $1.1 bill.

Pfd Stock None

Common Stock 142,094,275 shs.
MARKET CAP: $7.1 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-2.5	+3.5	-1.3
Avg. Indust. Use (MWH)	5654	5781	5689
Avg. Indust. Revs. per KWH (¢)	6.68	6.77	6.71
Capacity at Peak (Mw)	7187	7523	7834
Peak Load, Summer (Mw)	5167	5184	5242
Annual Load Factor (%)	56.1	56.4	56.8
% Change Customers (yr-end)	+.2	+.3	+.6
Fixed Charge Cov. (%)	330	335	305

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '14-'16 to '21-'23
Revenues	0.5%	1.0%	*2.5%*
"Cash Flow"	3.0%	3.0%	*6.5%*
Earnings	4.0%	7.0%	*7.5%*
Dividends	5.0%	3.0%	*4.0%*
Book Value	4.5%	4.0%	*3.0%*

QUARTERLY REVENUES ($ mill.)

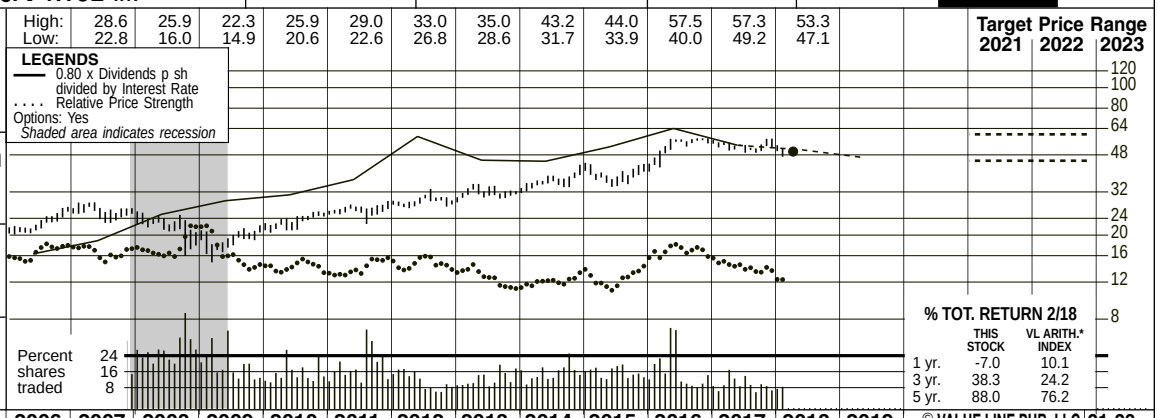
Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	590.8	589.6	732.8	546.0	2459.2
2016	569.5	621.4	764.7	606.5	2562.1
2017	572.6	609.3	794.3	594.8	2571.0
2018	*590*	*620*	*800*	*640*	*2650*
2019	*600*	*640*	*815*	*655*	*2710*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.38	.46	.97	.28	2.09
2016	.46	.51	1.08	.38	2.43
2017	.42	.50	1.11	.24	2.27
2018	*.50*	*.58*	*1.15*	*.37*	*2.60*
2019	*.54*	*.63*	*1.22*	*.41*	*2.80*

QUARTERLY DIVIDENDS PAID B■†

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.34	.35	.35	.35	1.39
2015	.35	.36	.36	.36	1.43
2016	.38	.38	.38	.38	1.52
2017	.40	.40	.40	.40	1.60
2018	.40				



% TOT. RETURN 2/18

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.0	10.1
3 yr.	38.3	24.2
5 yr.	88.0	76.2

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 708,000 customers mostly in Kansas. 2017 Electric revenue sources: residential and rural, 32%; commercial and business, 28%; industrial, 16%; other, 24%. The company sold its investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2017 depreciation rate: 2.5%. Estimated plant age: 17 years. Fuels: coal, 41%; nuclear, 7%; gas, 30%; renewable, 22%. Has 2,205 employees. Chief Executive Officer and President: Mark A. Ruelle. Chairman: Charles Q. Chandler. Incorporated: Kansas. Address: 818 South Kansas Avenue, Topeka, Kansas 66612. Telephone: 785-575-6300. Internet: www.westarenergy.com.

The proposed merger of equals between Westar Energy and Great Plains Energy is on track to close in the first half of 2018. Under the agreement, no premium would be paid and no cash would be exchanged with respect to either entity. A holding company would be created in which Westar stockholders receive one share for each of their current shares, and Great Plains stockholders receive 0.5981 shares for each share that they own. The tax-free transaction has been approved by each company's stockholders and is expected to be finalized in May or June. In addition, settlements have been reached in Missouri and Kansas. Approval from the state commissions are expected in the coming weeks.

We continue to advise investors to hold their shares. The companies are targeting average annual earnings and dividend growth of 6%-8%, with a targeted payout ratio of 60%-70%. The utilities also expect to save $550 million in the first five years upon completion of the deal, and $140 million to $170 million annually thereafter. If the transaction fails to win regulatory approval, Westar would receive a $190 million termination fee from GXP.

The combined entity expects to set its initial dividend at a level that maintains the current payout for Great Plains stockholders. This would result in an increase of about 15% for Westar stockholders.

The new tax legislation will not have a material impact on earnings. In February, Westar asked the Kansas Corporation Commission to update its prices and reduce rates by approximately $74 million, which is the amount it expects to save each year under the new tax law. The company's request also included $11 million of initial savings in contemplation of its proposed merger with Great Plains Energy, and $29 million in savings achieved from refinancing debt. A decision by the KCC on all matters is due in September.

This stock is unranked for Timeliness due to the pending transaction. Although state regulators blocked the initial merger between Westar and Great Plains, the revised accord has been altered to appeal to all parties involved. Thus, we expect the deal to proceed as planned.

Daniel Henigson *March 16, 2018*

(A) EPS diluted from 2010 onward. Excl. nonrecur. gains (losses): '02, ($12.06); '03, 77¢; '08, 39¢; '11, 14¢. Earnings may not sum due to rounding. Next earnings report due early May.
(B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. **(C)** Incl. reg. assets. In 2017: $5.66/sh. **(D)** Rate base determined: fair value; Rate allowed on common equity in '17: 10.0%; earned on avg. com. eq., '17: 9.5%. Regul. Clim.: Avg. **(E)** In mill.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	85

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XCEL ENERGY NDQ-XEL

RECENT PRICE **45.61** | P/E RATIO **18.8** (Trailing: 19.7 Median: 15.0) | RELATIVE P/E RATIO **1.00** | DIV'D YLD **3.4%** | **VALUE LINE**

TIMELINESS **4** Lowered 3/23/18
SAFETY **1** Raised 5/1/15
TECHNICAL **5** Lowered 4/27/18
BETA .60 (1.00 = Market)

2021-23 PROJECTIONS

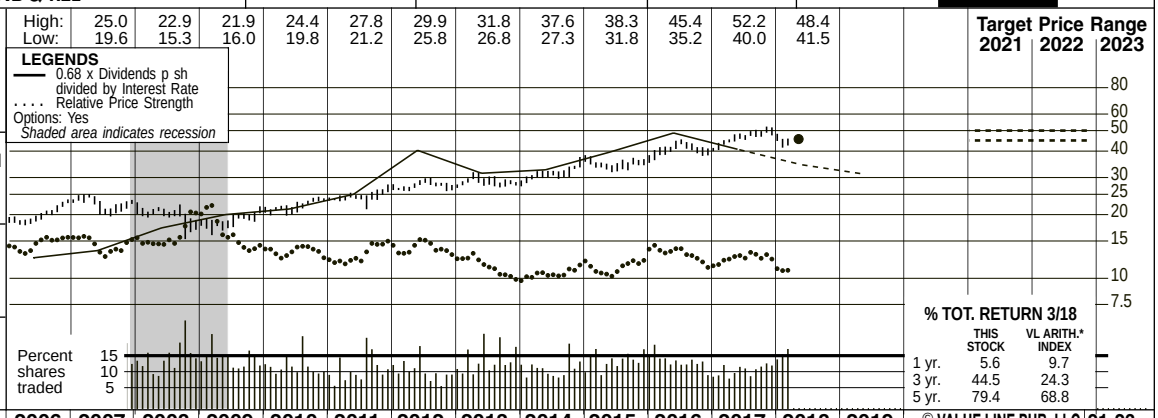
	Price	Gain	Ann'l Total Return
High	50	(+10%)	6%
Low	45	(Nil)	3%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	1	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	12
to Sell	0	0	1	0	0	1	1	0	0

Institutional Decisions

	2Q2017	3Q2017	4Q2017
to Buy	294	286	280
to Sell	242	246	216
Hld's(000)	416718	418292	379245



2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	© VALUE LINE PUB. LLC	21-23
23.89	19.90	20.84	23.86	24.16	23.40	24.69	21.08	21.38	21.90	20.76	21.92	23.11	21.72	21.90	22.46	*22.55*	*22.90*	Revenues per sh	*25.25*
3.14	3.35	3.27	3.28	3.61	3.45	3.50	3.48	3.51	3.79	4.00	4.10	4.28	4.56	5.04	5.47	*5.90*	*6.15*	"Cash Flow" per sh	*7.25*
.42	1.23	1.27	1.20	1.35	1.35	1.46	1.49	1.56	1.72	1.85	1.91	2.03	2.10	2.21	2.30	*2.45*	*2.55*	Earnings per sh A	*3.00*
1.13	.75	.81	.85	.88	.91	.94	.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	1.44	*1.52*	*1.60*	Div'd Decl'd per sh B ■	*1.90*
6.04	2.49	3.19	3.25	4.00	4.89	4.66	3.91	4.60	4.53	5.27	6.82	6.33	7.26	6.42	6.54	*8.25*	*7.95*	Cap'l Spending per sh	*6.75*
11.70	12.95	12.99	13.37	14.28	14.70	15.35	15.92	16.76	17.44	18.19	19.21	20.20	20.89	21.73	22.56	*23.55*	*24.85*	Book Value per sh C	*28.00*
398.71	398.96	400.46	403.39	407.30	428.78	453.79	457.51	482.33	486.49	487.96	497.97	505.73	507.54	507.22	507.76	*509.50*	*518.00*	Common Shs Outst'g D	*522.50*
NMF	11.6	13.6	15.4	14.8	16.7	13.7	12.7	14.1	14.2	14.8	15.0	15.4	16.5	18.5	20.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.0*
NMF	.66	.72	.82	.80	.89	.82	.85	.90	.89	.94	.84	.81	.83	.97	1.02			Relative P/E Ratio	*.90*
6.6%	5.2%	4.7%	4.6%	4.4%	4.0%	4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%	3.7%	3.3%	3.1%			Avg Ann'l Div'd Yield	*4.0%*
11203	9644.3	10311	10655	10128	10915	11686	11024	11107	11404	*11500*	*11850*	Revenues ($mill)	*13250*
645.7	685.5	727.0	841.4	905.2	948.2	1021.3	1063.6	1123.4	1171.0	*1240*	*1320*	Net Profit ($mill)	*1575*
34.4%	35.1%	37.5%	35.8%	33.2%	33.8%	33.9%	35.8%	34.1%	30.7%	*9.0%*	*9.0%*	Income Tax Rate	*9.0%*
15.9%	16.8%	11.7%	9.4%	10.8%	13.4%	12.5%	7.7%	7.8%	9.4%	*11.0%*	*10.0%*	AFUDC % to Net Profit	*7.0%*
52.2%	51.6%	53.1%	51.1%	53.3%	53.3%	53.0%	54.1%	56.3%	55.9%	*58.0%*	*57.0%*	Long-Term Debt Ratio	*58.0%*
47.1%	47.7%	46.3%	48.9%	46.7%	46.7%	47.0%	45.9%	43.7%	44.1%	*42.0%*	*43.0%*	Common Equity Ratio	*42.0%*
14800	15277	17452	17331	19018	20477	21714	23092	25216	25975	*28450*	*29775*	Total Capital ($mill)	*34800*
17689	18508	20663	22353	23809	26122	28757	31206	32842	34329	*36775*	*39050*	Net Plant ($mill)	*42900*
6.0%	6.2%	5.7%	6.5%	6.1%	6.0%	6.0%	5.8%	5.7%	5.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
9.1%	9.3%	8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	*10.5%*	*10.5%*	Return on Shr. Equity	*10.5%*
9.2%	9.4%	8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	*10.5%*	*10.5%*	Return on Com Equity E	*10.5%*
3.8%	3.7%	3.6%	4.3%	4.7%	4.5%	4.5%	4.3%	4.0%	3.9%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
59%	61%	59%	56%	54%	54%	55%	57%	61%	62%	*62%*	*62%*	All Div'ds to Net Prof	*63%*

CAPITAL STRUCTURE as of 12/31/17
Total Debt $15791 mill. **Due in 5 Yrs** $4262 mill.
LT Debt $14520 mill. **LT Interest** $646 mill.
Incl. $151 mill. capitalized leases.
(LT interest earned: 3.5x)

Leases, Uncapitalized Annual rentals $238 mill.
Pension Assets-12/17 $3088 mill.
Oblig $3828 mill.

Pfd Stock None

Common Stock 508,064,983 shs.
as of 2/19/18
MARKET CAP: $23 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2015	2016	2017
% Change Retail Sales (KWH)	-.6	+.3	-.7
Large C & I Use (MWH)	23521	22519	22642
Large C & I Revs. per KWH (¢)	6.10	6.17	6.36
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	19583	20423	19591
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.9	+.9	+.9
Fixed Charge Cov. (%)	358	342	330

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '15-'17 to '21-'23
Revenues	-1.0%	.5%	*2.5%*
"Cash Flow"	4.0%	6.0%	*6.5%*
Earnings	5.5%	5.0%	*5.5%*
Dividends	4.5%	5.5%	*5.5%*
Book Value	4.5%	4.5%	*4.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	2962	2515	2901	2646	11024
2016	2772	2500	3040	2795	11107
2017	2946	2645	3017	2796	11404
2018	*2900*	*2650*	*3050*	*2900*	*11500*
2019	*3000*	*2700*	*3150*	*3000*	*11850*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.46	.39	.84	.41	2.10
2016	.47	.39	.90	.45	2.21
2017	.47	.45	.97	.42	2.30
2018	*.55*	*.45*	*1.00*	*.45*	*2.45*
2019	*.58*	*.47*	*1.03*	*.47*	*2.55*

QUARTERLY DIVIDENDS PAID B ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	.28	.30	.30	.30	1.18
2015	.30	.32	.32	.32	1.26
2016	.32	.34	.34	.34	1.34
2017	.34	.36	.36	.36	1.42
2018	.36	.38			

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies electricity to Minnesota, Wisconsin, North Dakota, South Dakota & Michigan & gas to Minnesota, Wisconsin, North Dakota & Michigan; Public Service of Colorado, which supplies electricity & gas to Colorado; & Southwestern Public Service, which supplies electricity to Texas & New Mexico. Customers: 3.6 mill. electric, 1.9 mill. gas. Elec. rev. breakdown: residential, 31%; sm. comm'l & ind'l, 36%; lg. comm'l & ind'l, 18%; other, 15%. Generating sources not available. Fuel costs: 40% of revs. '17 reported depr. rate: 3.1%. Has 11,500 employees. Chairman, Pres. & CEO: Ben Fowke. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

Xcel Energy is awaiting orders on rate cases in three states. The largest ones are Public Service of Colorado's multiyear electric and gas applications. The utility requested electric hikes totaling $245 million from 2018 through 2020, and gas increases totaling $139 million over that span. Each filing is based on a 10% return on a 55.25% common-equity ratio. An interim gas increase of $63 million took effect at the start of 2018, and the company is asking for a $75 million interim gas raise at the start of June. Southwestern Public Service asked the regulators in Texas and New Mexico for a total of $97 million, based on a 10.25% return on a 58% common-equity ratio. Rulings are expected this summer in New Mexico and early in the fourth quarter (retroactive to January of 2018) in Texas.

Rate relief is boosting Xcel's earning power and enabling the company to reduce the gap between its earned and allowed returns on equity. Management's earnings guidance for 2018 is $2.37-$2.47 a share. Our estimate of $2.45 is near the upper end of this range. We forecast more-modest profit growth in 2019. Xcel's goal for long-term earnings growth is 5%-6% annually.

Xcel's utilities have some proposals pending involving renewable energy. The aim is to retire coal-fired units and replace them with renewables, gas, and storage — and to do this without raising rates for customers. SPS received approval in New Mexico, and awaits a decision in Texas, for a $1.6 billion project to add wind in the two states. P.S. of Colorado expects a ruling in July on its plan to spend up to $1.5 billion to add wind, solar, and gas.

The board of directors raised the common dividend, effective with the April payment. The increase was $0.02 a share (5.6%) quarterly, the same as in recent years. Xcel's goals for the dividend are growth of 5%-7% annually and a payout ratio of 60%-70%.

This untimely stock has a dividend yield and 3- to 5-year total return potential that are about average, by utility standards. This might be acceptable for conservative accounts, given the issue's top rank for Safety.

Paul E. Debbas, CFA *April 27, 2018*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '02, ($6.27); '10, 5¢; '15, (16¢); '17, (5¢); gains (losses) on discontinued ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢; '09, (1¢); '10, 1¢. '17 EPS don't sum due to rounding. Next earnings report due early May. **(B)** Div'ds historically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. **(C)** Incl. intangibles. In '17: $5.92/sh. **(D)** In mill. **(E)** Rate base: Varies. Rate allowed on com. eq. (blended): 9.6%; earned on avg. com. eq., '17: 10.4%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	100

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ALLETE, Inc. (ALE)

NYSE - Nasdaq Real Time Price. Currency in USD

Add to watchlist

Quote Lookup

74.21 +0.21 (+0.28%)

As of 10:05AM EDT. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	5	4	6	6
Avg. Estimate	0.98	0.72	3.41	3.68
Low Estimate	0.92	0.67	3.28	3.44
High Estimate	1.02	0.76	3.5	3.79
Year Ago EPS	0.97	0.72	3.19	3.41

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	2	2	4	4
Avg. Estimate	377M	365M	1.48B	1.54B
Low Estimate	355M	342M	1.41B	1.43B
High Estimate	399M	388M	1.58B	1.7B
Year Ago Sales	365.6M	353.3M	1.42B	1.48B
Sales Growth (year/est)	3.10%	3.30%	4.40%	3.60%

Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	0.94	0.55	0.94	0.73
EPS Actual	0.97	0.72	0.72	0.78
Difference	0.03	0.17	-0.22	0.05
Surprise %	3.20%	30.90%	-23.40%	6.80%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.98	0.72	3.41	3.68
7 Days Ago	0.98	0.72	3.41	3.68
30 Days Ago	0.98	0.72	3.4	3.67
60 Days Ago	0.98	0.73	3.4	3.64
90 Days Ago	1.03	0.79	3.62	3.86

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	1	1	1	1
Down Last 7 Days	N/A	N/A	N/A	N/A

Yahoo Small Business

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EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	ALE	Industry	Sector	S&P 500
Current Qtr.	1.00%	N/A	N/A	0.43
Next Qtr.	N/A	N/A	N/A	0.41
Current Year	6.90%	N/A	N/A	0.21
Next Year	7.90%	N/A	N/A	0.10
Next 5 Years (per annum)	6.00%	N/A	N/A	0.12
Past 5 Years (per annum)	3.82%	N/A	N/A	N/A

Black Hills Corporation (BKH)

Add to watchlist

NYSE - Nasdaq Real Time Price. Currency in USD

Quote Lookup

56.22 +0.02 (+0.04%)

As of 10:04AM EDT. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	7	6	8	7
Avg. Estimate	1.53	0.41	3.43	3.46
Low Estimate	1.44	0.34	3.3	3.41
High Estimate	1.69	0.45	3.7	3.55
Year Ago EPS	1.41	0.41	3.36	3.43

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	4	4	7	6
Avg. Estimate	557.86M	368.91M	1.77B	1.83B
Low Estimate	544.44M	341.67M	1.65B	1.7B
High Estimate	581.7M	409.58M	1.87B	1.96B
Year Ago Sales	554M	348M	1.68B	1.77B
Sales Growth (year/est)	0.70%	6.00%	5.50%	3.40%

Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	1.4	0.5	0.55	1.05
EPS Actual	1.41	0.41	0.5	0.98
Difference	0.01	-0.09	-0.05	-0.07
Surprise %	0.70%	-18.00%	-9.10%	-6.70%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	1.53	0.41	3.43	3.46
7 Days Ago	1.54	0.41	3.43	3.46
30 Days Ago	1.53	0.41	3.43	3.47
60 Days Ago	1.5	0.42	3.39	3.48
90 Days Ago	1.33	0.34	3.42	3.52

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	2	1	2	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A

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EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Down Last 30 Days	1	N/A	N/A	N/A

Growth Estimates	BKH	Industry	Sector	S&P 500
Current Qtr.	8.50%	N/A	N/A	0.43
Next Qtr.	N/A	N/A	N/A	0.41
Current Year	2.10%	N/A	N/A	0.21
Next Year	0.90%	N/A	N/A	0.10
Next 5 Years (per annum)	4.07%	N/A	N/A	0.12
Past 5 Years (per annum)	3.19%	N/A	N/A	N/A

El Paso Electric Company (EE)

Add to watchlist

NYSE - Nasdaq Real Time Price. Currency in USD

Quote Lookup

54.80 +0.40 (+0.74%)

As of 10:04AM EDT. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	2	2	4	3
Avg. Estimate	-0.07	0.88	2.55	2.74
Low Estimate	-0.1	0.79	2.47	2.65
High Estimate	-0.03	0.96	2.66	2.83
Year Ago EPS	-0.1	0.89	2.42	2.55

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	1	1	2	1
Avg. Estimate	168.5M	248.73M	891.17M	896M
Low Estimate	168.5M	248.73M	878M	896M
High Estimate	168.5M	248.73M	904.33M	896M
Year Ago Sales	171.34M	251.84M	916.8M	891.17M
Sales Growth (year/est)	-1.70%	-1.20%	-2.80%	0.50%

Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	-0.08	0.74	1.58	0.21
EPS Actual	-0.1	0.89	1.47	0.16
Difference	-0.02	0.15	-0.11	-0.05
Surprise %	-25.00%	20.30%	-7.00%	-23.80%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	-0.07	0.88	2.55	2.74
7 Days Ago	-0.07	0.88	2.54	2.72
30 Days Ago	-0.03	0.92	2.57	2.71
60 Days Ago	-0.02	0.92	2.63	2.84
90 Days Ago	-0.02	0.92	2.65	2.84

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	N/A	N/A	N/A	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A

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EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Down Last 30 Days	1	1	N/A	N/A

Growth Estimates	EE	Industry	Sector	S&P 500
Current Qtr.	30.00%	N/A	N/A	0.43
Next Qtr.	-1.10%	N/A	N/A	0.41
Current Year	5.40%	N/A	N/A	0.21
Next Year	7.50%	N/A	N/A	0.10
Next 5 Years (per annum)	5.20%	N/A	N/A	0.12
Past 5 Years (per annum)	18.89%	N/A	N/A	N/A

Hawaiian Electric Industries, Inc. (HE)

Add to watchlist

NYSE - Nasdaq Real Time Price. Currency in USD

Quote Lookup

33.0500 -0.0900 (-0.27%)

As of 10:04AM EDT. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	4	4	5	5
Avg. Estimate	0.38	0.44	1.91	2.05
Low Estimate	0.36	0.39	1.86	1.97
High Estimate	0.4	0.52	1.97	2.15
Year Ago EPS	0.31	0.36	1.65	1.91

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	3	3	5	5
Avg. Estimate	576.59M	607.86M	2.56B	2.61B
Low Estimate	512.94M	527.05M	2.44B	2.44B
High Estimate	620.82M	661.54M	2.67B	2.74B
Year Ago Sales	591.56M	632.28M	2.56B	2.56B
Sales Growth (year/est)	-2.50%	-3.90%	0.20%	1.90%

Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	0.28	0.39	0.57	0.41
EPS Actual	0.31	0.36	0.55	0.43
Difference	0.03	-0.03	-0.02	0.02
Surprise %	10.70%	-7.70%	-3.50%	4.90%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.38	0.44	1.91	2.05
7 Days Ago	0.38	0.44	1.89	2.02
30 Days Ago	0.38	0.42	1.88	2.01
60 Days Ago	0.38	0.43	1.88	2
90 Days Ago	0.39	0.43	1.84	1.91

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	N/A	N/A	N/A	N/A
Up Last 30 Days	1	1	2	1
Down Last 7 Days	N/A	N/A	N/A	N/A

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EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	HE	Industry	Sector	S&P 500
Current Qtr.	22.60%	N/A	N/A	0.43
Next Qtr.	22.20%	N/A	N/A	0.41
Current Year	15.80%	N/A	N/A	0.21
Next Year	7.30%	N/A	N/A	0.10
Next 5 Years (per annum)	8.60%	N/A	N/A	0.12
Past 5 Years (per annum)	1.24%	N/A	N/A	N/A

IDACORP, Inc. (IDA)

Add to watchlist

NYSE - Nasdaq Real Time Price. Currency in USD

Quote Lookup

88.125 +0.085 (+0.10%)

As of 10:03AM EDT. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	4	3	4	3
Avg. Estimate	0.7	1.01	4.21	4.37
Low Estimate	0.68	0.95	4.18	4.32
High Estimate	0.73	1.06	4.27	4.45
Year Ago EPS	0.66	0.99	4.21	4.21

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	1	1	3	1
Avg. Estimate	302.93M	328.74M	1.32B	1.34B
Low Estimate	302.93M	328.74M	1.32B	1.34B
High Estimate	302.93M	328.74M	1.34B	1.34B
Year Ago Sales	N/A	333.01M	1.35B	1.32B
Sales Growth (year/est)	N/A	-1.30%	-1.80%	1.10%

Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	0.54	1.07	1.66	0.67
EPS Actual	0.66	0.99	1.8	0.77
Difference	0.12	-0.08	0.14	0.1
Surprise %	22.20%	-7.50%	8.40%	14.90%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.7	1.01	4.21	4.37
7 Days Ago	0.69	1.02	4.21	4.37
30 Days Ago	0.67	1.02	4.2	4.37
60 Days Ago	0.68	1.06	4.2	4.39
90 Days Ago	0.68	1.08	4.16	4.31

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	1	N/A	N/A	N/A
Up Last 30 Days	2	N/A	1	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A

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EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Down Last 30 Days	N/A	1	N/A	N/A

Growth Estimates	IDA	Industry	Sector	S&P 500
Current Qtr.	6.10%	N/A	N/A	0.43
Next Qtr.	2.00%	N/A	N/A	0.41
Current Year	N/A	N/A	N/A	0.21
Next Year	3.80%	N/A	N/A	0.10
Next 5 Years (per annum)	3.10%	N/A	N/A	0.12
Past 5 Years (per annum)	9.47%	N/A	N/A	N/A

Alliant Energy Corporation (LNT)

Add to watchlist

NYSE - Nasdaq Real Time Price. Currency in USD

Quote Lookup

40.71 +0.07 (+0.17%)

As of 10:04AM EDT. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Jun 2018)	Next Qtr. (Sep 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	5	5	7	7
Avg. Estimate	0.43	0.82	2.12	2.25
Low Estimate	0.4	0.77	2.1	2.22
High Estimate	0.45	0.87	2.17	2.27
Year Ago EPS	0.41	0.75	1.93	2.12

Revenue Estimate	Current Qtr. (Jun 2018)	Next Qtr. (Sep 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	2	2	5	6
Avg. Estimate	786.16M	1.08B	3.5B	3.64B
Low Estimate	777.25M	921.95M	3.44B	3.53B
High Estimate	795.08M	1.23B	3.61B	3.77B
Year Ago Sales	765.3M	906.9M	3.38B	3.5B
Sales Growth (year/est)	2.70%	18.60%	3.60%	4.00%

Earnings History	6/29/2017	9/29/2017	12/30/2017	3/30/2018
EPS Est.	0.38	0.86	0.36	0.5
EPS Actual	0.41	0.75	0.33	0.52
Difference	0.03	-0.11	-0.03	0.02
Surprise %	7.90%	-12.80%	-8.30%	4.00%

EPS Trend	Current Qtr. (Jun 2018)	Next Qtr. (Sep 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.43	0.82	2.12	2.25
7 Days Ago	0.43	0.82	2.11	2.25
30 Days Ago	0.42	0.88	2.11	2.24
60 Days Ago	0.42	0.88	2.11	2.24
90 Days Ago	0.4	0.95	2.11	2.24

EPS Revisions	Current Qtr. (Jun 2018)	Next Qtr. (Sep 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	N/A	N/A	1	N/A
Up Last 30 Days	2	1	2	1
Down Last 7 Days	N/A	N/A	N/A	N/A

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EPS Revisions	Current Qtr. (Jun 2018)	Next Qtr. (Sep 2018)	Current Year (2018)	Next Year (2019)
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	LNT	Industry	Sector	S&P 500
Current Qtr.	4.90%	N/A	N/A	0.43
Next Qtr.	9.30%	N/A	N/A	0.41
Current Year	9.80%	N/A	N/A	0.21
Next Year	6.10%	N/A	N/A	0.10
Next 5 Years (per annum)	5.85%	N/A	N/A	0.12
Past 5 Years (per annum)	4.13%	N/A	N/A	N/A

NorthWestern Corporation (NWE)

Add to watchlist

NYSE - Nasdaq Real Time Price. Currency in USD

Quote Lookup

53.21 -0.05 (-0.09%)

As of 10:04AM EDT. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	5	4	5	5
Avg. Estimate	1.17	0.45	3.42	3.4
Low Estimate	1.14	0.34	3.39	3.24
High Estimate	1.2	0.51	3.45	3.5
Year Ago EPS	1.13	0.47	3.3	3.42

Revenue Estimate	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	2	2	4	3
Avg. Estimate	366.58M	285.54M	1.31B	1.34B
Low Estimate	363.56M	284.93M	1.31B	1.33B
High Estimate	369.59M	286.14M	1.32B	1.34B
Year Ago Sales	367.31M	283.86M	1.31B	1.31B
Sales Growth (year/est)	-0.20%	0.60%	0.50%	1.80%

Earnings History	3/30/2017	6/29/2017	9/29/2017	12/30/2017
EPS Est.	1.03	0.63	0.71	1.03
EPS Actual	1.13	0.47	0.74	0.96
Difference	0.1	-0.16	0.03	-0.07
Surprise %	9.70%	-25.40%	4.20%	-6.80%

EPS Trend	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	1.17	0.45	3.42	3.4
7 Days Ago	1.14	0.44	3.42	3.4
30 Days Ago	1.14	0.44	3.42	3.4
60 Days Ago	1.12	0.44	3.41	3.39
90 Days Ago	1.18	0.48	3.42	3.39

EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	1	N/A	1	1
Up Last 30 Days	2	N/A	1	1
Down Last 7 Days	N/A	N/A	N/A	N/A

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EPS Revisions	Current Qtr. (Mar 2018)	Next Qtr. (Jun 2018)	Current Year (2018)	Next Year (2019)
Down Last 30 Days	N/A	N/A	N/A	N/A

Growth Estimates	NWE	Industry	Sector	S&P 500
Current Qtr.	3.50%	N/A	N/A	0.43
Next Qtr.	-4.30%	N/A	N/A	0.41
Current Year	3.60%	N/A	N/A	0.21
Next Year	-0.60%	N/A	N/A	0.10
Next 5 Years (per annum)	3.16%	N/A	N/A	0.12
Past 5 Years (per annum)	8.34%	N/A	N/A	N/A

OGE Energy Corp. (OGE)

Add to watchlist

NYSE - Nasdaq Real Time Price. Currency in USD

33.55 +0.24 (+0.72%)

As of 10:06AM EDT. Market open.

Quote Lookup

Currency in USD

Earnings Estimate	Current Qtr. (Jun 2018)	Next Qtr. (Sep 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	5	5	9	9
Avg. Estimate	0.51	0.9	2.01	2.11
Low Estimate	0.34	0.6	1.95	2.05
High Estimate	0.6	1.09	2.06	2.16
Year Ago EPS	0.52	0.92	1.92	2.01

Revenue Estimate	Current Qtr. (Jun 2018)	Next Qtr. (Sep 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	2	2	5	6
Avg. Estimate	599.82M	731.83M	2.31B	2.44B
Low Estimate	594.17M	724.57M	2.28B	2.35B
High Estimate	605.46M	739.09M	2.35B	2.64B
Year Ago Sales	586.4M	716.8M	2.26B	2.31B
Sales Growth (year/est)	2.30%	2.10%	2.10%	5.70%

Earnings History	6/29/2017	9/29/2017	12/30/2017	3/30/2018
EPS Est.	0.47	0.94	0.28	0.15
EPS Actual	0.52	0.92	0.3	0.27
Difference	0.05	-0.02	0.02	0.12
Surprise %	10.60%	-2.10%	7.10%	80.00%

EPS Trend	Current Qtr. (Jun 2018)	Next Qtr. (Sep 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	0.51	0.9	2.01	2.11
7 Days Ago	0.5	0.9	2	2.1
30 Days Ago	0.44	0.84	2.01	2.11
60 Days Ago	0.4	0.78	2	2.11
90 Days Ago	0.52	0.98	2.04	2.15

EPS Revisions	Current Qtr. (Jun 2018)	Next Qtr. (Sep 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	1	1	1	N/A
Up Last 30 Days	1	1	1	N/A
Down Last 7 Days	N/A	N/A	N/A	N/A

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EPS Revisions	Current Qtr. (Jun 2018)	Next Qtr. (Sep 2018)	Current Year (2018)	Next Year (2019)
Down Last 30 Days	1	1	N/A	1

Growth Estimates	OGE	Industry	Sector	S&P 500
Current Qtr.	-1.90%	N/A	N/A	0.43
Next Qtr.	-2.20%	N/A	N/A	0.41
Current Year	4.70%	N/A	N/A	0.21
Next Year	5.00%	N/A	N/A	0.10
Next 5 Years (per annum)	4.30%	N/A	N/A	0.12
Past 5 Years (per annum)	5.45%	N/A	N/A	N/A

Pinnacle West Capital Corporation (PNW)

Add to watchlist

NYSE - Nasdaq Real Time Price. Currency in USD

Quote Lookup

76.62 +0.25 (+0.33%)

As of 10:05AM EDT. Market open.

Currency in USD

Earnings Estimate	Current Qtr. (Jun 2018)	Next Qtr. (Sep 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	9	9	15	15
Avg. Estimate	1.5	2.68	4.47	4.71
Low Estimate	1.33	2.47	4.4	4.67
High Estimate	1.61	2.84	4.55	4.76
Year Ago EPS	1.49	2.46	4.35	4.47

Revenue Estimate	Current Qtr. (Jun 2018)	Next Qtr. (Sep 2018)	Current Year (2018)	Next Year (2019)
No. of Analysts	4	4	10	10
Avg. Estimate	955.09M	1.2B	3.64B	3.75B
Low Estimate	933.65M	1.18B	3.48B	3.59B
High Estimate	968.37M	1.21B	3.97B	4.16B
Year Ago Sales	944.59M	1.18B	3.57B	3.64B
Sales Growth (year/est)	1.10%	1.10%	2.10%	3.10%

Earnings History	6/29/2017	9/29/2017	12/30/2017	3/30/2018
EPS Est.	1.17	2.32	0.12	0.07
EPS Actual	1.49	2.46	0.19	0.03
Difference	0.32	0.14	0.07	-0.04
Surprise %	27.40%	6.00%	58.30%	-57.10%

EPS Trend	Current Qtr. (Jun 2018)	Next Qtr. (Sep 2018)	Current Year (2018)	Next Year (2019)
Current Estimate	1.5	2.68	4.47	4.71
7 Days Ago	1.49	2.67	4.47	4.7
30 Days Ago	1.47	2.61	4.47	4.7
60 Days Ago	1.47	2.6	4.46	4.7
90 Days Ago	1.49	2.55	4.41	4.7

EPS Revisions	Current Qtr. (Jun 2018)	Next Qtr. (Sep 2018)	Current Year (2018)	Next Year (2019)
Up Last 7 Days	2	2	N/A	1
Up Last 30 Days	2	4	N/A	2
Down Last 7 Days	N/A	N/A	N/A	N/A

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EPS Revisions	Current Qtr. (Jun 2018)	Next Qtr. (Sep 2018)	Current Year (2018)	Next Year (2019)
Down Last 30 Days	1	N/A	N/A	N/A

Growth Estimates	PNW	Industry	Sector	S&P 500
Current Qtr.	0.70%	N/A	N/A	0.43
Next Qtr.	8.90%	N/A	N/A	0.41
Current Year	2.80%	N/A	N/A	0.21
Next Year	5.40%	N/A	N/A	0.10
Next 5 Years (per annum)	3.78%	N/A	N/A	0.12
Past 5 Years (per annum)	10.03%	N/A	N/A	N/A

Allete, Inc. (ALE)

(Real Time Quote from BATS)

$74.15 USD

+0.15 (0.20%)

Updated May 18, 2018 09:54 AM ET

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D Value | C Growth | C Momentum | D VGM

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Top 40%(106 out of 265)
Industry: Utility - Electric Power

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Trades from $1

Detailed Estimates

Enter Symbol

Estimates	
Next Report Date	8/1/18
Current Quarter	0.75
EPS Last Quarter	0.99
Last EPS Surprise	0.00%
ABR	3.00
Earnings ESP	2.01%
Current Year	3.36
Next Year	3.57
EPS (TTM)	3.37
P/E (F1)	22.02

Growth Estimates	ALE	IND	S&P
Current Qtr (06/2018)	4.17	-15.71	28.38
Next Qtr (09/2018)	-25.96	11.59	24.55
Current Year (12/2018)	5.33	6.80	NA
Next Year (12/2019)	6.25	6.60	7.10
Past 5 Years	3.90	6.50	NA
Next 5 Years	6.60	6.90	NA
PE	22.02	23.50	17.55
PEG Ratio	3.34	3.41	NA

Learn More About Estimate Research

See Brokerage Recommendations

See Earnings Report Transcript

Premium Research for ALE

Zacks Rank	**Buy 2**
Zacks Industry Rank	Top 40%(106 out of 265)
Zacks Sector Rank	Bottom 13% (14 out of 16)
Style Scores	**D Value | C Growth | C Momentum | D VGM**
Earnings ESP	2.01%
Research Report for ALE	Snapshot

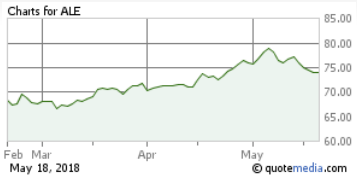
(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research »

Research for ALE

Chart for ALE



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Predict to see real-time community sentiment

	Monday	In a Week	In a Month	In 3 Months
ALE Allete, Inc.				

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Sales Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	342.22M	340.08M	1.41B	1.43B
# of Estimates	1	1	1	1
High Estimate	342.22M	340.08M	1.41B	1.43B
Low Estimate	342.22M	340.08M	1.41B	1.43B
Year ago Sales	353.30M	362.50M	1.42B	1.41B

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Year over Year Growth Est.	-3.14%	-6.18%	-0.59%	1.34%

Earnings Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.75	0.77	3.36	3.57
# of Estimates	2	2	3	3
Most Recent Consensus	NA	NA	NA	3.60
High Estimate	0.76	0.78	3.40	3.68
Low Estimate	0.73	0.75	3.28	3.44
Year ago EPS	0.72	1.04	3.19	3.36
Year over Year Growth Est.	4.17%	-25.96%	5.33%	6.35%

Agreement - Estimate Revisions

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Up Last 60 Days	1	1	1	1
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	0	0	0
Down Last 60 Days	0	0	0	0

Magnitude - Consensus Estimate Trend

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.75	0.77	3.36	3.57
7 Days Ago	0.75	0.77	3.36	3.57
30 Days Ago	0.75	0.77	3.36	3.57
60 Days Ago	0.74	0.76	3.34	3.55
90 Days Ago	0.73	0.74	3.36	3.43

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	0.76	0.75	3.40	3.64
Zacks Consensus Estimate	0.75	0.77	3.36	3.57
Earnings ESP	2.01%	-1.96%	1.19%	1.87%

Surprise - Reported Earnings History

	Quarter Ending (3/2018)	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Average Surprise
Reported	0.99	0.62	1.04	0.72	NA
Estimate	0.99	0.75	0.95	0.57	NA
Difference	0.00	-0.13	0.09	0.15	0.03
Surprise	0.00%	-17.33%	9.47%	26.32%	4.62%

Quarterly Estimates By Analyst

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Annual Estimates By Analyst

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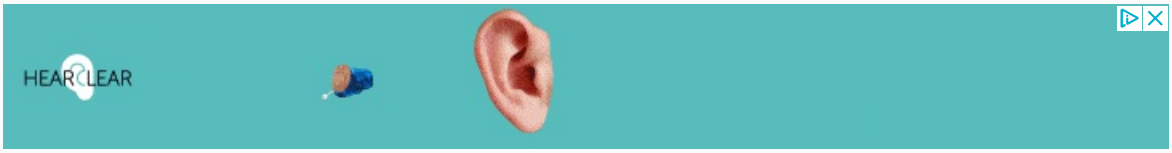

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Black Hills Corporation (BKH)

(Real Time Quote from BATS)

$56.17 USD

-0.03 (-0.05%)

Updated May 18, 2018 09:54 AM ET

Add to portfolio

Zacks Rank:

3-Hold

Style Scores:

B Value | C Growth | C Momentum | B VGM

Industry Rank:

Top 40%(106 out of 265)
Industry: Utility - Electric Power

View All Zacks #1 Ranked Stocks

Trades from $1

Detailed Estimates

Enter Symbol

Estimates	
Next Report Date	8/2/18
Current Quarter	0.41
EPS Last Quarter	1.55
Last EPS Surprise	5.16%
ABR	2.40

Earnings ESP	0.00%
Current Year	3.40
Next Year	3.44
EPS (TTM)	3.52
P/E (F1)	16.53

Growth Estimates	BKH	IND	S&P
Current Qtr (06/2018)	0.00	-15.71	28.38
Next Qtr (09/2018)	-2.00	11.59	24.55
Current Year (12/2018)	1.19	6.80	NA
Next Year (12/2019)	1.18	6.60	7.10
Past 5 Years	9.20	6.50	NA
Next 5 Years	4.40	6.90	NA
PE	16.53	23.50	17.55
PEG Ratio	3.74	3.41	NA

Learn More About Estimate Research

See Brokerage Recommendations

See Earnings Report Transcript

Premium Research for BKH

Zacks Rank	**Hold 3**
Zacks Industry Rank	Top 40%(106 out of 265)
Zacks Sector Rank	Bottom 13% (14 out of 16)
Style Scores	**B Value | C Growth | C Momentum | B VGM**
Earnings ESP	0.00%
Research Report for BKH	Snapshot

(= Change in last 30 days)

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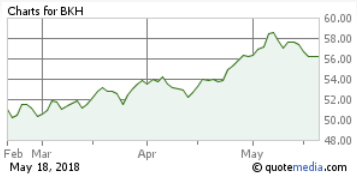
Research for BKH

Chart for BKH



Interactive Chart | Fundamental Charts

Predict to see real-time community sentiment

BKH Black Hills Cor…	Monday	In a Week	In a Month	In 3 Months
	▲ ▼	▲ ▼	▲ ▼	▲ ▼

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Sales Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	362.46M	370.95M	1.72B	1.75B
# of Estimates	1	1	2	2
High Estimate	362.46M	370.95M	1.79B	1.80B
Low Estimate	362.46M	370.95M	1.65B	1.70B

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Year ago Sales	348.00M	342.10M	1.70B	1.72B
Year over Year Growth Est.	4.16%	8.43%	1.14%	1.69%

Earnings Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.41	0.49	3.40	3.44
# of Estimates	3	2	3	3
Most Recent Consensus	0.43	NA	NA	NA
High Estimate	0.43	0.55	3.42	3.46
Low Estimate	0.37	0.43	3.39	3.42
Year ago EPS	0.41	0.50	3.36	3.40
Year over Year Growth Est.	0.00%	-2.00%	1.19%	1.08%

Agreement - Estimate Revisions

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	1	0	0	1
Up Last 60 Days	1	0	0	1
Down Last 7 Days	0	0	0	0
Down Last 30 Days	1	1	1	0
Down Last 60 Days	1	1	0	1

Magnitude - Consensus Estimate Trend

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.41	0.49	3.40	3.44
7 Days Ago	0.41	0.49	3.40	3.44
30 Days Ago	0.43	0.51	3.41	3.45
60 Days Ago	0.43	0.52	3.40	3.47
90 Days Ago	0.43	0.52	3.40	3.48

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	0.41	0.49	3.40	3.44
Zacks Consensus Estimate	0.41	0.49	3.40	3.44
Earnings ESP	0.00%	0.00%	0.00%	0.10%

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)

Surprise - Reported Earnings History

	Quarter Ending (3/2018)	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Average Surprise
Reported	1.63	0.98	0.50	0.41	NA
Estimate	1.55	1.07	0.55	0.51	NA
Difference	0.08	-0.09	-0.05	-0.10	-0.04
Surprise	5.16%	-8.41%	-9.09%	-19.61%	-7.99%

Quarterly Estimates By Analyst

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Annual Estimates By Analyst

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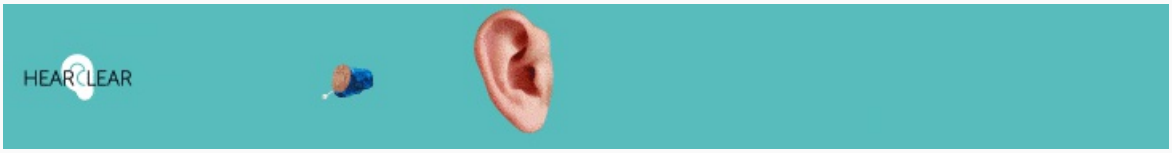

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El Paso Electric Company (EE)

(Real Time Quote from BATS)

$54.70 USD

+0.30 (0.55%)

Updated May 18, 2018 09:52 AM ET

Add to portfolio

Zacks Rank:

4-Sell

Style Scores:

D Value | C Growth | A Momentum | C VGM

Industry Rank:

Top 40%(106 out of 265)
Industry: Utility - Electric Power

View All Zacks #1 Ranked Stocks

Trades from $1

Detailed Estimates

Enter Symbol

Estimates	
Next Report Date	8/1/18
Current Quarter	NA
EPS Last Quarter	NA
Last EPS Surprise	NA
ABR	3.00

Earnings ESP	0.00%
Current Year	2.60
Next Year	2.64
EPS (TTM)	2.40
P/E (F1)	20.92

Growth Estimates	EE	IND	S&P
Current Qtr (06/2018)	NA	-15.71	28.38
Next Qtr (09/2018)	NA	11.59	24.55
Current Year (12/2018)	7.44	6.80	NA
Next Year (12/2019)	1.54	6.60	7.10
Past 5 Years	0.70	6.50	NA
Next 5 Years	5.10	6.90	NA
PE	20.92	23.50	17.55
PEG Ratio	4.10	3.41	NA

Learn More About Estimate Research

See Brokerage Recommendations

See Earnings Report Transcript

Premium Research for EE

Zacks Rank	▲ **Sell** 4
Zacks Industry Rank	Top 40%(106 out of 265)
Zacks Sector Rank	Bottom 13% (14 out of 16)
Style Scores	D **Value** | C **Growth** | A **Momentum** | C **VGM**
Earnings ESP	0.00%
Research Report for EE	Snapshot

(▲ ▼ = Change in last 30 days)

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Research for EE

Chart for EE

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Average Gain Per Year

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	Monday	In a Week	In a Month	In 3 Months
EE El Paso Electri…	▲ ▼	▲ ▼	▲ ▼	▲ ▼

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Sales Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	M	NA	NA	NA
# of Estimates	NA	NA	NA	NA
High Estimate	NA	NA	NA	NA
Low Estimate	NA	NA	NA	NA
Year ago Sales	251.84M	297.47M	916.80M	NA
Year over Year Growth Est	NA	NA	NA	NA

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Year over Year Growth Est.	NA	NA	NA	NA

Earnings Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	NA	NA	2.60	2.64
# of Estimates	NA	NA	1	1
Most Recent Consensus	NA	NA	NA	NA
High Estimate	NA	NA	2.60	2.64
Low Estimate	NA	NA	2.60	2.64
Year ago EPS	0.89	1.47	2.42	2.60
Year over Year Growth Est.	NA	NA	7.44%	1.54%

Agreement - Estimate Revisions

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	NA	NA	0	0
Up Last 30 Days	NA	NA	0	0
Up Last 60 Days	NA	NA	0	0
Down Last 7 Days	NA	NA	0	0
Down Last 30 Days	NA	NA	1	0
Down Last 60 Days	NA	NA	1	0

Magnitude - Consensus Estimate Trend

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	NA	NA	2.60	2.64
7 Days Ago	NA	NA	2.60	2.64
30 Days Ago	NA	NA	2.58	2.65
60 Days Ago	NA	NA	2.58	2.65
90 Days Ago	NA	NA	2.66	NA

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	NA	NA	2.60	2.64
Zacks Consensus Estimate	NA	NA	2.60	2.64
Earnings ESP	0.00%	0.00%	0.00%	0.00%

Surprise - Reported Earnings History

	Quarter Ending (3/2018)	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Average Surprise
Reported	-0.12	0.16	1.47	0.89	NA
Estimate	NA	0.22	1.58	0.75	NA
Difference	NA	-0.06	-0.11	0.14	-0.01
Surprise	NA	-27.27%	-6.96%	18.67%	-5.19%

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Hawaiian Electric Industries, Inc. (HE)

(Real Time Quote from BATS)

$33.08 USD

-0.06 (-0.18%)

Updated May 18, 2018 09:52 AM ET

Add to portfolio

Zacks Rank:

2-Buy

Style Scores:

C Value | D Growth | A Momentum | C VGM

Industry Rank:

Top 40%(106 out of 265)
Industry: Utility - Electric Power

View All Zacks #1 Ranked Stocks

Trades from $1

Detailed Estimates

Enter Symbol

Estimates	
Next Report Date	8/2/18
Current Quarter	0.42
EPS Last Quarter	0.37
Last EPS Surprise	0.00%
ABR	3.75
Earnings ESP	0.00%
Current Year	1.91
Next Year	2.05
EPS (TTM)	1.71
P/E (F1)	17.35

Growth Estimates	HE	IND	S&P
Current Qtr (06/2018)	16.67	-15.71	28.38
Next Qtr (09/2018)	12.73	11.59	24.55
Current Year (12/2018)	15.76	6.80	NA
Next Year (12/2019)	7.33	6.60	7.10
Past 5 Years	0.90	6.50	NA
Next 5 Years	7.10	6.90	NA
PE	17.35	23.50	17.55
PEG Ratio	2.46	3.41	NA

Learn More About Estimate Research

See Brokerage Recommendations

See Earnings Report Transcript

Premium Research for HE

Zacks Rank	▲ Buy 2
Zacks Industry Rank	Top 40%(106 out of 265)
Zacks Sector Rank	Bottom 13% (14 out of 16)
Style Scores	C Value | D Growth | A Momentum | C VGM
Earnings ESP	0.00%
Research Reports for HE	Analyst | Snapshot

(= Change in last 30 days)

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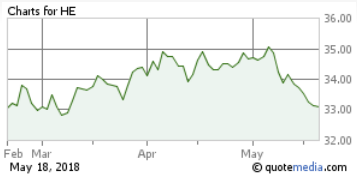
Research for HE

Analyst Snapshot

Chart for HE



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HE Hawaiian Electr…	Monday	In a Week	In a Month	In 3 Months
	▲ ▼	▲ ▼	▲ ▼	▲ ▼

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Sales Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	638.52M	675.99M	2.60B	2.55B
# of Estimates	1	1	2	2
High Estimate	638.52M	675.99M	2.62B	2.63B
Low Estimate	638.52M	675.99M	2.58B	2.46B

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Year ago Sales	632.28M	673.19M	2.56B	2.60B
Year over Year Growth Est.	0.99%	0.42%	1.73%	-2.10%

Earnings Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.42	0.62	1.91	2.05
# of Estimates	2	2	3	3
Most Recent Consensus	NA	NA	NA	NA
High Estimate	0.43	0.63	1.97	2.16
Low Estimate	0.41	0.61	1.86	1.98
Year ago EPS	0.36	0.55	1.65	1.91
Year over Year Growth Est.	16.67%	12.73%	15.76%	7.16%

Agreement - Estimate Revisions

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	1	0	0	2
Up Last 30 Days	1	0	1	2
Up Last 60 Days	0	0	1	2
Down Last 7 Days	0	1	0	0
Down Last 30 Days	0	1	0	0
Down Last 60 Days	0	0	0	0

Magnitude - Consensus Estimate Trend

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.42	0.62	1.91	2.05
7 Days Ago	0.39	0.63	1.92	2.06
30 Days Ago	0.41	0.63	1.88	2.00
60 Days Ago	0.43	0.63	1.88	2.00
90 Days Ago	0.43	0.63	1.88	1.95

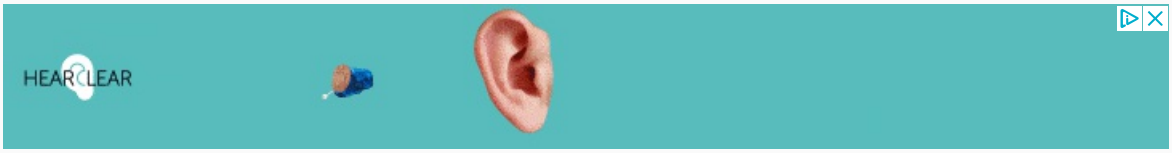
Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	0.42	0.62	1.91	2.05
Zacks Consensus Estimate	0.42	0.62	1.91	2.05
Earnings ESP	0.00%	0.00%	0.00%	0.00%

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)

Surprise - Reported Earnings History

	Quarter Ending (3/2018)	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Average Surprise
Reported	0.37	0.43	0.55	0.36	NA
Estimate	0.37	0.41	0.57	0.39	NA
Difference	0.00	0.02	-0.02	-0.03	-0.01
Surprise	0.00%	4.88%	-3.51%	-7.69%	-1.58%



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Real time prices by BATS. Delayed quotes by Sungard.

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IDACORP, Inc. (IDA)

(Real Time Quote from BATS)

$88.28 USD

+0.24 (0.27%)

Updated May 18, 2018 09:50 AM ET

Add to portfolio

Zacks Rank:

3-Hold

Style Scores:

D Value | D Growth | B Momentum | D VGM

Industry Rank:

Top 40%(106 out of 265)
Industry: Utility - Electric Power

View All Zacks #1 Ranked Stocks

Trades from $1

Detailed Estimates

Enter Symbol

Estimates	
Next Report Date	8/2/18
Current Quarter	1.00
EPS Last Quarter	0.71
Last EPS Surprise	1.41%
ABR	3.25

Earnings ESP	0.00%
Current Year	4.19
Next Year	4.34
EPS (TTM)	4.28
P/E (F1)	21.00

Growth Estimates	IDA	IND	S&P
Current Qtr (06/2018)	1.01	-15.71	28.38
Next Qtr (09/2018)	-3.89	11.59	24.55
Current Year (12/2018)	-0.48	6.80	NA
Next Year (12/2019)	3.58	6.60	7.10
Past 5 Years	4.00	6.50	NA
Next 5 Years	3.90	6.90	NA
PE	21.00	23.50	17.55
PEG Ratio	5.43	3.41	NA

Learn More About Estimate Research

See Brokerage Recommendations

See Earnings Report Transcript

Premium Research for IDA

Zacks Rank	Hold 3
Zacks Industry Rank	Top 40%(106 out of 265)
Zacks Sector Rank	Bottom 13% (14 out of 16)
Style Scores	D Value | D Growth | B Momentum | D VGM
Earnings ESP	0.00%
Research Reports for IDA	Analyst | Snapshot

(▲ ▼ = Change in last 30 days)

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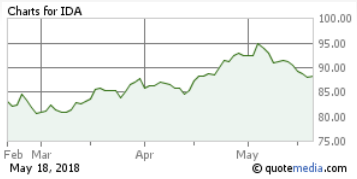
Research for IDA

Analyst

Chart for IDA



Interactive Chart | Fundamental Charts

Predict to see real-time community sentiment

IDA Idacorp, Inc.	Monday	In a Week	In a Month	In 3 Months
	▲ ▼	▲ ▼	▲ ▼	▲ ▼

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Sales Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	M	NA	NA	NA
# of Estimates	NA	NA	NA	NA
High Estimate	NA	NA	NA	NA
Low Estimate	NA	NA	NA	NA

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Year ago Sales	333.01M	408.32M	1.35B	NA
Year over Year Growth Est.	NA	NA	NA	NA

Earnings Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	1.00	1.73	4.19	4.34
# of Estimates	1	1	3	2
Most Recent Consensus	1.00	1.73	4.20	4.35
High Estimate	1.00	1.73	4.20	4.35
Low Estimate	1.00	1.73	4.18	4.32
Year ago EPS	0.99	1.80	4.21	4.19
Year over Year Growth Est.	1.01%	-3.89%	-0.48%	3.38%

Agreement - Estimate Revisions

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Up Last 60 Days	0	0	1	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	1	1	0	0
Down Last 60 Days	1	1	0	0

Magnitude - Consensus Estimate Trend

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	1.00	1.73	4.19	4.34
7 Days Ago	1.00	1.73	4.19	4.34
30 Days Ago	1.02	1.74	4.19	4.34
60 Days Ago	1.02	1.74	4.18	4.32
90 Days Ago	NA	NA	4.16	NA

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	1.00	1.73	4.19	4.34
Zacks Consensus Estimate	1.00	1.73	4.19	4.34
Earnings ESP	0.00%	0.00%	0.08%	0.00%

Earnings ESP	0.00% Current Qtr (6/2018)	0.00% Next Qtr (9/2018)	-0.06% Current Year (12/2018)	0.00% Next Year (12/2019)

Surprise - Reported Earnings History

	Quarter Ending (3/2018)	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Average Surprise
Reported	0.72	0.77	1.80	0.99	NA
Estimate	0.71	0.66	1.66	1.06	NA
Difference	0.01	0.11	0.14	-0.07	0.05
Surprise	1.41%	16.67%	8.43%	-6.60%	4.98%

Quarterly Estimates By Analyst

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BBB Rating: A+
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Real time prices by BATS. Delayed quotes by Sungard.

NYSE and AMEX data is at least 20 minutes delayed. NASDAQ data is at least 15 minutes delayed.

Alliant Energy Corporation (LNT)

(Real Time Quote from BATS)

$40.66 USD

+0.02 (0.05%)

Updated May 18, 2018 09:50 AM ET

Add to portfolio

Zacks Rank:

3-Hold

Style Scores:

C Value | F Growth | C Momentum | D VGM

Industry Rank:

Top 40%(106 out of 265)
Industry: Utility - Electric Power

View All Zacks #1 Ranked Stocks

Trades from $1

Detailed Estimates

Enter Symbol

Estimates	
Next Report Date	8/2/18
Current Quarter	0.43
EPS Last Quarter	0.51
Last EPS Surprise	1.96%
ABR	3.00
Earnings ESP	0.00%
Current Year	2.12
Next Year	2.25
EPS (TTM)	2.01
P/E (F1)	19.17

Growth Estimates	LNT	IND	S&P
Current Qtr (06/2018)	4.88	-15.71	28.38
Next Qtr (09/2018)	6.67	11.59	24.55
Current Year (12/2018)	9.84	6.80	NA
Next Year (12/2019)	6.13	6.60	7.10
Past 5 Years	5.00	6.50	NA
Next 5 Years	5.60	6.90	NA
PE	19.17	23.50	17.55
PEG Ratio	3.44	3.41	NA

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See Brokerage Recommendations

See Earnings Report Transcript

Premium Research for LNT

Zacks Rank	Hold 3
Zacks Industry Rank	Top 40%(106 out of 265)
Zacks Sector Rank	Bottom 13% (14 out of 16)
Style Scores	C Value | F Growth | C Momentum | D VGM
Earnings ESP	0.00%
Research Reports for LNT	Analyst | Snapshot

(= Change in last 30 days)

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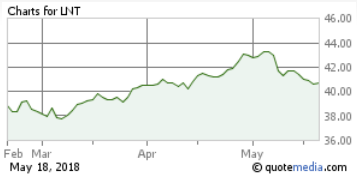
Research for LNT

Analyst Snapshot

Chart for LNT



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Predict to see real-time community sentiment

LNT Alliant Energy …	Monday	In a Week	In a Month	In 3 Months
	▲ ▼	▲ ▼	▲ ▼	▲ ▼

Predicting constitutes acceptance of PredictWallStreet's terms of use.

Sales Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	M	NA	3.48B	3.64B
# of Estimates	NA	NA	1	1
High Estimate	NA	NA	3.48B	3.64B
Low Estimate	NA	NA	3.48B	3.64B
Year ago Sales	765.30M	906.90M	3.38B	3.48B
Year over Year Growth Est.	NA	NA	2.89%	4.66%

Earnings Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.43	0.80	2.12	2.25
# of Estimates	2	1	3	3
Most Recent Consensus	NA	0.80	NA	NA
High Estimate	0.45	0.80	2.12	2.27
Low Estimate	0.40	0.80	2.12	2.22
Year ago EPS	0.41	0.75	1.93	2.12
Year over Year Growth Est.	4.88%	6.67%	9.84%	5.98%

Agreement - Estimate Revisions

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	1	0
Up Last 60 Days	0	0	1	1
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	1	0	0
Down Last 60 Days	0	1	0	0

Magnitude - Consensus Estimate Trend

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.43	0.80	2.12	2.25
7 Days Ago	0.43	0.80	2.12	2.25
30 Days Ago	0.45	0.82	2.11	2.24
60 Days Ago	0.45	0.82	2.11	2.23
90 Days Ago	NA	NA	2.12	2.20

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	0.43	0.80	2.12	2.25
Zacks Consensus Estimate	0.43	0.80	2.12	2.25
Earnings ESP	0.00%	0.00%	0.00%	0.00%

Surprise - Reported Earnings History

	Quarter Ending (3/2018)	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Average Surprise
Reported	0.52	0.33	0.75	0.41	NA
Estimate	0.51	0.38	0.88	0.39	NA
Difference	0.01	-0.05	-0.13	0.02	-0.04
Surprise	1.96%	-13.16%	-14.77%	5.13%	-5.21%

Quarterly Estimates By Analyst

Zacks Premium Subscription Required Learn more

Annual Estimates By Analyst

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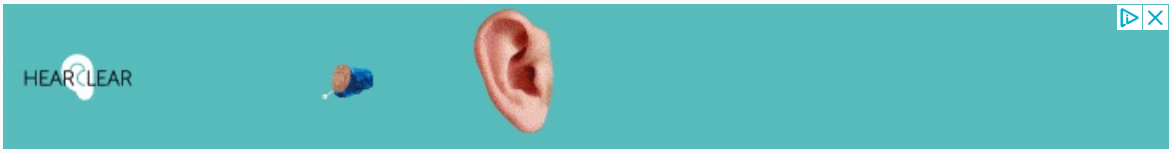

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Real time prices by BATS. Delayed quotes by Sungard.

NYSE and AMEX data is at least 20 minutes delayed. NASDAQ data is at least 15 minutes delayed.

NorthWestern Corporation (NWE)

(Real Time Quote from BATS)

$53.29 USD

+0.03 (0.06%)

Updated May 18, 2018 09:52 AM ET

Add to portfolio

Zacks Rank:

2-Buy

Style Scores:

B Value | C Growth | D Momentum | C VGM

Industry Rank:

Top 40%(106 out of 265)
Industry: Utility - Electric Power

View All Zacks #1 Ranked Stocks

Trades from $1

Detailed Estimates

Enter Symbol

Estimates

Next Report Date	7/24/18
Current Quarter	0.42
EPS Last Quarter	1.20
Last EPS Surprise	-1.67%
ABR	3.75

Earnings ESP	0.00%
Current Year	3.42
Next Year	3.43
EPS (TTM)	3.38
P/E (F1)	15.56

Growth Estimates	NWE	IND	S&P
Current Qtr (06/2018)	-10.64	-15.71	28.38
Next Qtr (09/2018)	0.00	11.59	24.55
Current Year (12/2018)	3.64	6.80	NA
Next Year (12/2019)	0.29	6.60	7.10
Past 5 Years	6.30	6.50	NA
Next 5 Years	2.40	6.90	NA
PE	15.56	23.50	17.55
PEG Ratio	6.46	3.41	NA

Learn More About Estimate Research

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See Earnings Report Transcript

Premium Research for NWE

Zacks Rank	▲ Buy 2
Zacks Industry Rank	Top 40%(106 out of 265)
Zacks Sector Rank	Bottom 13% (14 out of 16)
Style Scores	B Value | C Growth | D Momentum | C VGM
Earnings ESP	0.00%
Research Report for NWE	Snapshot

(= Change in last 30 days)

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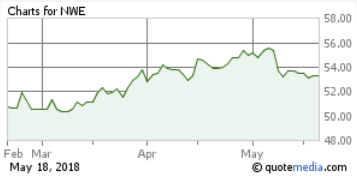
Research for NWE

Snapshot

Chart for NWE



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Predict to see real-time community sentiment

	Monday	In a Week	In a Month	In 3 Months
NWE Northwestern Co…	▲ ▼	▲ ▼	▲ ▼	▲ ▼

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Sales Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	M	NA	1.31B	1.34B
# of Estimates	NA	NA	1	1
High Estimate	NA	NA	1.31B	1.34B
Low Estimate	NA	NA	1.31B	1.34B

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Year ago Sales	283.86M	309.93M	1.31B	1.31B
Year over Year Growth Est.	NA	NA	0.33%	2.14%

Earnings Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.42	0.75	3.42	3.43
# of Estimates	2	1	3	3
Most Recent Consensus	NA	0.75	NA	3.45
High Estimate	0.48	0.75	3.45	3.45
Low Estimate	0.35	0.75	3.40	3.40
Year ago EPS	0.47	0.75	3.30	3.42
Year over Year Growth Est.	-10.64%	0.00%	3.64%	0.10%

Agreement - Estimate Revisions

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	1	1
Up Last 60 Days	0	0	1	1
Down Last 7 Days	0	0	0	0
Down Last 30 Days	0	1	0	0
Down Last 60 Days	0	1	0	0

Magnitude - Consensus Estimate Trend

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.42	0.75	3.42	3.43
7 Days Ago	0.42	0.75	3.42	3.43
30 Days Ago	0.48	0.76	3.42	3.42
60 Days Ago	0.48	0.76	3.42	3.41
90 Days Ago	0.48	0.75	3.43	3.36

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	0.42	0.75	3.42	3.43
Zacks Consensus Estimate	0.42	0.75	3.42	3.43
Earnings ESP	0.00%	0.00%	0.00%	0.00%

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)

Surprise - Reported Earnings History

	Quarter Ending (3/2018)	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Average Surprise
Reported	1.18	0.98	0.75	0.47	NA
Estimate	1.20	1.02	0.70	0.62	NA
Difference	-0.02	-0.04	0.05	-0.15	-0.04
Surprise	-1.67%	-3.92%	7.14%	-24.19%	-5.66%

Quarterly Estimates By Analyst

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Annual Estimates By Analyst

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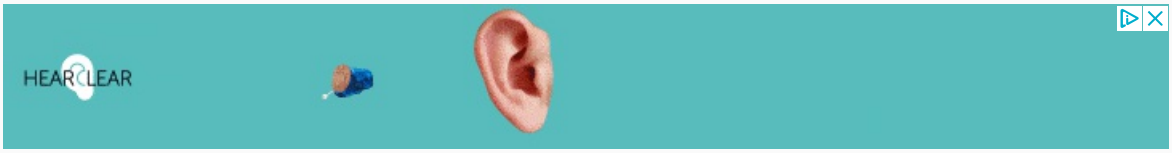

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Real time prices by BATS. Delayed quotes by Sungard.

NYSE and AMEX data is at least 20 minutes delayed. NASDAQ data is at least 15 minutes delayed.

OGE Energy Corporation (OGE)

(Real Time Quote from BATS)

$33.57 USD

+0.26 (0.78%)

Updated May 18, 2018 09:54 AM ET

Add to portfolio

Zacks Rank:

3-Hold

Style Scores:

D Value | C Growth | B Momentum | C VGM

Industry Rank:

Top 40%(106 out of 265)
Industry: Utility - Electric Power

View All Zacks #1 Ranked Stocks

Trades from $1

Detailed Estimates

Enter Symbol

Estimates	
Next Report Date	8/2/18
Current Quarter	0.52
EPS Last Quarter	0.17
Last EPS Surprise	58.82%
ABR	2.33

Earnings ESP	0.00%
Current Year	2.00
Next Year	2.12
EPS (TTM)	2.01
P/E (F1)	16.68

Growth Estimates	OGE	IND	S&P
Current Qtr (06/2018)	0.00	-15.71	28.38
Next Qtr (09/2018)	0.00	11.59	24.55
Current Year (12/2018)	4.17	6.80	NA
Next Year (12/2019)	6.00	6.60	7.10
Past 5 Years	1.10	6.50	NA
Next 5 Years	6.00	6.90	NA
PE	16.68	23.50	17.55
PEG Ratio	2.80	3.41	NA

Learn More About Estimate Research

See Brokerage Recommendations

See Earnings Report Transcript

Premium Research for OGE

Zacks Rank	▼ Hold 3
Zacks Industry Rank	Top 40%(106 out of 265)
Zacks Sector Rank	Bottom 13% (14 out of 16)
Style Scores	D Value | C Growth | B Momentum | C VGM
Earnings ESP	0.00%
Research Reports for OGE	Analyst | Snapshot

(▲ ▼ = Change in last 30 days)

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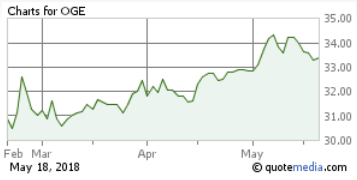
Research for OGE

Analyst

Chart for OGE



Interactive Chart | Fundamental Charts

Predict to see real-time community sentiment

	Monday	In a Week	In a Month	In 3 Months
OGE Oge Energy Corp…	▲ ▼	▲ ▼	▲ ▼	▲ ▼

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Sales Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	M	NA	NA	NA
# of Estimates	NA	NA	NA	NA
High Estimate	NA	NA	NA	NA
Low Estimate	NA	NA	NA	NA

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Year ago Sales	586.40M	716.80M	2.26B	NA
Year over Year Growth Est.	NA	NA	NA	NA

Earnings Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.52	0.92	2.00	2.12
# of Estimates	1	1	4	3
Most Recent Consensus	0.52	0.92	NA	2.10
High Estimate	0.52	0.92	2.01	2.15
Low Estimate	0.52	0.92	1.98	2.10
Year ago EPS	0.52	0.92	1.92	2.00
Year over Year Growth Est.	0.00%	0.00%	4.17%	6.29%

Agreement - Estimate Revisions

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Up Last 60 Days	0	0	0	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	1	1	0	0
Down Last 60 Days	1	1	0	0

Magnitude - Consensus Estimate Trend

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.52	0.92	2.00	2.12
7 Days Ago	0.52	0.92	2.00	2.12
30 Days Ago	0.53	0.96	2.00	2.12
60 Days Ago	0.53	0.96	2.00	2.14
90 Days Ago	NA	NA	1.99	NA

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	0.52	0.92	2.00	2.11
Zacks Consensus Estimate	0.52	0.92	2.00	2.12
Earnings ESP	0.00%	0.00%	-0.04%	-0.63%

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)

Surprise - Reported Earnings History

	Quarter Ending (3/2018)	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Average Surprise
Reported	0.27	0.30	0.92	0.52	NA
Estimate	0.17	0.28	0.93	0.47	NA
Difference	0.10	0.02	-0.01	0.05	0.04
Surprise	58.82%	7.14%	-1.08%	10.64%	18.88%

Quarterly Estimates By Analyst

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BBB Rating: A+
as of 5/17/2018
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Real time prices by BATS. Delayed quotes by Sungard.

NYSE and AMEX data is at least 20 minutes delayed. NASDAQ data is at least 15 minutes delayed.

PNM Resources, Inc. (Holding Co.) (PNM)

(Real Time Quote from BATS)

$37.85 USD

+0.05 (0.13%)

Updated May 18, 2018 09:52 AM ET

Add to portfolio

Zacks Rank:

3-Hold

Style Scores:

C Value | D Growth | B Momentum | C VGM

Industry Rank:

Top 40%(106 out of 265)
Industry: Utility - Electric Power

View All Zacks #1 Ranked Stocks

Trades from $1

Detailed Estimates

Enter Symbol

Estimates	
Next Report Date	7/27/18
Current Quarter	0.45
EPS Last Quarter	0.21
Last EPS Surprise	0.00%
ABR	3.56
Earnings ESP	0.00%
Current Year	1.87
Next Year	2.08
EPS (TTM)	1.87
P/E (F1)	20.21

Growth Estimates	PNM	IND	S&P
Current Qtr (06/2018)	-8.16	-15.71	28.38
Next Qtr (09/2018)	12.90	11.59	24.55
Current Year (12/2018)	-3.61	6.80	NA
Next Year (12/2019)	11.23	6.60	7.10
Past 5 Years	8.80	6.50	NA
Next 5 Years	5.10	6.90	NA
PE	20.21	23.50	17.55
PEG Ratio	3.95	3.41	NA

Learn More About Estimate Research

See Brokerage Recommendations

See Earnings Report Transcript

Premium Research for PNM

Zacks Rank	Hold 3
Zacks Industry Rank	Top 40%(106 out of 265)
Zacks Sector Rank	Bottom 13% (14 out of 16)
Style Scores	C Value | D Growth | B Momentum | C VGM
Earnings ESP	0.00%
Research Report for PNM	Snapshot

(= Change in last 30 days)

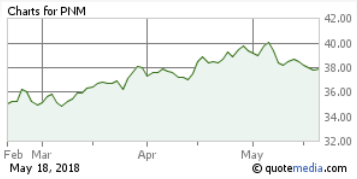
View All Zacks Rank #1 Strong Buys

More Premium Research »

Research for PNM

Snapshot

Chart for PNM



Interactive Chart | Fundamental Charts

Predict to see real-time community sentiment

PNM Pnm Resources, …	Monday	In a Week	In a Month	In 3 Months
	▲ ▼	▲ ▼	▲ ▼	▲ ▼

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Sales Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	M	NA	1.48B	1.53B
# of Estimates	NA	NA	2	2
High Estimate	NA	NA	1.48B	1.53B
Low Estimate	NA	NA	1.48B	1.52B

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Year ago Sales	362.32M	419.90M	1.45B	1.48B
Year over Year Growth Est.	NA	NA	2.32%	3.15%

Earnings Estimates

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Zacks Consensus Estimate	0.45	1.05	1.87	2.08
# of Estimates	2	2	4	4
Most Recent Consensus	0.39	NA	NA	NA
High Estimate	0.50	1.05	1.89	2.10
Low Estimate	0.39	1.05	1.85	2.05
Year ago EPS	0.49	0.93	1.94	1.87
Year over Year Growth Est.	-8.16%	12.90%	-3.61%	11.36%

Agreement - Estimate Revisions

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Up Last 7 Days	0	0	0	0
Up Last 30 Days	0	0	0	0
Up Last 60 Days	0	0	1	0
Down Last 7 Days	0	0	0	0
Down Last 30 Days	1	0	0	0
Down Last 60 Days	1	0	0	0

Magnitude - Consensus Estimate Trend

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Current	0.45	1.05	1.87	2.08
7 Days Ago	0.45	1.05	1.87	2.08
30 Days Ago	0.50	1.05	1.87	2.09
60 Days Ago	0.50	1.05	1.83	2.08
90 Days Ago	0.47	0.84	1.74	2.09

Upside - Most Accurate Estimate Versus Zacks Consensus

	Current Qtr (6/2018)	Next Qtr (9/2018)	Current Year (12/2018)	Next Year (12/2019)
Most Accurate Estimate	0.45	1.05	1.87	2.08
Zacks Consensus Estimate	0.45	1.05	1.87	2.08
Earnings ESP	0.00%	0.00%	0.00%	0.00%

Earnings ESP	0.00% Current Qtr (6/2018)	0.00% Next Qtr (9/2018)	0.00% Current Year (12/2018)	0.00% Next Year (12/2019)

Surprise - Reported Earnings History

	Quarter Ending (3/2018)	Quarter Ending (12/2017)	Quarter Ending (9/2017)	Quarter Ending (6/2017)	Average Surprise
Reported	0.21	0.24	0.93	0.49	NA
Estimate	0.21	0.19	0.85	0.45	NA
Difference	0.00	0.05	0.08	0.04	0.04
Surprise	0.00%	26.32%	9.41%	8.89%	11.16%

Quarterly Estimates By Analyst

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Annual Estimates By Analyst

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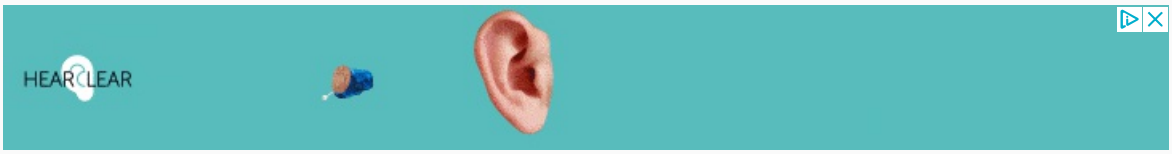

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